UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579

OGE ENERGY CORP.
(Exact name of registrant as specified in its charter)

Oklahoma	**73-1481638**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)
Registrant's telephone number, including area code: **405-553-3000**

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

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☑ Yes o No

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). ☑ Yes o No

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

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

Large accelerated filer ☑	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes ☑ No

At June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $6,525,558,217 based on the number of shares held by non-affiliates (199,253,686) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $32.75.

At January 31, 2017, there were 199,703,952 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2017 annual meeting of shareowners is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2016

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GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this Form 10-K.

Abbreviation	Definition
401(k) Plan	Qualified defined contribution retirement plan
ALJ	Administrative Law Judge
APSC	Arkansas Public Service Commission
ArcLight group	Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC, collectively
ASC	Financial Accounting Standards Board Accounting Standards Codification
ASU	Financial Accounting Standards Board Accounting Standards Update
AVEC	Arkansas Valley Electric Cooperative Corporation
Bbl/d	Barrels per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Btu	British thermal unit
CSAPR	Cross-State Air Pollution Rule
CenterPoint	CenterPoint Energy Resources Corp., wholly-owned subsidiary of CenterPoint Energy, Inc.
CO_2	Carbon dioxide
Code	Internal Revenue Code of 1986
Company	OGE Energy, collectively with its subsidiaries
Dry Scrubbers	Dry flue gas desulfurization units with spray dryer absorber
ECP	Environmental Compliance Plan
EGT	Enable Gas Transmission, LLC, a wholly-owned subsidiary of Enable that operates a 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex basins in Oklahoma, Texas, Arkansas, Louisiana and Kansas
Enable	Enable Midstream Partners, LP, partnership between OGE Energy, the ArcLight Group and CenterPoint Energy, Inc. formed to own and operate the midstream businesses of OGE Energy and CenterPoint
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings LLC
Enogex LLC	Enogex LLC collectively with its subsidiaries (effective June 30, 2013, the name was changed to Enable Oklahoma Intrastate Transmission, LLC)
EOIT	Enable Oklahoma Intrastate Transmission, LLC formerly Enogex LLC, a wholly-owned subsidiary of Enable that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
Federal Clean Water Act	Federal Water Pollution Control Act of 1972, as amended
FERC	Federal Energy Regulatory Commission
FIP	Federal implementation plan
GAAP	Accounting principles generally accepted in the United States
IRP	Integrated Resource Plan
kV	Kilovolt
LDC	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area
LTSA	Long-Term Service Agreement
MATS	Mercury and Air Toxics Standards
MBbl/d	Thousand barrels per day
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
MRT	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of Enable that operates a 1,700-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois
Mustang Modernization Plan	OG&E's plan to replace the soon-to-be retired Mustang steam turbines with 400 MW of new, efficient combustion turbines at the Mustang site in 2017
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGLs	Natural gas liquids

NO_X	Nitrogen oxide
OCC	Oklahoma Corporation Commission
ODEQ	Oklahoma Department of Environmental Quality
OG&E	Oklahoma Gas and Electric Company, wholly-owned subsidiary of OGE Energy
OGE Holdings	OGE Enogex Holdings LLC, wholly-owned subsidiary of OGE Energy, parent company of Enogex Holdings and 25.7 percent owner of Enable Midstream Partners
OSHA	Federal Occupational Safety and Health Act of 1970
Pension Plan	Qualified defined benefit retirement plan
Ppb	Parts per billion
PUD	Public Utility Division of the Oklahoma Corporation Commission
QF	Qualified cogeneration facilities
QF contracts	Contracts with QFs and small power production producers
Regional Haze Rule	The EPA's regional haze rule
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan
SESH	Southeast Supply Header, LLC
SIP	State implementation plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
Stock Incentive Plan	2013 Stock Incentive Plan
System sales	Sales to OG&E's customers
TBtu/d	Trillion British thermal units per day

FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-K, including those matters discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations," are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate," "believe," "estimate," "expect," "intend," "objective," "plan," "possible," "potential," "project" and similar expressions. Actual results may vary materially from those expressed in forward-looking statements. In addition to the specific risk factors discussed in "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of the Company and its subsidiaries to access the capital markets and obtain financing on favorable terms as well as inflation rates and monetary fluctuations;
- the ability to obtain timely and sufficient rate relief to allow for recovery of items such as capital expenditures, fuel costs, operating costs, transmission costs and deferred expenditures;
- prices and availability of electricity, coal, natural gas and NGLs;
- the timing and extent of changes in commodity prices, particularly natural gas and NGLs, the competitive effects of the available pipeline capacity in the regions Enable serves, and the effects of geographic and seasonal commodity price differentials, including the effects of these circumstances on re-contracting available capacity on Enable's interstate pipelines;
- the timing and extent of changes in the supply of natural gas, particularly supplies available for gathering by Enable's gathering and processing business and transporting by Enable's interstate pipelines, including the impact of natural gas and NGLs prices on the level of drilling and production activities in the regions Enable serves;
- business conditions in the energy and natural gas midstream industries, including the demand for natural gas, NGLs, crude oil and midstream services;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- the impact on demand for our services resulting from cost-competitive advances in technology, such as distributed electricity generation and customer energy efficiency programs;
- technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;
- factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;
- availability and prices of raw materials for current and future construction projects;
- the effect of retroactive pricing of transactions in the SPP markets or adjustments in market pricing mechanisms by the SPP;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets;
- environmental laws, safety laws or other regulations that may impact the cost of operations or restrict or change the way the Company operates its facilities;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- the cost of protecting assets against, or damage due to, terrorism or cyberattacks and other catastrophic events;
- creditworthiness of suppliers, customers and other contractual parties;
- social attitudes regarding the utility, natural gas and power industries;
- identification of suitable investment opportunities to enhance shareholder returns and achieve long-term financial objectives through business acquisitions and divestitures;
- increased pension and healthcare costs;
- costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including, but not limited to, those described in this Form 10-K;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with the Company's equity investment in Enable that the Company does not control; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in "Item 1A. Risk Factors."

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I

Item 1. Business.

THE COMPANY

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and it lacks the power to direct activities that most significantly impact economic performance. The Company was incorporated in August 1995 in the state of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone 405-553-3000.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment represents the Company's investment in Enable through wholly owned subsidiaries, and ultimately OGE Holdings. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation, principally located in the Williston basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25.0 million common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2016, the Company owned 111.0 million common units, or 25.7 percent, of Enable's outstanding common units. Of the Company's 111.0 million common units, 68.2 million units were subordinated. The subordination period began on the closing date of Enable’s initial public offering and will extend until the first business day following the distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017. The Company anticipates that the subordination period will expire in August 2017 and will not impact future distributions that the Company receives from Enable. For additional information on the Company's equity investment in Enable and related party transactions, see Note 3.

Over the past two years, Enable has seen changes in producer activity due to the volatility of commodity prices. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. During 2016, those prices increased, and have stabilized, but have not rebounded to the pre-2015 levels. If commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted. A portion of our earnings and operating cash flows depend on the performance of, and distributions from, Enable. As disclosed in this Form 10-K, Enable is subject to a number of risks. If any of those risks were to occur, the Company's business, financial condition, results of operations or cash flows could be materially adversely affected.

On February 10, 2017, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common and subordinated units, which is unchanged from the previous quarter. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. The Company is entitled to 60 percent of those "incentive distributions."

Company Strategy

The Company's mission, through OG&E and its equity interest in Enable, is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customer's needs for energy and related services, focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and interest in a publicly traded midstream company, while providing competitive energy products and services to customers, as well as seeking growth opportunities in both businesses.

OG&E is focused on:

- Providing exceptional customer experiences by continuing to improve customer interfaces, tools, products and services that deliver high customer satisfaction and operating productivity.
- Providing safe, reliable energy to the communities and customers we serve. A particular focus is on enhancing the value of the grid by improving distribution grid reliability by reducing the frequency and duration of customer interruptions and leveraging previous grid technology investments.
- Having strong regulatory and legislative relationships for the long-term benefit of our customers, investors and members.
- Continuing to grow a zero-injury culture and deliver top-quartile safety results.
- Complying with the EPA's MATS and Regional Haze Rule requirements.
- Ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers.
- Continuing focus on operational excellence and efficiencies in order to protect the customer bill.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate for OG&E of three to five percent on a weather-normalized basis, maintaining a strong credit rating as well as targeting dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets and the composition of the Company's assets and investment opportunities. The Company also utilizes cash distributions from its investment in Enable to help fund its capital needs and support future dividend growth. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and having strong regulatory and legislative relationships.

ELECTRIC OPERATIONS - OG&E

General

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E. OG&E furnishes retail electric service in 267 communities and their contiguous rural and suburban areas. The service area covers 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas, the second largest city in that state. Of the 267 communities that OG&E serves, 241 are located in Oklahoma and 26 are in Arkansas. OG&E derived 92 percent of its total electric operating revenues in 2016 from sales in Oklahoma and the remainder from sales in Arkansas. OG&E does not currently serve wholesale customers in either state.

OG&E's system control area peak demand in 2016 was 6,538 MWs on August 11, 2016. OG&E's load responsibility peak demand was 6,008 MWs on August 11, 2016. As reflected in the table below and in the operating statistics that follow, there were 26.9 million MWh system sales in 2016, 27.2 million MWh system sales in 2015 and 28.0 million MWh system sales in 2014. Variations in system sales for the three years are reflected in the following table:

Year ended December 31	**2016**	**2016 vs. 2015**	2015	2015 vs. 2014	2014
System sales - (*Millions of MWh*)	**26.9**	**(1.1)%**	27.2	(2.9)%	28.0

OG&E is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators as well as from consumers choosing appliances powered by other energy sources. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. It is possible that changes in regulatory policies or advances in technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells will reduce costs of new technology to levels that are equal to or below that of most central station electricity production. Our ability to maintain relatively low cost, efficient and reliable operations is a significant determinate of our competitiveness.

OKLAHOMA GAS AND ELECTRIC COMPANY

CERTAIN OPERATING STATISTICS

Year ended December 31	**2016**	2015	2014
ELECTRIC ENERGY *(Millions of MWh)*			
Generation (exclusive of station use)	**21.4**	20.9	22.8
Purchased	**9.6**	9.2	8.8
Total generated and purchased	**31.0**	30.1	31.6
OG&E use, free service and losses	**(1.1)**	(1.2)	(1.4)
Electric energy sold	**29.9**	28.9	30.2
ELECTRIC ENERGY SOLD *(Millions of MWh)*			
Residential	**9.3**	9.2	9.4
Commercial	**7.6**	7.4	7.2
Industrial	**3.6**	3.6	3.8
Oilfield	**3.2**	3.4	3.4
Public authorities and street light	**3.2**	3.1	3.2
Sales for resale	**—**	0.5	1.0
System sales	**26.9**	27.2	28.0
Integrated market	**3.0**	1.7	2.2
Total sales	**29.9**	28.9	30.2
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 951.9**	$ 896.5	$ 925.5
Commercial	**573.7**	535.0	583.3
Industrial	**194.6**	190.6	224.5
Oilfield	**156.9**	162.8	188.3
Public authorities and street light	**204.3**	194.2	220.3
Sales for resale	**0.3**	21.7	52.9
System sales revenues	**2,081.7**	2,000.8	2,194.8
Provision for rate refund	**(33.6)**	—	—
Integrated market	**49.3**	48.6	94.1
Other	**161.8**	147.5	164.2
Total operating revenues	**$ 2,259.2**	$ 2,196.9	$ 2,453.1
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**712,467**	705,294	697,048
Commercial	**94,790**	93,401	91,966
Industrial	**2,831**	2,872	2,901
Oilfield	**6,469**	6,328	6,460
Public authorities and street light	**17,025**	16,880	16,581
Sales for resale	**—**	1	26
Total customers	**833,582**	824,776	814,982
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,342.88**	$ 1,278.51	$ 1,334.05
Average annual use (kilowatt-hour)	**13,105**	13,062	13,540
Average price per kilowatt-hour (cents)	**10.25**	9.79	9.85

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2016, 86 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and six percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid along with the corresponding process for allocating the costs of such expansions. Order No. 1000 requires individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariff and agreement provisions that establish any Federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities or to alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP's pre-Order No. 1000 tariff included a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build previous transmission projects in Oklahoma. On May 29, 2013, the Governor of Oklahoma signed House Bill 1932 into law which establishes a "right of first refusal" for Oklahoma incumbent transmission owners, including OG&E, to build new transmission projects with voltages under 300kV that interconnect to those incumbent owners' existing facilities.

The SPP has submitted compliance filings implementing Order No. 1000's requirements. In response, the FERC issued an order on the SPP filings that required the SPP to remove certain "right of first refusal" language from the SPP Tariff and the SPP Membership Agreement. On December 15, 2014, OG&E filed an appeal in the Court challenging the FERC's order requiring the removal of the "right of first refusal" language from the SPP Membership Agreement.

On July 1, 2016, the Court upheld the FERC's decision requiring removal of the "right of first refusal" for incumbent transmission providers from the SPP Membership Agreement. The Court determined that the FERC had reasonably found the "right of first refusal" in the SPP Membership Agreement to be anticompetitive.

The Company does not believe the Court’s ruling will have any impact on existing transmission projects for which the Company has already received a notice to construct from the SPP. The Company intends to actively participate in the SPP planning process for competitive transmission projects that we believe apply to transmission voltage levels projects greater than 300kV.

Fuel Adjustment Clause Review for Calendar Year 2014

On July 28, 2015, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2014, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On May 26, 2016, the OCC issued a final order, finding that for the calendar year 2014 OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent.

Oklahoma Demand Program Rider Review - SmartHours Program

In July 2012, OG&E filed an application with the OCC to recover certain costs associated with demand programs through the Oklahoma Demand Program Rider, including the lost revenues associated with the SmartHours program. The SmartHours program is designed to incentivize participating customers to reduce on-peak usage or shift usage to off-peak hours during the months of May through October, by offering lower rates to those customers in the off-peak hours of those months. Lost revenues are created by the difference in the standard rates and the lower incentivized rates. Non-SmartHours program customers benefit from the reduction of on-peak usage by SmartHours customers by the reduction of more costly on-peak generation and the delay in adding new on-peak generation.

In December 2012, the OCC issued an order approving the recovery of costs associated with the demand programs, including the lost revenues associated with the SmartHours program, subject to the PUD Staff's review.

In March 2014, the PUD Staff began their review of the demand program costs, including the lost revenues associated with the SmartHours program.

On August 9, 2016, OG&E entered into a settlement agreement with the PUD Staff to resolve the recoverable amount of lost revenues associated with the SmartHours program. The settlement provides for recovery of $10.1 million per year for 2013, 2014 and 2015, for a total of $30.3 million. OG&E had recorded $36.6 million of lost revenues for 2013, 2014 and 2015. On August 16, 2016, the OCC issued an order adopting the settlement agreement. Accordingly, OG&E reduced lost revenues and the Oklahoma Demand Program Rider regulatory asset by $6.3 million.

Mustang Modernization Plan - Arkansas

On April 13, 2016, OG&E filed an application at the APSC seeking authority to construct combustion turbines at its existing Mustang generating facility. Arkansas law requires a public utility to seek approval from the APSC to construct a power-generating facility located outside the boundaries of the state of Arkansas. The application did not seek any cost recovery for the capital expenditures in the application, as cost recovery will be determined in future proceedings. In July 2016, OG&E filed a motion to dismiss this proceeding and in August, the APSC approved the dismissal. OG&E intends to seek cost recovery of the Mustang combustion turbines at a later date after the Mustang facility is placed in service.

Pending Regulatory Matters

Set forth below is a list of various proceedings pending before state or federal regulatory agencies. Unless stated otherwise, OG&E cannot predict when the regulatory agency will act or what action the regulatory agency will take. OG&E's financial results are dependent in part on timely and adequate decisions by the regulatory agencies that set OG&E's rates.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA’s MATS and Regional Haze Rule FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP and for a recovery mechanism for the associated costs. The ECP includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asked the OCC to predetermine the prudence of its Mustang Modernization Plan, which calls for replacing OG&E's soon-to-be retired Mustang steam turbines with 400 MWs of new, efficient combustion turbines at the Mustang site and approval for a recovery mechanism for the associated costs.

On December 2, 2015, OG&E received an order from the OCC denying its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze Rule and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving its decision to install Dry Scrubbers at the Sooner facility. OG&E's application did not seek approval of the costs of the Dry Scrubber project. Instead, the reasonableness of the costs would be considered after the project is completed and OG&E seeks recovery in its rates. On April 28, 2016, the OCC approved the Dry Scrubber project.

Two parties appealed the OCC's decision to the Oklahoma Supreme Court. The Company is unable to predict what action the Oklahoma Supreme Court may take or the timing of any such action.

OG&E anticipates the total cost of Dry Scrubbers will be $547.5 million, including allowance for funds used during construction and capitalized ad valorem taxes. As of December 31, 2016, OG&E had invested $208.7 million of construction work in progress on the Dry Scrubbers. OG&E anticipates the total cost for the Mustang Modernization Plan will be $424.9 million and expects the project to be completed in late 2017. As of December 31, 2016, OG&E had invested $187.8 million on the Mustang Modernization Plan.

Integrated Resource Plans

In October 2015, OG&E finalized the 2015 IRP and submitted it to the OCC. The 2015 IRP updated certain assumptions contained in the IRP submitted in 2014, but did not make any material changes to the ECP and other parts of the plan. Currently, OG&E is scheduled to update its IRP in Arkansas by October 1, 2017 and in Oklahoma by October 1, 2018.

Oklahoma Rate Case Filing

On December 18, 2015, OG&E filed a general rate case with the OCC requesting a rate increase of $92.5 million and a 10.25 percent return on equity based on a common equity percentage of 53 percent. The rate case was based on a June 30, 2015 test year and included recovery of $1.6 billion of electric infrastructure additions since its last general rate case in Oklahoma, the impact of the expiration of OG&E's wholesale contracts, increased operating costs such as vegetation management and increased recovery of depreciation and plant dismantlement of approximately $8.0 million. Each 0.25 percent change in the requested return on equity affects the requested rate increase by approximately $9.0 million.

In late March 2016, the PUD Staff and other intervenors filed testimony in the case. The PUD Staff recommended a $6.1 million annual rate increase based on a return on equity of 9.25 percent and a common equity percentage of 53.0 percent. Included in the PUD Staff's recommendation is a reduction of $33.0 million to OG&E’s requested increase for depreciation and plant dismantlement.

The staff of the Oklahoma Attorney General made a recommendation to reduce rates $10.8 million based on a return on equity of 9.25 percent and a common equity percentage of 50 percent, as well as a recommendation to reduce rates $13.7 million based on a return on equity of 8.90 percent and a common equity percentage of 53 percent. Included in the Oklahoma Attorney General's recommendation is a reduction of $20.9 million to OG&E’s requested increase for depreciation and plant dismantlement.

The Oklahoma Industrial Energy Consumers recommended a $47.9 million annual rate decrease based on a return on equity of 9.00 percent and a common equity percentage of 53 percent. Included in the Oklahoma Industrial Energy Consumers' recommendation is a reduction of $52.5 million to OG&E’s requested increase for depreciation and plant dismantlement.

On July 1, 2016, OG&E implemented an annual interim rate increase of $69.5 million, which is subject to refund of any amount recovered in excess of the rates ultimately approved by the OCC in the rate case. As of December 31, 2016, the Company has recorded $39.0 million of revenues from the interim rate increase and has reserved $33.7 million of that revenue.

In December 2016, the ALJ issued a report and recommendations in the case. The ALJ's recommendations include, among other things, the use of OG&E's actual capital structure of 53 percent equity and 47 percent long-term debt and a return on equity of 9.87 percent resulting in an annual increase in OG&E's revenues of $40.7 million. The parties provided comments on the ALJ's report in early January 2017, and the OCC held hearings in early February 2017. The Company is unable to predict what action the OCC will take, or the timing of such action.

Arkansas Rate Case Filing

On August 25, 2016, OG&E filed a general rate case with the APSC. The rate filing requested a $16.5 million rate increase based on a 10.25 percent return on equity. The rate increase was based on a June 30, 2016 test year and included a recovery of over $3.0 billion of electric infrastructure additions since the last Arkansas general rate case in 2011. The increase also reflects increases in operation and maintenance expenses, including vegetation management costs, and increased recovery of depreciation and dismantlement costs. A hearing in this matter is scheduled for the second quarter of 2017.

Fuel Adjustment Clause Review for Calendar Year 2015

On September 8, 2016, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2015, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. A hearing in this Cause will be held on March 30, 2017.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates.

At December 31, 2016 and 2015, OG&E had regulatory assets of $526.6 million and $448.7 million, respectively, and regulatory liabilities of $312.0 million and $342.4 million, respectively. See Note 1 for a further discussion.

Management continuously monitors the future recoverability of regulatory assets. When, in management's judgment, future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OG&E were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Rate Structures

Oklahoma

OG&E's standard tariff rates include a cost-of-service component (including an authorized return on capital) plus a fuel adjustment clause mechanism that allows OG&E to pass through to customers the actual cost of fuel and purchased power.

OG&E offers several alternate customer programs and rate options. Under OG&E's Smart Grid enabled SmartHours programs, "time-of-use" and "variable peak pricing" rates offer customers the ability to save on their electricity bills by shifting some of the electricity consumption to off-peak times when demand for electricity and costs are at their lowest. The guaranteed flat bill option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set monthly price for an entire year. Another tariff rate option provides a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Oklahoma retail customers. OG&E's ownership and access to wind and solar resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. Another program being offered to OG&E's commercial and industrial customers is a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis when OG&E's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required. OG&E also offers certain qualifying customers "day-ahead price" and "flex price" rate options which allow participating customers to adjust their electricity consumption based on price signals received from OG&E. The prices for the "day-ahead price" and "flex price" rate options are based on OG&E's projected next day hourly operating costs.

OG&E also has the Public Schools-Demand and Public Schools Non-Demand rate classes that provide OG&E with flexibility to provide targeted programs for load management to public schools and their unique usage patterns. OG&E also provides service level, seasonal and time period fuel charge differentiation that allows customers to pay fuel costs that better reflect the underlying costs of providing electric service. Lastly, OG&E has a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

The previously discussed rate options, coupled with OG&E's other rate choices, provide many tariff options for OG&E's Oklahoma retail customers. The revenue impacts associated with these options are not determinable in future years because customers may choose to remain on existing rate options instead of volunteering for the alternative rate option choices. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options.

Arkansas

OG&E's standard tariff rates include a cost-of service component (including an authorized return on capital) plus an energy cost recovery mechanism that allows OG&E to pass through to customers the actual cost of fuel and purchased power. OG&E offers several alternate customer programs and rate options. The "time-of-use" and "variable peak pricing" tariffs allow participating customers to save on their electricity bills by shifting some of the electricity consumption to off-peak times when demand for electricity is lowest. A second tariff rate option provides a "renewable energy" resource to OG&E's Arkansas retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Arkansas retail customers. OG&E's ownership and access to wind resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. OG&E offers its commercial and industrial customers a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis and receive a billing credit when OG&E's system conditions merit curtailment action. OG&E offers certain qualifying customers a "day-ahead price" rate option which allows participating customers to adjust their electricity consumption based on a price signal received from OG&E. The day-ahead price is based on OG&E's projected next day hourly operating costs.

Fuel Supply and Generation

In 2016, 48.0 percent of OG&E-generated energy was produced by coal-fired units, 45.3 percent by natural gas-fired units and 6.7 percent by wind-powered units. Of OG&E's 6,667 total MWs of generation capability reflected in the table under Item 2. Properties, 3,650 MWs, or 54.7 percent, are from natural gas generation, 2,568 MWs, or 38.5 percent, are from coal generation and 449 MWs, or 6.8 percent, are from wind generation. Over the last five years, the weighted average cost of fuel used, by type, was as follows:

Year ended December 31 *(In cents/Kilowatt-Hour)*	**2016**	2015	2014	2013	2012
Natural gas	**2.488**	2.529	4.506	3.905	2.930
Coal	**2.213**	2.187	2.152	2.273	2.310
Weighted average	**2.199**	2.196	2.752	2.784	2.437

The increase in the weighted average cost of fuel in 2016 as compared to 2015 was primarily due to higher coal prices. The decrease in the weighted average cost of fuel in 2015 as compared to 2014 was primarily due to lower natural gas prices. The decrease in the weighted average cost of fuel in 2014 as compared to 2013 was primarily due to less natural gas used, partially offset by higher natural gas prices. The increase in the weighted average cost of fuel in 2013 as compared to 2012 was primarily due to higher gas prices. These fuel costs are recovered through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

OG&E participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations, and determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

Coal

OG&E's coal-fired units, with an aggregate capability of 2,568 MWs, are designed to burn low sulfur western sub-bituminous coal. The combination of all coal has a weighted average sulfur content of 0.24 percent. Based on the average sulfur content and EPA-certified data, OG&E's coal units have an approximate emission rate of 0.5 lbs of SO_2 per MMBtu.

For 2017, OG&E has acquired 100 percent of its forecasted annual coal usage via existing inventory and purchase contracts that expire in December 2017. In 2016, OG&E purchased 5.5 million tons of coal from various Wyoming suppliers. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" for a discussion of environmental matters which may affect OG&E in the future, including its utilization of coal.

Natural Gas

As a participant in the SPP Integrated Marketplace, OG&E now purchases a relatively small percentage of its natural gas supply through long-term agreements. Alternatively, OG&E relies on a combination of call natural gas agreements, whereby OG&E has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace.

Wind

OG&E's current wind power portfolio includes the following, in addition to the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms owned by OG&E: (i) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (ii) access to up to 152 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (iii) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2031 and (iv) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

Solar

In 2015, OG&E placed its first solar plant in service. The plant consists of two separate solar farms and is located in Oklahoma City, on the site of the Mustang generating facility. The Mustang solar plant has a maximum capacity of 2.5 MWs and consists of almost 10,000 photovoltaic panels.

OG&E expects to begin construction on 10 MWs of new solar farms in 2017. OG&E will evaluate the need to build additional solar plants, based on customer demand, cost, and reliability.

Safety and Health Regulation

OG&E is subject to a number of Federal and state laws and regulations, including OSHA, the EPA and comparable state statutes, whose purpose is to protect the safety and health of workers.

In addition, the OSHA Hazard Communication Standard, the EPA Emergency Planning and Community Right-to-Know regulations under Title III of the Federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials stored, used or produced in OG&E's operations and that this information be provided or made available to employees, state and local government authorities and citizens. OG&E believes that it is in material compliance with all applicable laws and regulations relating to worker safety and health.

NATURAL GAS MIDSTREAM OPERATIONS - ENABLE MIDSTREAM PARTNERS

Overview

Enable is a publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. Enable serves current and emerging production areas in the United States, including several unconventional shale resource plays and local and regional end-user markets in the United States. Enable's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Enable's gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to its producer customers. Enable's transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to its producer, power plant, LDC and industrial end-user customers.

Enable's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Enable's crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. Enable's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma and an investment in SESH, a pipeline extending from Louisiana to Alabama.

Enable was formed on May 1, 2013, to own and operate the midstream businesses of the Company and CenterPoint. As of December 31, 2016, Enable's portfolio of energy infrastructure assets included approximately 12,900 miles of gathering pipelines, 14 major processing plants with approximately 2.5 Bcf/d of processing capacity, approximately 7,800 miles of interstate pipelines (including SESH), approximately 2,200 miles of intrastate pipelines and eight natural gas storage facilities providing approximately 85.0 Bcf of storage capacity.

The following table shows the components of Enable's gross margin for the year ended December 31, 2016.

	Fee-Based			
	Demand/Commitment/Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2016				
Gathering and Processing Segment	34%	44%	22%	100%
Transportation and Storage Segment	93%	5%	2%	100%
Partnership Weighted Average	59%	28%	13%	100%

Gathering and Processing

Enable owns and operates substantial natural gas and crude oil gathering and natural gas processing assets in five states. Enable's gathering and processing operations consist primarily of natural gas gathering and processing assets serving the Anadarko, Arkoma and Ark-La-Tex Basins and crude oil gathering assets serving the Williston Basin. Enable provides a variety of services to the active producers in its operating areas, including gathering, compressing, treating, and processing natural gas, fractionating NGLs, and gathering crude oil and produced water.

Natural Gas Gathering and Processing. The following table sets forth certain information regarding Enable's gathering and processing assets as of or for the year ended December 31, 2016:

Asset/Basin	Approximate Length (miles)	Approximate Compression (Horsepower)	Average Gathered Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (MBbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	8,000	710,900	1.65	11	1,845	65.19	4.8
Arkoma Basin	2,900	134,500	0.62	1	60	4.86	1.4
Ark-La-Tex Basin(A)	1,700	146,700	0.86	2	545	8.65	0.7
Total	12,600	992,100	3.13	14	2,450	78.70	6.9

(A) Ark-La-Tex Basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Enable's gathering assets include more than 12,600 miles of natural gas gathering pipelines as of December 31, 2016. Enable's natural gas gathering systems consist of networks of pipelines that collect natural gas from points at or near its customers' wells for delivery to plants for processing or pipelines for transportation. Natural gas is moved from the receipt points to the delivery points on Enable's gathering systems by the use of compression.

Enable's natural gas processing assets included 14 natural gas processing plants with 2,450 MMcf/d of inlet capacity as of December 31, 2016. Natural gas is comprised primarily of methane, but at the wellhead, natural gas may contain varying amounts of NGLs. Enable's processing plants recover NGLs from natural gas and primarily deliver NGLs and natural gas to pipelines for transportation.

Crude Oil Gathering. As of December 31, 2016, Enable had approximately 175 miles of crude oil gathering pipelines and approximately 160 miles of produced water gathering pipelines in the Bakken Shale of the Williston Basin. Enable's crude oil gathering systems have a combined design capacity of 49.5 MBbl/d and as of December 31, 2016, Enable had 0.2 million gross acres dedicated under a crude oil gathering agreement. For the year ended December 31, 2016, Enable had an average daily throughput of 25.0 MBbl/d of crude oil and an average daily throughput of 6.0 MBbl/d of produced water on Enable's Bakken Shale gathering system.

Enable's Bakken Shale crude oil gathering assets are located in Dunn, McKenzie, Williams and Mountrail Counties in North Dakota. These systems were designed and built to serve the crude oil production of XTO Energy, Inc. in the area that they serve. On Enable's systems, crude oil is received on crude oil gathering pipelines near its customer's wells for delivery to third party transportation pipelines, and produced water is received by produced water gathering pipelines for delivery to third party disposal wells. Enable does not take title to crude oil or produced water gathered and it does not own or operate produced water disposal wells.

Delivery Points. Natural gas that is gathered, and when applicable, processed, is typically redelivered to Enable's customers at interconnections with transportation pipelines. Enable's gathering lines interconnect with both its interstate and intrastate pipelines, as well as other interstate and intrastate pipelines, including the Acadian, ANR, ETC Tiger, Gulf Crossing, Gulf South, NGPL, Northern Natural, Panhandle Eastern, Regency, Southern Natural Gas, Tennessee Gas and Texas Eastern Transmission pipelines. These connections provide producers with access to a variety of natural gas market hubs.

Crude oil gathered on Enable's Bakken Shale gathering systems in Dunn and McKenzie Counties is redelivered to its customers on the BakkenLink Pipeline, which provides access to rail transportation. Crude oil gathered on Enable's Bakken Shale gathering systems in Williams and Mountrail Counties is redelivered to its customers on the Enbridge North Dakota Pipeline, which provides interstate transportation from North Dakota to Minnesota. Enable anticipates constructing interconnections between its gathering systems and other pipelines that will provide access to the Dakota Access Pipeline during 2017.

Enable typically purchases the NGLs produced at its processing plants and most of the NGLs are delivered into third-party pipelines and transported to Conway, Kansas, or Mont Belvieu, Texas, where the NGLs are sold under contract or on the spot market. At Enable's Cox City, Calumet and Wetumka plants, it operates depropanizers that allow Enable to extract propane from the NGL stream and sell propane to local markets. Additionally, Enable operates a fractionator at its Waskom plant and sells ethane, propane, butane and natural gasoline to local markets.

Customers. Enable generates revenues from producers in the basins in which it operates. For the year ended December 31, 2016, Enable's top natural gas gathering and processing customers by gathered volumes were Continental Resources, Inc., Vine Oil and Gas, GeoSouthern Energy Corporation, XTO Energy Inc., Apache Corporation, Tapstone Energy LLC , affiliates of Chesapeake Energy Corporation, BP America Production Company, Covey Park Energy LLC and Marathon Oil Company. For the year ended December 31, 2016, Enable's top ten natural gas producer customers accounted for approximately 66 percent of its gathered natural gas volumes.

Enable's Bakken Shale gathering systems serve XTO Energy Inc. The rates and terms of service on Enable's Bakken Shale crude oil gathering systems are regulated by the FERC under the Interstate Commerce Act, but Enable's Bakken Shale produced water gathering systems are not FERC regulated. As of December 31, 2016, XTO Energy Inc. was Enable's only customer on these systems.

Contracts. Enable's contracts typically provide for natural gas and crude oil gathering services that are fee-based and for natural gas processing arrangements that are fee-based, or percent-of-liquids, percent-of-proceeds or keep-whole based. For the year ended December 31, 2016, 46 percent, 46 percent and eight percent of Enable's inlet volumes were under processing arrangements that were fee-based, percent-of-proceeds or percent-of-liquids, and keep-whole, respectively. For the year ended December 31, 2016, 78 percent of Enable's gathering and processing gross margin was fee-based, and the remaining 22 percent of its gathering and processing gross margin was primarily from sales of commodities, including natural gas, NGLs, and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements.

In lean gas areas, such as the lean gas areas of the eastern Arkoma Basin and the Haynesville Shale of the Ark-La-Tex Basin, some of Enable's natural gas gathering contracts contain minimum volume commitments from Enable's customers. In addition, a portion of the crude oil gathered by Enable's crude oil gathering system is under a contract with a minimum volume commitment. Under a minimum volume commitment a customer agrees to either deliver a minimum volume of natural gas or crude oil to Enable's system for service or pay the service fees for the minimum volume of natural gas or crude oil regardless of whether or not the minimum volume of natural gas or crude oil is delivered. Enable calls any payment for the difference between the volume gathered and the minimum volume committed a shortfall payment. Some of Enable's contracts provide its customers the option to elect to pay a higher gathering fee over the remaining term of the contract in lieu of making a shortfall payment. For the year ended December 31, 2016, 31 percent of Enable's gathering and processing gross margin was attributable to natural gas gathering contracts with minimum volume commitments, which as of December 31, 2016 had volume commitment-weighted average remaining terms of 4.6 years. Of this gross margin, 62 percent was attributable to shortfall payments. For the year ended December 31, 2016, three percent of Enable's gathering and processing gross margin was attributable to a crude oil gathering contract with a minimum volume commitment and a remaining term of 12.2 years; however, if the customer ships in excess of the minimum volume, this volume commitment could end before the expiration of the contract term. Of this gross margin, none was attributable to shortfall payments.

For Enable's gathering and processing contracts that do not have minimum volume commitments, it strives to obtain acreage dedications. Under an acreage dedication, a customer agrees to deliver all of the natural gas or crude oil produced from a given area to Enable's system for gathering, and, if applicable, processing. As of December 31, 2016, Enable had 6.9 million gross acres dedicated under natural gas gathering agreements with a volume-weighted average remaining term of 5.9 years and 0.2 million gross acres dedicated under a crude oil gathering agreement with a remaining term of 14.2 years.

Competition. Competition to gather and process natural gas is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Enable's gathering and processing systems compete with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. In the process of selling NGLs, Enable competes against other natural gas processors extracting and selling NGLs. Enable's primary competitors are other midstream companies who are active in the regions where it operates.

Competition to gather crude oil and produced water is primarily a function of rates, terms of service, system reliability, construction cycle time and prices at the wellhead. The rates and terms of service of Enable's crude oil gathering, but not its produced water gathering, are FERC regulated. Enable's Bakken gathering systems compete with other gatherers, including those affiliated with producers and other midstream companies.

Seasonality. While the results of Enable's gathering and processing segment are not materially affected by seasonality, from time to time its operations and construction of assets can be impacted by inclement weather.

Transportation and Storage

Enable owns and operates interstate and intrastate transportation and storage systems across nine states. Enable's transportation and storage systems consist primarily of its interstate systems, EGT and MRT, its intrastate system, EOIT and its investment in SESH. Enable's transportation and storage assets transport natural gas from areas of production and interconnected pipelines to power plants, LDCs and industrial end users as well as interconnected pipelines for delivery to additional markets. Enable's transportation and storage assets also provide facilities where natural gas can be stored by customers.

The following table sets forth certain information regarding Enable's transportation and storage assets as of December 31, 2016:

Asset	Length (miles)	Compression (Horsepower)	Average Throughput (TBtu/d)	Transportation Capacity (A) (Bcf/d)	Transportation Firm Contracted Capacity (Bcf/d)	Storage Capacity (Bcf)	Storage Firm Contracted Capacity (Bcf/d)
EGT	5,900	381,900	2.5	6.5	5.42	29.5	22.92
MRT	1,600	118,600	0.7	1.7	1.62	31.5	28.77
EOIT	2,200	216,200	1.7 (B)	— (B)	—	24.0	12.25
Subtotal	9,700	716,700	4.9	8.2	7.04	85.0	63.94
SESH	290	107,800	—	1.1 (C)	—	—	—
Total	9,990	824,500	4.9	9.3	7.04	85.0	63.94

(A) Actual volumes transported per day may be less than total firm contracted capacity based on demand.
(B) Enable's EOIT pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits its ability to determine an overall system capacity. During the year ended December 31, 2016, the peak daily throughput was 2.3 TBtu/d or, on a volumetric basis, 2.3 Bcf/d.
(C) SESH has 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

Enable's transportation and storage assets were designed and built to serve large natural gas and electric utilities in its areas of operation. In addition, Enable's transportation and storage assets serve natural gas producers, industrial end users and natural gas marketers. For the year ended December 31, 2016, Enable's top transportation and storage customers by revenue were affiliates of CenterPoint, Spire Inc., XTO Energy Inc., American Electric Power Co., the Company, Continental Resources, Inc, Chesapeake Energy Corporation, Midcontinent Express Pipeline LLC, EOG Resources, Inc. and Entergy Corporation.

Enable's transportation assets include approximately 10,000 miles of transportation pipelines in Texas, Oklahoma, Arkansas, Louisiana, Kansas and Missouri, providing access to natural gas supplies from the Anadarko, Arkoma and Ark-La-Tex Basins to natural gas consuming markets in the Southeastern, Northeastern and Midwestern United States. Enable's storage assets, as of December 31, 2016, provide a combined capacity of 85.0 Bcf with 2.0 Bcf/d of aggregate maximum withdrawal capacity from seven storage facilities in Oklahoma, Louisiana, Illinois and from its undivided 1/12th interest in the Bistineau Storage Facility in Louisiana. Gulf South owns an undivided 9/12th interest in, and operates, the Bistineau Storage Facility. In addition, Enable has contracted for 3.3 Bcf of firm storage capacity in Cardinal’s Perryville and Arcadia salt cavern storage facilities.

Enable's transportation and storage assets are comprised of three categories: (1) interstate transportation and storage, (2) intrastate transportation and storage and (3) Enable's investment in SESH.

Interstate Transportation and Storage

Enable's interstate transportation and storage business consists of EGT and MRT. As interstate pipelines, EGT and MRT are subject to regulation as natural gas companies by FERC under the Natural Gas Act of 1938.

EGT

EGT provides natural gas transportation and storage services primarily to customers in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas. In addition to 5,900 miles of interstate pipelines with capacity of 6.5 Bcf/d, EGT has two underground natural gas storage facilities in Oklahoma and one underground natural gas storage facility in Louisiana, which, as of December 31, 2016, operate at a combined capacity of 29.5 Bcf with 739 MMcf/d of aggregate maximum withdrawal capacity.

Customers. EGT primarily serves LDCs owned by CenterPoint, producers in key plays in the Mid-continent, power plants, other LDCs and industrial end-users. EGT’s customer are primarily located in Arkansas, Louisiana, Oklahoma and Texas. For the year ended December 31, 2016, approximately 25 percent of EGT's service revenue was attributable to contracts with LDCs owned by CenterPoint with a volume-weighted average contract life of 4.1 years. In addition to the CenterPoint LDCs, EGT’s other major customers include XTO Energy Inc., Continental Resources, Inc. and American Electric Power Co.

Contracts. Although EGT has established maximum rates for interstate transportation and storage services as required by the FERC, EGT is authorized to enter into negotiated rate and discounted rate agreements with its customers. EGT’s services are typically provided under firm, fee-based, transportation and storage agreements. For the year ended December 31, 2016, approximately 59 percent of Enable's transportation and storage gross margin was derived from EGT’s firm contracts, 83 percent of EGT’s transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 2.8 years, and 78 percent of EGT’s storage capacity was under firm contracts with a volume-weighted average remaining contract life of 4.2 years. The primary terms of EGT’s firm transportation and storage contracts with the CenterPoint LDCs will begin to expire in 2018, with the majority of the contracts expiring in 2021.

Seasonality. EGT provides gas transmission delivery services to LDCs owned by CenterPoint in Arkansas, Louisiana, Oklahoma and Texas. Customer demand for natural gas on EGT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, EGT experiences seasonal impacts associated with storage spreads and basis spreads on interconnected pipelines, as well as power plant demand.

Competition. EGT competes with a variety of other interstate and intrastate pipelines across Texas, Oklahoma, Arkansas and Louisiana. Enable's management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service. EGT provides both flexibility and reliability of service with access to multiple sources of supply in the Anadarko, Arkoma and Ark-La-Tex Basins and access to multiple markets in the Midwest, Northeast and Southeast through interconnections with other pipelines. EGT’s interconnections with other pipelines are primarily at Enable's Perryville Hub.

MRT

MRT provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois. In addition to 1,600-miles of interstate pipelines with capacity of 1.7 Bcf/d, MRT has one underground natural gas storage facility in Louisiana and one underground natural gas storage facility in Illinois, which, as of December 31, 2016, operate at a combined capacity of 31.5 Bcf with 620 MMcf/d of aggregate maximum withdrawal capacity.

Customers. MRT primarily serves Laclede Gas Company, the St. Louis LDC owned by Spire Inc. For the year ended December 31, 2016, 59 percent of MRT's service revenue was attributable to Spire Inc. under contracts with a volume-weighted average contract life of 2.3 years. MRT’s other customers include utilities and industrial end users. MRT’s customers are primarily located in Arkansas, Missouri and Illinois.

Contracts. MRT’s services are typically provided under firm, fee-based transportation and storage agreements, with rates and terms of service regulated by the FERC. For the year ended December 31, 2016, approximately 14 percent of Enable's transportation and storage gross margin was derived from MRT’s firm contracts, 95 percent of MRT’s transportation capacity was under firm contracts with a volume-weighted average remaining contract life of 2.5 years and 91 percent of MRT’s storage capacity was under firm contracts with a volume-weighted average remaining contract life of 1.4 years. MRT’s firm transportation and storage contracts with Spire Inc. are scheduled to expire in 2018 and 2020.

Seasonality. Customer demand for natural gas on MRT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. In addition, MRT experiences seasonal impacts associated with storage spreads and basis spreads on market-based pipelines.

Competition. MRT competes with various intrastate pipelines providing natural gas to the St. Louis market. In addition, MRT, from time-to-time, competes with potential projects to connect one or more third party interstate pipelines to the St. Louis market, such as the proposed Spire Inc. STL Pipeline for which a notice of application was filed on February 6, 2017 with the FERC. Enable's management views the principal elements of competition among pipelines as rates, terms of service, flexibility and reliability of service. MRT, through its interconnections with a variety of interstate and intrastate pipelines and its access to supply from a variety of producing basins, provides its customers with access to a variety of natural gas supply sources.

Intrastate Transportation and Storage

Enable's intrastate transportation and storage assets consist primarily of EOIT. EOIT provides transportation and storage services in Oklahoma. Enable's EOIT system delivers natural gas from the Arkoma and Anadarko Basins, including growth areas in the Cana Woodford, Granite Wash, Cleveland, Tonkawa, South Central Oklahoma Oil Province, Sooner Trend Anadarko Basin Canadian and Kingfisher Counties, and Mississippi Lime Shale plays in western Oklahoma and the Texas Panhandle, to utilities and industrial end users connected to EOIT and to interstate and intrastate pipelines interconnected with EOIT. EOIT had 1.72 TBtu/d of average daily throughput for the year ended December 31, 2016. In addition to the 2,200 miles of intrastate pipelines, EOIT has two underground natural gas storage facilities in Oklahoma, which, as of December 31, 2016 operate at a combined capacity of 24 Bcf with 605 MMcf/d of aggregate maximum withdrawal capacity. Enable's intrastate transportation also includes a 20-mile intrastate pipeline in Illinois.

Customers. EOIT’s customers include Oklahoma’s two largest electric utilities, OG&E and Public Service Company of Oklahoma, an affiliate of American Electric Power Co. For the year ended December 31, 2016, approximately seven percent of Enable's total transportation and storage gross margin was attributable to a firm contract with its affiliate OG&E, and approximately three percent of Enable's transportation and storage gross margin was attributable to a firm contract with Public Service Company of Oklahoma. Enable's transportation agreement with OG&E extends through April 30, 2019, and will remain in effect year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. Enable's transportation agreement with Public Service Company of Oklahoma is on a one-year renewal term and has been extended through December 31, 2017. EOIT’s customers also include other electric generators, LDCs, Arkoma and Anadarko Basin producers and industrial end users.

Contracts. EOIT provides fee-based firm and interruptible transportation and storage services on both an intrastate basis and, pursuant to Section 311 of the Natural Gas Policy Act of 1978, on an interstate basis. For the year ended December 31, 2016, approximately 20 percent of Enable's transportation and storage gross margin was derived from EOIT’s firm contracts, with a volume-weighted average remaining contract life of 4.9 years.

Seasonality. EOIT provides gas transmission delivery services to the majority of OG&E’s and all of PSO’s natural gas-fired electric generation facilities in Oklahoma. Customer demand for natural gas transportation and storage services on EOIT is usually greater during the summer, primarily due to demand by natural gas-fired power plants to serve residential and commercial electricity requirements.

Competition. EOIT competes with a variety of interstate and intrastate pipelines in providing transportation and storage services in Oklahoma, including competing against several pipelines with which EOIT interconnects. Enable's management views competition in the transportation and storage market as primarily a function of rates, terms of services, flexibility and reliability of service. EOIT’s integrated transportation and storage system allows Enable to provide load following service to natural gas-fired power plants to allow the power plants the ability to regulate generation and meet the instantaneous changes in customer demand for electricity.

Enable's Investment in SESH

SESH is an approximately 290-mile interstate pipeline that provides transportation services in Louisiana, Mississippi, and Alabama. Enable owns a 50 percent interest in SESH and provides field operations for the pipeline. Spectra Energy Partners, LP owns the remaining 50 percent interest in SESH and provides gas control and commercial operations for the pipeline. As of December 31, 2016, SESH had 1.09 Bcf/d of transportation capacity from Perryville, Louisiana to its endpoint in Mobile County, Alabama.

Customers and Contracts. SESH’s customers are companies that generate electricity for the Florida power market. The rates charged by SESH for interstate transportation services are regulated by the FERC. SESH’s transportation services are typically provided under firm, fee-based negotiated rate agreements. SESH's transportation contracts have a volume-weighted average remaining contract life of 5.4 years.

Seasonality. SESH is generally not impacted by seasonality, SESH's load factor generally remains constant throughout the year.

Competition. SESH competes with other interstate and intrastate pipelines providing access to the Southeast power generation market. Enable's management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service.

ENVIRONMENTAL MATTERS

General

The activities of the Company are subject to numerous stringent and complex Federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways including the handling or disposal of waste material, future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards.

Under the Obama administration, the trend in environmental regulation was to place more restrictions and limitations on activities that may affect the environment. The Company is unable to predict what changes the Trump administration may have on proposed or existing environmental regulations. The Company cannot assure that future events, such as changes in existing laws, the promulgation of new laws or regulations, or the development or discovery of new facts or conditions will not cause it to incur significant costs.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2017 will be $241.3 million, of which $221.9 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2018 will be approximately $180.8 million, of which $161.6 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NO_X burners, Dry Scrubbers and gas conversions. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations" in this Form 10-K.

FINANCE AND CONSTRUCTION

Future Capital Requirements and Financing Activities

Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for a discussion of the Company's capital requirements.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2017 through 2021 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects. Estimated capital expenditures for Enable are not included in the table below.

(In millions)	2017	2018	2019	2020	2021
OG&E Base Transmission	$ 35	$ 30	$ 30	$ 30	$ 30
OG&E Base Distribution	195	175	175	175	175
OG&E Base Generation	40	75	75	75	75
OG&E Other	35	25	25	25	25
Total Base Transmission, Distribution, Generation and Other	305	305	305	305	305
OG&E Known and Committed Non-Base Projects:					
Transmission Projects:					
Other Regionally Allocated Projects (A)	50	20	20	20	20
Large SPP Integrated Transmission Projects (B) (C)	155	20	—	—	—
Total Transmission Projects	205	40	20	20	20
Other Projects:					
Solar	20	—	—	—	—
Environmental - low NO_X burners (D)	15	—	—	—	—
Environmental - Dry Scrubbers (D)	160	95	15	—	—
Combustion turbines - Mustang	170	35	—	—	—
Environmental - natural gas conversion (D)	20	25	25	—	—
Allowance of funds used during construction and ad valorem taxes	55	40	5	—	—
Total Other Projects	440	195	45	—	—
Total Known and Committed Non-Base Projects	645	235	65	20	20
Total	$ 950	$ 540	$ 370	$ 325	$ 325

(A) Typically 100kV to 299kV projects. Approximately 30 percent of revenue requirement allocated to SPP members other than OG&E.
(B) Typically 300kV and above projects. Approximately 85 percent of revenue requirement allocated to SPP members other than OG&E.

(C) Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Integrated Transmission Project	30 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation. $5.0 million of the estimated cost has been spent prior to 2017.	$45	Late 2017
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation and construction of the Mathewson substation on this transmission line. $50.0 million of the estimated cost associated with the Mathewson to Cimarron line and substations went into service in 2016; $55.0 million has been spent prior to 2017.	$185	Mid 2018

(D) Represent capital costs associated with OG&E’s ECP to comply with the EPA’s MATS and Regional Haze Rule. More detailed discussion regarding Regional Haze Rule and OG&E’s ECP can be found in Note 14 and under "Environmental Laws and Regulations" within "Management's Discussion and Analysis of Financial Condition and Results of Operations" under Part II, Item 7 of this Form 10-K.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets, will be evaluated based upon their impact upon achieving the Company's financial objectives.

Pension and Postretirement Benefit Plans

During 2016, the Company made a $20.0 million contribution to its Pension Plan. During 2015, the Company did not make any contributions to its Pension Plan. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2017. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a discussion of the Company's pension and postretirement benefit plans.

Common Stock Dividends

At the Company's September 2016 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.30250 per share from $0.27500 per share effective in October 2016. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a further discussion.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. The Company has revolving credit facilities totaling in the aggregate $1,150.0 million. These bank facilities can also be used as letter of credit facilities. As of December 31, 2016, the Company had $236.2 million in short-term debt compared to no balance at December 31, 2015. The average balance of short-term debt in 2016 was $216.7 million at a weighted-average interest rate of 0.79 percent. The maximum month-end balance of short-term debt in 2016 was $355.6 million. At December 31, 2016, the Company had $912.0 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2017 and ending December 31, 2018. At December 31, 2016, the Company had $0.3 million in cash and cash equivalents. See Note 10 for a discussion of the Company's short-term debt activity.

In December 2011, the Company and OG&E entered into unsecured revolving credit agreements in the aggregate of $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E) which expire in December 2018. The Company and OG&E expect to replace the existing agreements with new revolving credit agreements during 2017, under terms and conditions generally similar to the existing agreements.

Expected Issuance of Long-Term Debt

OG&E expects to issue $300.0 million of long-term debt during the first half of 2017, depending on market conditions, to fund capital expenditures, to repay short or long-term borrowings and for general corporate purposes.

Common Stock

The Company does not expect to issue any common stock in 2017 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 8 for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable Limited Partnership Agreement, Enable made distributions of $141.2 million, $139.3 million and $143.7 million during the years ended December 31, 2016, 2015 and 2014.

EMPLOYEES

The Company had 2,453 employees at December 31, 2016, of which 158 are seconded to Enable.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 22, 2017:

Name	Age	Title
Sean Trauschke	49	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp.
E. Keith Mitchell	54	Chief Operating Officer - OG&E
Stephen E. Merrill	52	Chief Financial Officer - OGE Energy Corp.
Scott Forbes	59	Controller and Chief Accounting Officer - OGE Energy Corp.
Patricia D. Horn	58	Vice President - Governance and Corporate Secretary - OGE Energy Corp.
Jean C. Leger, Jr.	58	Vice President - Utility Operations - OG&E
Kenneth R. Grant	52	Vice President- Sales and Marketing - OG&E
Cristina F. McQuistion	52	Vice President - Chief Information Officer - OG&E
Jerry A. Peace	54	Vice President- Integrated Resource Planning and Development - OG&E
Paul L. Renfrow	60	Vice President - Public Affairs and Corporate Administration - OGE Energy Corp.
William H. Sultemeier	49	General Counsel - OGE Energy Corp.
Charles B. Walworth	42	Treasurer - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Trauschke, Merrill, Forbes, Renfrow, Sultemeier, Walworth and Ms. Horn are also officers of OG&E. Each Executive Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareholders, currently scheduled for May 18, 2017.

Mr. Trauschke is a member of the Board of Directors of Enable GP, LLC, the general partner of Enable. Mr. Merrill will become a member of the Board of Directors of Enable GP, LLC on March 1, 2017.

The business experience of each of the Executive Officers of the Registrant for the past five years is as follows:

Name		Business Experience
Sean Trauschke	2015 - Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp.
	2014 - 2015:	President of OGE Energy Corp.
	2012 - 2014:	Vice President and Chief Financial Officer of OGE Energy Corp.
E. Keith Mitchell	2015 - Present:	Chief Operating Officer of OG&E
	2013 - 2015:	Executive Vice President and Chief Operating Officer of Enable Midstream Partners, LP
	2012 - 2013:	President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC
Stephen E. Merrill	2014 - Present:	Chief Financial Officer of OGE Energy Corp.
	2013 - 2014:	Executive Vice President of Finance and Chief Administrative Officer of Enable Midstream Partners, LP
	2012 - 2013:	Chief Operating Officer of Enogex LLC
Scott Forbes	2012 - Present:	Controller and Chief Accounting Officer of OGE Energy Corp.
Patricia D. Horn	2014 - Present:	Vice President - Governance and Corporate Secretary of OGE Energy Corp.
	2012 - 2014:	Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp.
	2012:	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp.
Jean C. Leger, Jr.	2012 - Present:	Vice President - Utility Operations of OG&E
Kenneth R. Grant	2016 - Present:	Vice President - Sales and Marketing of OG&E
	2015:	Vice President Marketing and Product Development of OG&E
	2013 - 2015:	Managing Director Tech Solutions & Ops of OG&E
	2012 - 2013:	Managing Director Customer Solutions of OG&E
Cristina F. McQuistion	2017 - Present:	Vice President - Chief Information Officer of OG&E
	2016 - 2017:	Vice President - Chief Information Officer and Utility Strategy of OG&E
	2014 - 2015:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OG&E
	2013 - 2014:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OGE Energy Corp. and OG&E
	2012 - 2013:	Vice President - Strategy and Performance Improvement of OGE Energy Corp. and OG&E
Jerry A. Peace	2016 - Present:	Vice President - Integrated Resource Planning and Development of OG&E
	2014 - 2015	Chief Generation Planning and Procurement Officer of OG&E
	2012 - 2014:	Chief Risk Officer of OGE Energy Corp.
Paul L. Renfrow	2014 - Present:	Vice President - Public Affairs and Corporate Administration of OGE Energy Corp.
	2012 - 2014:	Vice President - Public Affairs, Human Resources and Health & Safety of OGE Energy Corp.
William H. Sultemeier	2017 - Present:	General Counsel of OGE Energy Corp.
	2016:	Partner - Jones Day
	2012-2015:	Shareholder - Greenberg Traurig, LLP
Charles B. Walworth	2014 - Present:	Treasurer of OGE Energy Corp.
	2012 - 2014:	Assistant Treasurer of OGE Energy Corp.
	2012:	Senior Manager Finance of OGE Energy Corp.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

The Company's website address is *www.oge.com*. Through the Company's website under the heading "Investors," "Investor Relations," "SEC Filings," the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated into this Form 10-K and should not be considered a part of this Form 10-K.

Item 1A. Risk Factors.

In the discussion of risk factors set forth below, unless the context otherwise requires, the terms "we," "our" and "us" refer to the Company. In addition to the other information in this Form 10-K and other documents filed by us and/or our subsidiaries with the Securities and Exchange Commission from time to time, the following factors should be carefully considered in evaluating OGE Energy and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by or on behalf of us or our subsidiaries. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business operations.

REGULATORY RISKS

OG&E's profitability depends to a large extent on the ability to fully recover its costs from its customers in a timely manner and there may be changes in the regulatory environment that impair its ability to recover costs from its customers.

OG&E is subject to comprehensive regulation by several Federal and state utility regulatory agencies, which significantly influences its operating environment and its ability to fully recover its costs from utility customers. Recoverability of any under recovered amounts from OG&E's customers due to a rise in fuel costs is a significant risk. The utility commissions in the states where OG&E operates regulate many aspects of its utility operations including siting and construction of facilities, customer service and the rates that OG&E can charge customers. The profitability of the utility operations is dependent on OG&E's ability to fully recover costs related to providing energy and utility services to its customers in a timely manner. Any failure to obtain utility commission approval to increase rates to fully recover costs, or a delay in the receipt of such approval, could have an adverse impact on OG&E's results of operations. In addition, OG&E's jurisdictions have fuel adjustment clauses that permit OG&E to recover fuel costs through rates without a general rate case, subject to a later determination that such fuel costs were prudently incurred. If the state regulatory commissions determine that the fuel costs were not prudently incurred, recovery could be disallowed.

In recent years, the regulatory environments in which OG&E operates have received an increased amount of attention. It is possible that there could be changes in the regulatory environment that would impair OG&E's ability to fully recover costs historically paid by OG&E's customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. OG&E cannot assure that the OCC, APSC and the FERC will grant rate increases in the future or in the amounts requested, and they could instead lower OG&E's rates.

OG&E is unable to predict the impact on its operating results from future regulatory activities of any of the agencies that regulate OG&E. Changes in regulations or the imposition of additional regulations could have an adverse impact on OG&E's results of operations.

OG&E's rates are subject to rate regulation by the states of Oklahoma and Arkansas, as well as by a Federal agency, whose regulatory paradigms and goals may not be consistent.

OG&E is currently a vertically integrated electric utility. Most of its revenue results from the sale of electricity to retail customers subject to bundled rates that are approved by the applicable state utility commission.

OG&E operates in Oklahoma and western Arkansas and is subject to rate regulation by the OCC and the APSC, in addition to FERC regulation of its transmission activities and any wholesale sales. Exposure to inconsistent state and Federal regulatory standards may limit our ability to operate profitably. Further alteration of the regulatory landscape in which we operate, including a change in our authorized return on equity, may harm our financial position and results of operations.

Costs of compliance with environmental laws and regulations are significant and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations, consolidated financial position, or liquidity.

We are subject to extensive Federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

In response to recent regulatory and judicial decisions and international accords, emissions of greenhouse gases including, most significantly, CO_2 could be restricted in the future as a result of Federal or state legal requirements or litigation relating to greenhouse gas emissions. Additionally, international treaties or protocols could result in future additional reductions in the United States. In October 2015, the EPA issued standards for states to implement to control greenhouse gas emissions from existing electric generating units. A number of states, including Oklahoma, filed lawsuits against the EPA standards. In February 2016, the U.S. Supreme Court entered an order staying the implementation of these EPA standards. If the standards survive judicial review and are implemented as written, they could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Due to the pending litigation and the uncertainties in the state approaches, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time.

There is growing effort to initiate nuisance claims against power generators. The impact of these efforts on OG&E cannot be determined with certainty as this time.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations and historical industry operations practices. These activities are subject to stringent and complex Federal, state and local laws and regulations that can restrict or impact OG&E's business activities in many ways, such as restricting the way OG&E can handle or dispose of its wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. OG&E may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations."

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

OG&E's business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits and modernizing existing infrastructure as well as other initiatives. Significant portions of OG&E's facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations. OG&E currently provides service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates OG&E charges, it would not be able to recover the costs associated with its planned extensive investment. This could adversely affect OG&E's financial position and results of operations. While OG&E may seek to limit the impact of any denied recovery by attempting to reduce the scope of its capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

As of December 31, 2016, OG&E had incurred $208.7 million of construction work in progress on the Dry Scrubbers.

The regional power market in which OG&E operates has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses.

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority (but not ownership) of OG&E's transmission facilities to the SPP. The SPP has implemented regional day ahead and real-time markets for energy and operating reserves, as well as associated transmission congestion rights. Collectively the three markets operate together under the global name, SPP Integrated Marketplace. OG&E represents owned and contracted generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OG&E has not participated in the SPP Integrated Marketplace for any speculative trading activities. OG&E records the SPP Integrated Marketplace transactions as sales or purchases with results reported as Operating Revenues or Cost of Goods Sold in its Consolidated Financial Statements. OG&E's revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation of the SPP Integrated Marketplace by the FERC or the SPP.

Increased competition resulting from restructuring efforts could have a significant financial impact on us and consequently decrease our revenue.

We have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes have occurred and additional changes have been proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on us due to possible impairments of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on our consolidated financial position, results of operations and cash flows. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our consolidated financial position, results of operations or cash flows.

Events that are beyond our control have increased the level of public and regulatory scrutiny of our industry. Governmental and market reactions to these events may have negative impacts on our business, consolidated financial position, results of operations, cash flows and access to capital.

As a result of accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, public companies, including those in the regulated and unregulated utility business, have been under public and regulatory scrutiny and suspicion. The accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between companies and their independent auditors. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we are complying with all applicable laws and accounting standards, but it is difficult or impossible to predict or control what effect these types of events may have on our business, consolidated financial position, cash flows or access to the capital markets. It is unclear what additional laws or regulations may develop, and we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically. Any new accounting standards could affect the way we are required to record revenues, expenses, assets, liabilities and equity. These changes in accounting standards could lead to negative impacts on reported earnings or decreases in assets or increases in liabilities that could, in turn, affect our results of operations and cash flows.

We are subject to substantial utility and energy regulation by governmental agencies. Compliance with current and future utility and energy regulatory requirements and procurement of necessary approvals, permits and certifications may result in significant costs to us.

We are subject to substantial regulation from Federal, state and local regulatory agencies. We are required to comply with numerous laws and regulations and to obtain permits, approvals and certifications from the governmental agencies that regulate various aspects of our businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of these agencies.

In compliance with the Energy Policy Act of 2005, the FERC approved the NERC as the national energy reliability organization. The NERC is responsible for the development and enforcement of mandatory reliability and cyber security standards for the wholesale electric power system. OG&E's plan is to comply with all applicable standards and to expediently correct a violation should it occur. One of OG&E's regulators, NERC, has comprehensive regulations and standards related to the reliability and security of our operating systems, and is continuously developing additional mandatory compliance requirements for the utility industry. The increasing development of NERC rules and standards will increase compliance costs and our exposure for potential violations of these standards.

OPERATIONAL RISKS

Our results of operations may be impacted by disruptions beyond our control.

We are exposed to risks related to performance of contractual obligations by our suppliers. We are dependent on coal and natural gas for much of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short and long-term contracts. We have certain supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal and natural gas to us. The suppliers under these agreements may experience financial or technical problems that inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply coal and natural gas to us under certain circumstances, such as in the event of a natural disaster. Deliveries may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather and availability of equipment. Failure or delay by our suppliers of coal and natural gas deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers.

Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event such as a severe storm or generator or transmission facility outage on a neighboring system or the actions of a neighboring utility. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our consolidated financial position, results of operations and cash flows.

OG&E's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased purchase power costs.

OG&E owns and operates coal-fired, natural gas-fired, wind-powered and solar-powered generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- increased prices for fuel and fuel transportation as existing contracts expire;
- facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply;
- operator error or safety related stoppages;
- disruptions in the delivery of electricity; and
- catastrophic events such as fires, explosions, tornadoes, floods, earthquakes or other similar occurrences.

When unplanned maintenance work is required on power plants or other equipment, OG&E will not only incur unexpected maintenance expenses, but it may also have to make spot market purchases of replacement electricity that could exceed OG&E's costs of generation or be forced to retire a generation unit if the cost or timing of the maintenance is not reasonable and prudent. If OG&E is unable to recover any of these increased costs in rates, it could have a material adverse effect on our financial performance.

Changes in technology and regulatory policies may cause our generating facilities to be less competitive.

OG&E primarily generates electricity at large central facilities. This method typically results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations. OG&E's widespread use of Smart Grid technology allowing for two-way communications between the utility and its customers could enable the entry of technology companies into the interface between OG&E and its customers, resulting in unpredictable effects on our current business.

Increased deployment of renewable energy technologies could reduce utility electric sales, but would not reduce our need for ongoing investments in our infrastructure to reliably serve our customers. Continued utility infrastructure investment without increased electricity sales could cause increased rates for customers, potentially resulting in further reductions in electricity sales and reduced profitability.

Economic conditions could negatively impact our business and our results of operations.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital. Economic conditions may also impact the valuation of certain long-lived assets, including our investment in unconsolidated affiliates, that are subject to impairment testing, potentially resulting in impairment charges, which could have a material adverse impact on our results of operations.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which could impact the ability of our customers to pay timely, increase customer bankruptcies, and could lead to increased bad debt. If such circumstances occur, we expect that commercial and industrial customers would be impacted first, with residential customers following.

In addition, economic conditions, particularly budget shortfalls, could increase the pressure on Federal, state and local governments to raise additional funds by increasing corporate tax rates and/or delaying, reducing or eliminating tax credits, grants or other incentives that could have a material adverse impact on our results of operations and cash flows.

We are subject to financial risks associated with climate change.

Climate change creates financial risk. Potential regulation associated with climate change legislation could pose financial risks to the Company. In addition, to the extent that any climate change adversely affects the national or regional economic health through physical impacts or increased rates caused by the inclusion of additional regulatory imposed costs, CO_2 taxes or costs associated with additional regulatory requirements, the Company may be adversely impacted. A declining economy could adversely impact the overall financial health of the Company due to a lack of load growth and decreased sales opportunities. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

We are subject to cybersecurity risks and increased reliance on processes automated by technology.

In the regular course of our businesses, we handle a range of sensitive security and customer information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems such as theft or inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on our consolidated financial position, results of operations and cash flows.

OG&E operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, the technology systems are vulnerable to disability, failures or unauthorized access. Such failures or breaches of the systems could impact the reliability of OG&E's generation, transmission and distribution systems which may result in a loss of service to customers and also subject OG&E to financial harm due to the significant expense to repair security breaches or system damage. The implementation of OG&E's Smart Grid program further increases potential risks associated with cybersecurity attacks. Our generation and transmission systems are part of an interconnected system. Therefore, a disruption caused by the impact of a cybersecurity incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. If the technology systems were to fail or be breached and not recovered in a timely manner, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on its consolidated financial position, results of operations and cash flows.

Our security procedures, which include among others, virus protection software, cybersecurity and our business continuity planning, including disaster recovery policies and back-up systems, may not be adequate or implemented properly to fully address the adverse effect of cybersecurity attacks on our systems, which could adversely impact our operations.

We maintain property, casualty and cybersecurity insurance that may cover certain resultant physical damage or third-party injuries caused by potential cyber events. However, damage and claims arising from such incidents may exceed the amount of any insurance available and other damage and claims arising from such incidents may not be covered at all. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities or sustained military campaigns may adversely impact our consolidated financial position, results of operations and cash flows.

The long-term impact of terrorist attacks and the magnitude of the threat of future terrorist attacks on the electric utility and natural gas midstream industry in general, and on us in particular, cannot be known. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities or sustained military campaigns may affect our operations in unpredictable ways, including disruptions of supplies and markets for our products, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than existing insurance coverage.

Weather conditions such as tornadoes, thunderstorms, ice storms, wind storms, earthquakes and prolonged droughts, as well as seasonal temperature variations may adversely affect our consolidated financial position, results of operations and cash flows.

Weather conditions directly influence the demand for electric power. In OG&E's service area, demand for power peaks during the hot summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Unusually mild weather in the future could reduce our revenues, net income, available cash and borrowing ability. Severe weather, such as tornadoes, thunderstorms, ice storms, wind storms, earthquakes and prolonged droughts may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned, as described above, would be particularly burdensome during a peak demand period. In addition, prolonged droughts could cause a lack of sufficient water for use in cooling during the electricity generating process. Additionally, if climate change exacerbates physical changes in weather, operations may be impacted as discussed above.

FINANCIAL RISKS

Market performance, increased retirements, changes in retirement plan regulations and increasing costs associated with our Pension Plan, health care plans and other employee-related benefits may adversely affect our consolidated financial position, results of operations or cash flow.

We have a Pension Plan that covers a significant amount of our employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover a significant amount of our employees hired prior to February 1, 2000. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions with respect to the defined benefit retirement and postretirement plans have a significant impact on our results of operations and funding requirements. Based on our assumptions at December 31, 2016, we expect to make future contributions to maintain required funding levels. It has been our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. We may continue to make voluntary contributions in the future. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

If the employees who participate in the Pension Plan retire when they become eligible for retirement over the next several years, or if our plan experiences adverse market returns on its investments, or if interest rates materially fall, our pension expense and contributions to the plans could rise substantially over historical levels. The timing and number of employees retiring and selecting the lump-sum payment option could result in pension settlement charges that could materially affect our results of operations if we are unable to recover these costs through our electric rates. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our consolidated financial position and results of operations. Those factors are outside of our control.

In addition to the costs of our Pension Plan, the costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees, will continue to rise. The increasing costs and funding requirements with our Pension Plan, health care plans and other employee benefits may adversely affect our consolidated financial position, results of operations or liquidity.

Finally, the Company provides retirement benefits and retiree health care benefits to approximately 160 employees seconded to Enable. If the seconding agreement was terminated, and those employees were no longer employed by the Company, and lump sum payments were made to those employees, the Company would recognize a settlement or curtailment of the pension/retiree health care charges, which would increase expense at the Company by approximately $21.4 million. Settlement and curtailment charges associated with the Enable seconded employees are not reimbursable to the Company by Enable. The seconding agreement can be terminated by mutual agreement of the Company and Enable or solely by the Company upon 120 day notice.

We face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements.

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility industry. The median age of utility workers is significantly higher than the national average. Over the next three years, 38 percent of our current employees will meet the eligibility requirements to retire. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business.

We are a holding company with our primary assets being investments in our subsidiary and equity investments.

We are a holding company and thus our investments in our subsidiary and unconsolidated affiliate, accounted for under the equity method, are our primary assets. Substantially all of our operations are conducted by our subsidiary and unconsolidated affiliate. Consequently, our operating cash flow and our ability to pay our dividends and service our indebtedness utilizes the operating cash flow of our subsidiary and unconsolidated affiliate and the payment of funds by them to us in the form of dividends or distributions. At December 31, 2016, the Company and its subsidiary had outstanding indebtedness and other liabilities of $6.5 billion. Our subsidiary and unconsolidated affiliate are separate legal entities that have no obligation to pay any amounts due on our indebtedness or to make any funds available for that purpose, whether by dividends or otherwise. In addition, their ability to pay dividends to us depends on any statutory and contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiary or unconsolidated affiliate on their respective assets will generally have priority over our claims (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareholders.

In addition, as discussed above, OG&E is regulated by state utility commissions in Oklahoma and Arkansas as well as a Federal regulatory agency which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions or Federal regulatory agency attempt to impose restrictions on the ability of OG&E to pay dividends to us, it could adversely affect our ability to continue to pay dividends.

Certain provisions in our charter documents have anti-takeover effects.

Certain provisions of our certificate of incorporation and bylaws, as well as the Oklahoma corporation statute, may have the effect of delaying, deferring or preventing a change in control of the Company. Such provisions, including those regulating the nomination of directors, limiting who may call special stockholders' meetings and eliminating stockholder action by written consent, together with the possible issuance of preferred stock of the Company without stockholder approval, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire substantial amounts of our common stock or to launch other takeover attempts that a stockholder might consider to be in such stockholder's best interest.

We may be able to incur substantially more indebtedness, which may increase the risks created by our indebtedness.

The terms of the indentures governing our debt securities do not fully prohibit us or our subsidiaries from incurring additional indebtedness. If we are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we may be able to incur substantial additional indebtedness. If we incur additional indebtedness, the related risks that we and they now face may intensify.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships or limit our ability to obtain financing on favorable terms.

We cannot assure you that any of our current credit ratings or the ratings of our subsidiaries will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Our ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with our credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of our short-term borrowings, but a reduction in our credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require us to post collateral or letters of credit.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We have revolving credit agreements for working capital, capital expenditures, acquisitions and other corporate purposes. The levels of our debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our debt levels may limit our flexibility in responding to changing business and economic conditions.

We are exposed to the credit risk of our key customers and counterparties, and any material nonpayment or nonperformance by our key customers and counterparties could adversely affect our consolidated financial position, results of operations and cash flows.

We are exposed to credit risks in our generation, retail distribution and pipeline operations. Credit risk includes the risk that counterparties who owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

RISKS ASSOCIATED WITH OUR INVESTMENT IN ENABLE MIDSTREAM PARTNERS

The Company does not control Enable and therefore is not able to cause or prevent certain actions by Enable.

Enable has its own governing board, therefore, the Company is not able to exercise control over Enable. Accordingly, the Company is unable to cause or prevent certain actions by Enable.

A significant portion of our earnings and operating cash flows are based on the performance of Enable. If any of the following risks were to occur, our business, financial condition, results of operations or cash flows could be materially adversely affected.

Our operating cash flow is derived partially from cash distributions we receive from Enable.

Our operating cash flow is derived partially from cash distributions we receive from Enable. The amount of cash Enable can distribute on its units principally depends upon the amount of cash generated from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins it realizes with respect to the volume of natural gas, NGLs and crude oil that it handles;
- the prices of, levels of production of, and demand for natural gas, NGLs and crude oil;
- the volume of natural gas, NGLs and crude oil it gathers, compresses, treats, dehydrates, processes, fractionates, transports and stores;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- adverse effects of governmental and environmental regulation;
- the level of its operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash Enable will have available for distribution will depend on other factors, including:

- the level and timing of capital expenditures it makes;
- the cost of acquisitions;
- its debt service requirements and other liabilities;
- fluctuations in working capital needs;
- its ability to borrow funds and access capital markets;
- restrictions contained in its debt agreements;
- the amount of cash reserves established by its general partner;
- distributions paid on its Series A Preferred Units; and
- other business risks affecting its cash levels.

Enable's contracts are subject to renewal risk.

As contracts with Enable's existing suppliers and customers expire, Enable may have to negotiate extensions or renewals of those contracts or enter into new contracts with other suppliers and customers. Enable may be unable to extend or renew existing contracts or enter into new contracts on favorable commercial terms, if at all. Depending on prevailing market conditions at the time of an extension or renewal, gathering and processing customers with fee-based contracts may desire to enter into contracts under different fee arrangements. Approximately 87 percent of Enable's gross margin was generated from fee-based contracts during the year ended December 31, 2016. Likewise, Enable's transportation and storage customers may choose not to extend or renew expiring contracts based on the economics of the related areas of production. To the extent Enable is unable to renew or replace its expiring contracts on terms that are favorable to Enable, if at all, or successfully manage its overall contract mix over time, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Enable depends on a small number of customers for a significant portion of its gathering and processing services revenues and its transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of its gathering and processing or transportation and storage services and adversely affect its financial position, results of operations and ability to make cash distributions to us.

For the year ended December 31, 2016, 49 percent of Enable's gathered natural gas volumes were attributable to the affiliates of Continental Resources, Inc., Vine Oil and Gas, GeoSouthern Energy Corporation, XTO Energy Inc. and Apache Corporation and 51 percent of its transportation and storage service revenues were attributable to affiliates of CenterPoint, Spire Inc., XTO Energy Inc., American Electric Power Co., and the Company. The loss of all or even a portion of the gathering and processing or transportation and storage services for any of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us.

The businesses of Enable are dependent, in part, on the drilling and production decisions of others.

The businesses of Enable are dependent on the drilling and production of natural gas and crude oil. Enable has no control over the level of drilling activity in its areas of operation, or the amount of natural gas, NGL and crude oil reserves associated with wells connected to its systems. In addition, as the rate at which production from wells currently connected to its system naturally declines over time, its gross margin associated with those wells will also decline. To maintain or increase throughput levels on its gathering and transportation systems and the asset utilization rates at its natural gas processing plants, its customers must continually obtain new natural gas, NGL and crude oil supplies. The primary factors affecting its ability to obtain new supplies of natural gas, NGLs and crude oil and attract new customers to its assets are the level of successful drilling activity near its systems, its ability to compete for volumes from successful new wells and its ability to expand its capacity as needed. If Enable is not able to obtain new supplies of natural gas and crude oil to replace the natural decline in volumes from existing wells, throughput on its gathering, processing, transportation and storage facilities would decline, which could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us. Enable has no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of natural gas, NGLs and crude oil;
- demand for natural gas, NGLs and crude oil;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new natural gas, NGL and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, NGLs, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond its control. Because of these factors, even if new natural gas, NGL or crude oil reserves are known to exist in areas served by its assets, producers may choose not to develop those reserves. Declines in natural gas, NGL or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016. Sustained low natural gas, NGL or crude oil prices could also lead producers to shut in production from their existing wells. Sustained reductions in exploration or production activity in its areas of operation could lead to further reductions in the utilization of its systems, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

In addition, it may be more difficult to maintain or increase the current volumes on its gathering systems and its processing plants, as several of the formations in the unconventional resource plays in which Enable operates generally have higher initial production rates and steeper production decline curves than wells in more conventional basins. Should Enable determine that the economics of its gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, it may reduce such capital expenditures, which could cause revenues associated with these assets to decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require Enable to incur higher maintenance capital expenditures relative to throughput over time, which will reduce its distributable cash flow.

Because of these and other factors, even if new reserves are known to exist in areas served by its assets, producers may choose not to develop those reserves. Reductions in drilling activity would result in an inability to maintain the current levels of throughput on its systems and could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable’s industry is highly competitive, and increased competitive pressure could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable competes with similar enterprises in its respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Competitors include large energy companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil other than Enable. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enable provides to its customers. Excess pipeline capacity in the regions served by Enable's interstate pipelines could also increase competition and adversely impact the ability to renew or enter into new contracts with respect to available capacity when existing contracts expire. In addition, customers that are significant producers of natural gas or crude oil may develop their own gathering, processing, transportation and storage systems in lieu of using Enable. Enable’s ability to renew or replace existing contracts with customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and customers. Further, natural gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and storage services. All of these competitive pressures could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable derives a substantial portion of its gross margin from subsidiaries through which it holds a substantial portion of its assets.

Enable derives a substantial portion of its gross margin from, and holds a substantial portion of its assets through, its subsidiaries. As a result, it depends on distributions from its subsidiaries in order to meet its payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide Enable with funds for its payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit its subsidiaries’ ability to make payments or other distributions, and its subsidiaries could agree to contractual restrictions on its ability to make distributions.

The right by Enable to receive any assets of any subsidiary, and therefore the right of its creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary’s creditors, including trade creditors. In addition, even if Enable were a creditor of any subsidiary, its rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by them.

The amount of cash Enable has available for distribution to its limited partners depends primarily on its cash flow rather than on its profitability, which may prevent Enable from making distributions, even during periods in which it records net income.

The amount of cash Enable has available for distribution depends primarily upon its cash flow rather than on profitability. Profitability is affected by non-cash items but cash flow is not. As a result, Enable may make cash distributions during periods when it records losses for financial accounting purposes and may not make cash distributions during periods when it records net earnings for financial accounting purposes.

Enable is expected to pay a specified minimum quarterly distribution on its outstanding common and subordinated units, including those units that we own, to the extent it has sufficient cash from operations after establishment of cash reserves, payments of distributions on the Series A Preferred Units and payment of fees and expenses, including payments to its general partner and its affiliates. The principal difference between Enable’s common units and subordinated units is that in any quarter during the applicable subordination period, holders of the subordinated units are not entitled to receive any distribution until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution on common units from prior quarters. If Enable does not pay distributions on its subordinated units, its subordinated units will not accrue arrearages for those unpaid distributions.

Enable may not be able to recover the costs of its substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than it anticipates.

Enable's business plan calls for investments in capital improvements and additions. Capital expenditures could range from approximately $550 million to $700 million for the year ending December 31, 2017. For example, in the second quarter of 2016 Enable delayed the completion of the Wildhorse plant, a cryogenic processing facility that it plans to connect to its super-header system in Garvin County, Oklahoma. Enable also plans to construct natural gas gathering and compression infrastructure to support producer activity in its growth areas.

The construction of additions or modifications to Enable's existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond its control and may require the expenditure of significant amounts of capital, which may exceed estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel, labor shortages or weather or other delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner, if at all, or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. Moreover, revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if an existing pipeline is expanded or a new pipeline is constructed, the construction may occur over an extended period of time, and not receive any material increases in revenues or cash flows until the project is completed. In addition, Enable may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, the new facilities may not be able to achieve an expected investment return, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

In connection with its capital investments, Enable may engage a third party to estimate potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent Enable relies on estimates of future production in deciding to construct additions to its systems, those estimates may prove to be inaccurate due to numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to construction. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable, and it may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect Enable's financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable's financial position, results of operations and ability to make cash distributions to us could be negatively affected by adverse movements in the prices of natural gas, NGLs and crude oil depending on factors that are beyond its control. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, liquefied natural gas, NGLs and crude oil, actions taken by foreign natural gas and oil producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation. In early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. Both natural gas and crude oil prices increased moderately in the second half of 2016.

Enable's natural gas processing arrangements exposes it to commodity price fluctuations. In 2016, eight percent, 46 percent, and 46 percent of Enable's processing plant inlet volumes consisted of keep-whole arrangements, percent-of-proceeds or percent-of-liquids, and fee-based, respectively. Under a typical keep-whole arrangement, Enable processes raw natural gas, extracts the NGLs, replaces the extracted NGLs with a Btu equivalent amount of natural gas, delivers the processed and replacement natural gas to the producer, retains the NGLs, and sells the NGLs for its own account. If Enable is unable to sell the NGLs extracted for more than the cost of the replacement natural gas, the margins on its sale of goods will be negatively affected.

Under a typical percent-of-proceeds processing agreement, Enable purchases raw natural gas at a cost that is based on the amount of natural gas and NGLs contained in the raw natural gas. Enable then processes the raw natural gas, extracts the

NGLs, and sells the processed natural gas and NGLs for its own account. If Enable is unable to sell the processed natural gas and NGLs for more than the cost of the raw natural gas, the margins on its sale of goods will be negatively affected.

Under a typical percent-of-liquids processing arrangement and a typical fee-based arrangement, Enable purchases a portion of the raw natural gas that is equivalent to the amount of NGLs it contains, processes the raw natural gas, extracts the NGLs, returns the processed natural gas to the producer, and sells the NGLs for its own account. If Enable is unable to sell the processed natural gas and NGLs for more than the cost of raw natural gas, the margins on its sale of goods will be negatively affected.

At any given time, Enable's overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that it is a net buyer of natural gas) and a net long position in NGLs (meaning that it is a net seller of NGLs). As a result, its gross margin could be adversely impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

Enable's exposure to credit risks of its customers, and any material nonpayment or nonperformance by its key customers could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Some of Enable's customers may experience financial problems that could have a significant effect on its customers' creditworthiness. Severe financial problems encountered by its customers could limit Enable's ability to collect amounts owed to it, or to enforce performance of obligations under contractual arrangements. In addition, many of Enable's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of its customers’ liquidity and limit its customers ability to make payments or perform on obligations to Enable. Furthermore, some of Enable's customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to Enable. Financial problems experienced by its customers could result in the impairment of its assets, reduction of its operating cash flows and may also reduce or curtail its customers' future use of its products and services, which could reduce revenues.

Enable provides certain transportation and storage services under fixed-price "negotiated rate" contracts that are not subject to adjustment, even if the cost to perform such services exceeds the revenues received from such contracts, and, as a result, costs could exceed revenues received under such contracts.

Enable has been authorized by the FERC to provide transportation and storage services at its facilities at negotiated rates. Generally, negotiated rates are in excess of the maximum recourse rates allowed by the FERC, but it is possible that costs to perform services under "negotiated rate" contracts will exceed the revenues obtained under these agreements. If this occurs, it could decrease the cash flow realized by its systems and, therefore, decrease the cash available for distribution to its unitholders, including us.

As of December 31, 2016, approximately 54 percent of Enable's contracted firm transportation firm capacity and 44 percent of its contracted firm storage capacity was subscribed under such "negotiated rate" contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by the FERC. Successful recovery of any shortfall of revenue, representing the difference between "recourse rates" (if higher) and negotiated rates, is not assured under current FERC policies.

If third-party pipelines and other facilities interconnected to Enable's gathering, processing or transportation facilities become partially or fully unavailable to Enable for any reason, Enable's financial position, results of operations and its ability to make cash distributions to us could be adversely affected.

Enable depends upon third-party pipelines to deliver natural gas to, and take natural gas from, its natural gas transportation systems and upon third party pipelines to take crude oil from its crude oil gathering. It also depends on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of its processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of its processing plants and gathering systems, and a prolonged outage or disruption could ultimately result in a reduction in the volume of NGLs it is able to produce. Additionally, Enable depends on third parties to provide electricity for compression at many of its facilities. Since it does not own or operate any of these third-party pipelines or other facilities, continuing operation of those facilities is not within its control. If any of these third-party pipelines or other facilities become partially or fully unavailable to Enable for any reason, its financial position, results of operations and ability to make cash distributions to us could be adversely affected.

Enable does not own all of the land on which its pipelines and facilities are located, which could disrupt its operations.

Enable does not own all of the land on which its pipelines and facilities have been constructed, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights-of-way or if such rights-of-way lapse or terminate. Enable may obtain the rights to construct and operate its pipelines on land owned by third parties and governmental agencies for a specific period of time. A loss of these rights, through its inability to renew right-of-way contracts or otherwise, could cause a cease in operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable conducts a portion of its operations through joint ventures, which subjects them to additional risks that could adversely affect the success of its operations and financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable conducts a portion of its operations through joint ventures with third parties, including affiliates of Spectra Energy Partners, LP, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering, LLC. It may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside the control of Enable. If these parties do not satisfy their obligations under these arrangements, Enable's business may be adversely affected.

The joint venture arrangements of Enable may involve risks not otherwise present when operating assets directly, including, for example:

- joint venture partners may share certain approval rights over major decisions;
- joint venture partners may not pay their share of the obligations, leaving Enable liable for the liabilities created as a result of those unpaid obligations;
- possible inability to control the amount of cash it will receive from the joint venture;
- it may incur liabilities as a result of an action taken by its joint venture partners;
- it may be required to devote significant management time to the requirements of and matters relating to the joint ventures;
- its insurance policies may not fully cover loss or damage incurred by both them and its joint venture partners in certain circumstances;
- its joint venture partners may be in a position to take actions contrary to its instructions or requests or contrary to its policies or objectives; and
- disputes between them and its joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue joint ventures or to resolve disagreements with joint venture partners could adversely affect Enable's ability to transact the business that is the subject of such joint venture, which would in turn adversely affect its financial position and results of operations ability to make cash distributions to unitholders, including us. The agreements under which certain joint ventures were formed may subject them to various risks, limit the actions it may take with respect to the assets subject to the joint venture and require them to grant rights to its joint venture partners that could limit its ability to benefit fully from future positive developments. Some joint ventures require Enable to make significant capital expenditures. If it does not timely meet its financial commitments or otherwise do not comply with its joint venture agreements, its rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of its joint venture partners may have substantially greater financial resources than Enable has and it may not be able to secure the funding necessary to participate in operations its joint venture partners propose, thereby reducing its ability to benefit from the joint venture.

Under certain circumstances, affiliates of Spectra Energy Partners, LP will have the right to purchase an ownership interest in SESH at fair market value.

Enable owns a 50 percent ownership interest in SESH. The remaining 50 percent ownership interests are held by affiliates of Spectra Energy Partners, LP.

CenterPoint owns a 54.1 percent of Enable's common and subordinated units, 100.0 percent of its Series A Preferred Units and a 40 percent economic interest in Enable GP, LLC. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH Agreement), if, at any time, CenterPoint has a right to receive less than 50 percent of Enable's distributions through its interests in Enable and in the general partner, or does not have the ability to exercise certain control rights, affiliates of Spectra Energy Partners, LP could have the right to purchase Enable's interest in SESH at fair market value, subject to certain exceptions. Under the master formation agreement, Enable is entitled to receive the cash consideration related to any exercise of these rights by Spectra Energy Partners, LP or its affiliates.

An impairment of long-lived assets, including intangible assets, equity method investments or goodwill could reduce Enable's earnings.

Long-lived assets, including intangible assets with finite useful lives and property, plant and equipment, are evaluated for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment of long-lived assets is recognized if the carrying amount is not recoverable and exceeds fair value. For example, Enable recorded aggregate impairments for its Service Star business line of $38 million during the years ended December 31, 2016, 2015, 2014 and 2013, a $25 million impairment of its Atoka assets in its gathering and processing segment during the year ended December 31, 2015, and a $12 million impairment of jurisdictional pipelines in its transportation and storage segment during the year ended December 31, 2015.

Equity method investments are evaluated for impairment when events or circumstances indicate that the carrying value of the investment might not be recoverable. An impairment of an equity method investment is recognized if the fair value of the investment as a whole, and not the underlying assets, has declined and the decline is other than temporary. An example of an investment that Enable accounts for under the equity method is its investment in SESH. If Enable enters into additional joint ventures, it could have additional equity method investments.

Goodwill is evaluated for impairment on an annual basis as well as when events or circumstances change that would more likely than not reduce the fair value of a reporting unit is below its carrying amount. An impairment of goodwill is recognized if the carrying value of a reporting unit exceeds its fair value and the carrying amount of that reporting unit’s goodwill exceeds the implied value of that goodwill. For example, Enable recorded impairments to goodwill of $1.087 billion during the year ended December 31, 2015. Although as a result of these impairments Enable had no goodwill recorded as of December 31, 2016 or 2015, it could record goodwill as a result of future acquisitions.

Enable could experience future events or circumstances that result in an impairment of long-lived assets, including intangible assets, equity method investments, or goodwill. If Enable recognizes an impairment, it would take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. As a result, an impairment could have an adverse effect on Enable's results of operations and its ability to satisfy the financial ratios or other covenants under its existing or future debt agreements.

Enable's business involves many hazards and operational risks, some of which may not be fully covered by insurance. Insufficient insurance coverage and increased insurance costs could adversely affect its financial position, results of operations or ability to make cash distributions to us.

Enable's operations are subject to all of the risks and hazards inherent in the gathering, processing, transportation and storage of natural gas and crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires, earthquakes and other natural disasters, acts of terrorism and actions by third parties;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas, NGLs and crude oil as a result of the malfunction of equipment or facilities;
- ruptures, fires and explosions; and
- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury or loss of life, severe damage to and destruction of property, plant and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of its operations. A natural disaster or other hazard affecting the areas in which it operates could adversely affect Enable's results of operations. Enable is not fully insured against all risks inherent in its business. Enable currently has general liability and property insurance in place to cover certain of its facilities in amounts that it considers appropriate. Such policies are subject to certain limits and deductibles. It does not have business interruption insurance coverage for all of its operations. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of its facilities may not be sufficient to restore the loss or damage without negative impact on its results of operations and ability to make cash distributions to its unitholders, including us.

The use of derivative contracts by Enable and its subsidiaries in the normal course of business could result in financial losses that could adversely affect its financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable and its subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage its commodity and financial market risks. Enable and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts, or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact Enable's results of operations.

Enable's business is dependent on its ability to recruit, retain and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor or the unavailability of contract resources may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Enable's costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Enable's ability to manage and operate its business. If Enable is unable to successfully attract and retain an appropriately qualified workforce, its results of operations could be negatively affected.

Enable transitioned seconded employees from CenterPoint and OGE Energy to the Partnership effective January 1, 2015, except for those employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. Employees of OGE Energy that Enable determines to hire are under no obligation to accept Enable's offer of employment on the terms Enable provides, or at all.

Enable's ability to grow is dependent on its ability to access external financing sources.

Enable expects its operating subsidiaries will distribute all of their available cash to Enable and that it will distribute all of its available cash to its unitholders. As a result, Enable expects that it and its operating subsidiaries will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent Enable or its operating subsidiaries are unable to finance growth externally, its operating subsidiaries' cash distribution policy will significantly impair its operating subsidiaries' ability to grow. In addition, because it and its operating subsidiaries distribute all available cash, its operating subsidiaries' growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

To the extent Enable issues additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk it will be unable to maintain or increase its per unit distribution level, which in turn may impact the available cash that Enable has to distribute on each unit. There are no limitations in the partnership agreement on its ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by Enable or its operating subsidiaries to finance its growth strategy would result in increased interest expense, which in turn may negatively impact the available cash that its operating subsidiaries have to distribute to it, and thus that it has to distribute to its unitholders, including us.

Enable depends on access to the capital markets to fund its expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because Enable's common units are yield-based securities, rising market interest rates could impact the relative attractiveness of its common units to investors. As a result of capital market volatility, Enable may be unable to issue equity or debt on satisfactory terms, or at all, which may limit its ability to expand its operations or make future acquisitions.

Enable's merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated, which could adversely affect its financial position, results of operations or future growth.

From time to time, Enable has made, and it intends to continue to make, acquisitions of businesses and assets. Such acquisitions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;

- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;
- it may assume liabilities that were not disclosed to it, that exceed its estimates, or for which its rights to indemnification from the seller are limited;
- it may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions, or the pursuit of acquisitions, could disrupt its ongoing businesses, distract management, divert resources and make it difficult to maintain its current business standards, controls and procedures.

In addition, Enable's growth strategy includes, in part, the ability to make acquisitions on economically acceptable terms. If Enable is unable to make acquisitions or if its acquisitions do not perform as anticipated, Enable's future growth may be adversely affected.

Enable and its operating subsidiaries’ debt levels may limit its flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2016, Enable had approximately $3.0 billion of long-term debt outstanding, excluding the premiums on senior notes. Enable also has a $1.75 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.1 billion was available as of February 1, 2017. Enable will continue to have the ability to incur additional debt, subject to limitations in its credit facilities. The levels of debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms, if at all;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- the debt level will make Enable more vulnerable to competitive pressures or a downturn in the business or the economy generally; and
- the debt level may limit flexibility in responding to changing business and economic conditions.

Enable’s and its operating subsidiaries’ ability to service its debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond its control. If operating results are not sufficient to service its operating subsidiaries' current or future indebtedness, it and its subsidiaries may be forced to take actions such as reducing distributions, reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all.

Enable’s credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond its control, which could adversely affect its financial condition, results of operations and ability to make cash distributions to its unitholders, including us.

Enable's credit facilities contain customary covenants that, among other things, limit the ability to:

- permit its subsidiaries to incur or guarantee additional debt;
- incur or permit to exist certain liens on assets;
- dispose of assets;
- merge or consolidate with another company or engage in a change of control;
- enter into transactions with affiliates on non-arm’s length terms; and
- change the nature of its business.

Enable’s credit facilities also require it to maintain certain financial ratios. Its ability to meet those financial ratios can be affected by events beyond its control, and assurance it will meet those ratios cannot be guaranteed. In addition, its credit facilities contain events of default customary for agreements of this nature.

Enable's ability to comply with the covenants and restrictions contained in its credit facilities may be affected by events beyond its control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, its ability to comply with these covenants may be impaired. If any of the restrictions, covenants, ratios or tests in its credit facilities is violated, a significant portion of its indebtedness may become immediately due and payable. In addition, its lenders' commitments to make further loans to Enable under the revolving credit facility may be suspended or terminated. Enable might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Affiliates of Enable's general partner, including CenterPoint Energy and the Company, may compete with Enable, and neither the general partner nor its affiliates have any obligation to present business opportunities to Enable.

Under Enable's omnibus agreement, CenterPoint, the Company and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through Enable. This requirement will cease to apply to both CenterPoint and the Company as soon as either CenterPoint or the Company ceases to hold any interest in Enable's general partner or at least 20 percent of its common units. In addition, if CenterPoint or the Company acquires any assets or equity of any person engaged in midstream operations with a value in excess of $50.0 million (or $100.0 million in the aggregate with such party's other acquired midstream operations that have not been offered to Enable), the acquiring party will be required to offer to Enable such assets or equity for such value. If Enable does not purchase such assets, the acquiring party will be free to retain and operate such midstream assets, so long as the value of the assets does not reach certain thresholds.

As a result, under the circumstances described above, CenterPoint and the Company have the ability to construct or acquire assets that directly compete with Enable's assets. Pursuant to the terms of Enable's partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to Enable's general partner or any of its affiliates, including its executive officers and directors and CenterPoint and the Company. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for Enable will not have any duty to communicate or offer such opportunity to Enable. Any such person or entity will not be liable to Enable or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to Enable. This may create actual and potential conflicts of interest between Enable and affiliates of its general partner and result in less than favorable treatment of Enable and its common unitholders.

If Enable fails to maintain an effective system of internal controls, then it may not be able to accurately report financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in its financial reporting, which would harm Enable's business and the trading price of its common units.

Effective internal controls are necessary for Enable to provide reliable financial reports, prevent fraud and operate successfully as a public company. If its efforts to maintain internal controls are not successful, it will be unable to maintain adequate controls over its financial processes and reporting in the future and its operating results could be harmed or fail to meet its reporting obligations. Ineffective internal controls also could cause investors to lose confidence in its reported financial information, which would likely have a negative effect on the trading price of Enable's common units.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable is subject to cyber-security risks related to breaches in the systems and technology that it uses (i) to manage its operations and other business processes and (ii) to protect sensitive information maintained in the normal course of its businesses. The gathering, processing and transportation of natural gas from its gathering, processing and pipeline facilities and crude oil gathering pipeline systems are dependent on communications among its facilities and with third-party systems that may be delivering natural gas or crude oil into or receiving natural gas or crude oil and other products from its facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology, or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt its ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt its operations and critical business functions, adversely affect its reputation, and subject Enable to possible legal claims and liability. Enable is not fully insured against all cyber-security risks. In addition, its natural gas pipeline systems may be targets of terrorist activities that could disrupt its ability to conduct its business. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable may be unable to obtain or renew permits necessary for its operations, which could inhibit its ability to do business.

Performance of its operations require it obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate.

All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of Enable's compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect its ability to initiate or continue operations at the affected location or facility and on its financial condition, results of operations and ability to make cash distributions to unitholders, including us.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, Enable may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect Enable's financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable is subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife conservation, natural resources and health and safety that could, among other things, delay or increase costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. For instance, in May 2016, the EPA issued final standards governing methane emissions imposing more stringent controls on methane and volatile organic compounds emissions at new and modified oil and natural gas production, processing, storage, and transmission facilities. These rules have required changes to Enable's operations, including the installation of new equipment to control emissions. The EPA has also announced that it intends to impose methane emission standards for existing sources and has issued information collection requests to companies with production, gathering and boosting, gas processing, storage, and transmission facilities. Additionally, several states are pursuing similar measures to regulate emissions of methane from new and existing sources. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations. As a result of this continued regulatory focus, future federal and state regulations relating to Enable's gathering and processing, transmission, and storage operations remain a possibility and could result in increased compliance costs on Enable's operations. Furthermore, if new or more stringent federal, state or local legal restrictions are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which could adversely affect demand for Enable's services to those customers.

There is inherent risk of the incurrence of environmental costs and liabilities in Enable's operations due to the handling of natural gas, NGLs and crude oil and produced water as well as air emissions related to its operations and historical industry operations and waste disposal practices. These matters are subject to stringent and complex federal, state and local laws and regulations governing environmental protection, including the discharge of materials into the environment and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the handling or disposing of wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of wastes on, under or from its properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under its control. Private parties, including the owners of the properties through which its gathering systems pass and facilities where its wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non- compliance, with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of its pipelines could subject them to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Enable may be unable to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary. Further, stricter requirements could negatively impact its customers’ production and operations, resulting in less demand for its services.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by Enable's customers, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Hydraulic fracturing is a common practice that is used by many of Enable's customers to stimulate production of natural gas and crude oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in May 2016, the EPA issued final new source performance standard requirements that impose more stringent controls on methane and volatile organic compounds emissions from oil and gas development and production operations, including hydraulic fracturing and other well completion activity. The EPA also released the final results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in December 2016. The EPA concluded that hydraulic fracturing activities can impact drinking water resources under some circumstances, including large volume spills and inadequate mechanical integrity of wells. The results of EPA’s study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but not passed, legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. The EPA has issued Safe Drinking Water Act permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Additionally, the Bureau of Land Management issued final rules to regulate hydraulic fracturing on federal lands in March 2015. Although these rules were struck down by a federal court in Wyoming in June 2016, an appeal of the decision is still pending.

Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing entirely. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for Enable's services to those customers.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the OCC has implemented volume reduction plans, and at times required shut-ins, for disposal wells injecting wastewater from oil and gas operations into the Arbuckle formation. The OCC also recently released well completion seismicity guidelines for operators in the South Central Oklahoma Oil Province and the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. Enable cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs for Enable's customers, which in turn could reduce the demand for Enable's services.

Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

Enable may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because Enable's operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase its costs related to operating and maintaining its facilities, and could delay future permitting. At the federal level, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of Enable's operations. Additional rules, such as the updates to the oil and gas new source performance standard requirements finalized by the EPA in May 2016, could affect Enable's ability to obtain air permits for new or modified facilities or require its operations to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to Enable and potentially impair its operator's ability to economically develop its properties.

In addition, the U.S. Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement opened for signing on April 22, 2016 and requires countries to review and "represent a progression" in their intended nationally determined contributions, which set greenhouse gas emission reduction goals, every five years beginning in 2020. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. These programs typically require major sources of greenhouse gas emissions to acquire and surrender emission allowances in return for emitting those greenhouse gas emissions. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases could require Enable to incur costs to reduce emissions of greenhouse gases. Substantial limitations on greenhouse gas emissions could also adversely affect demand for oil and natural gas. Depending on the particular program, Enable could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could adversely affect the demand for Enable's service and its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that Enable gathers, treats and transports. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect its ability to access capital markets or cause them to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Finally, some scientists have concluded that increasing concentrations of greenhouse gases in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could adversely affect Enable's results of operations.

Enable's operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

The rates charged by several of Enable's pipeline systems, including interstate gas transportation service provided by its intrastate pipelines, are regulated by the FERC. The FERC and state regulatory agencies also regulate other terms and conditions of the services it may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower its tariff rates or deny any rate increase or other material changes to the types or terms and conditions of service it might propose or offer, the profitability of its pipeline businesses could suffer. If it were permitted to raise its tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit profitability. Furthermore, competition from other pipeline systems may prevent them from raising its tariff rates even if permitted by regulatory agencies. The regulatory agencies that regulate its systems periodically implement new rules, regulations and terms and conditions of services subject to its jurisdiction. New initiatives or orders may adversely affect the rates charged for services or otherwise adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Enable's natural gas interstate pipelines are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Generally, the FERC's authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;

- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

Should Enable fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 to impose penalties for current violations of up to $1 million per day for each violation and possible criminal penalties of up to $1 million per violation.

The FERC’s jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from the FERC. Certain minor expansions are authorized by blanket certificates that the FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that Enable will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that Enable did not anticipate. Enable's inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

The FERC conducts audits to verify compliance with the FERC’s regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. The FERC’s regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline’s FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that the FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require Enable to seek modification, or alternatively require Enable to modify its tariff so that the non-conforming provisions are generally available to all customers.

The rates, terms and conditions for transporting natural gas in interstate commerce on certain of Enable's intrastate pipelines and for services offered at certain of Enable's storage facilities are subject to the jurisdiction of the FERC under Section 311 of the Natural Gas Policy Act. Rates to provide such interstate transportation service must be "fair and equitable" under the Natural Gas Policy Act and are subject to review, refund with interest if found not to be fair and equitable, and approval by the FERC at least once every five years.

Enable's crude oil gathering pipelines are subject to common carrier regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that Enable maintain tariffs on file with the FERC setting forth the rates Enable charges for providing transportation services, as well as the rules and regulations governing such services. The Interstate Commerce Act requires, among other things, that Enable's rates must be "just and reasonable" and that Enable provide service in a manner that is nondiscriminatory. Shippers on Enable's crude oil gathering pipelines may protest its tariff filings, file complaints against its existing rates, or the FERC can investigate Enable's rates on its own initiative. In the event that the FERC finds that Enable's existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order Enable to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

Enable’s operations may also be subject to regulation by state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

The pipeline operations of Enable that are not regulated by the FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which it operates include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. The effect, if any, such changes might have on operations cannot be predicted, but Enable could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect the business. Any such state or local regulation could have an adverse effect on the business and the financial position, results of operations and ability to make cash distributions to unitholders, including us.

Gathering lines may be subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict the right by Enable as an owner of gathering facilities to decide with whom it contracts to purchase or transport oil or natural gas. Federal law leaves economic regulation of natural gas gathering to the states. The states in which it operates have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access to oil and natural gas gathering pipelines and rate discrimination.

Other state regulations may not directly regulate the business, but may nonetheless affect the availability of natural gas for processing, including state regulation of production rates and maximum daily production allowable from gas wells. While its gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the regulatory status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

A change in the jurisdictional characterization of some of Enable’s assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of its assets, which may cause its revenues to decline and operating expenses to increase.

Enable’s natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the Natural Gas Act, but the FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC’s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, it cannot be assured that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business. Although the FERC has not made a formal determination with respect to all of its facilities they consider to be gathering facilities, Enable believes that its natural gas gathering pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and is therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of its gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the Natural Gas Act and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the Natural Gas Act or the Natural Gas Policy Act. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect Enable’s financial condition, results of operations and ability to make cash distributions to its unitholders, including us. In addition, if any of its facilities were found to have provided services or otherwise operated in violation of the Natural Gas Act or Natural Gas Policy Act regulations, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by the FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enable's natural gas gathering operations could be adversely affected should it become subject to the application of state regulation of rates and services. Enable’s gathering operations could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance of gathering facilities. The effect, if any, such changes might have on its operations cannot be predicted, but additional capital expenditures could be required and increased costs could be incurred depending on future legislative and regulatory changes.

Enable may incur significant costs and liabilities resulting from compliance with pipeline safety laws and regulations, pipeline integrity and other similar programs and related repairs.

Enable's interstate pipeline operations are subject to certain pipeline safety laws and regulations administered by the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration. These laws and regulations require Enable to comply with a significant set of requirements for the design, construction, maintenance and operation of its interstate pipelines. Among other things, these laws and regulations require pipeline operators to develop integrity management programs for interstate pipelines located in “high consequence areas.” The regulations require operators, including Enable, to, among other things:

- perform ongoing assessments of pipeline integrity;
- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Failure to comply with applicable regulations could result in a number of consequences which may have an adverse effect on Enable's operations.

Changes to pipeline safety laws and regulations that result in more stringent or costly safety standards could have a significant adverse effect on Enable. For example, in August 2011, the Pipeline and Hazardous Materials Safety Administration published an advance notice of proposed rulemaking in which the agency was seeking public comment on a number of changes to regulations governing the safety of gas transmission pipelines and gathering lines, including, for example, revising the definitions of “high consequence areas” and “gathering lines” and strengthening integrity management requirements as they apply to existing regulated operators and to currently exempt operators should certain exemptions be removed. On April 8, 2016, the Pipeline and Hazardous Materials Safety Administration published a notice of proposed rulemaking responding to several of the integrity management topics raised in the August 2011 advance notice of proposed rulemaking and proposing new requirements to address safety issues for natural gas transmission and gathering lines that have arisen since the issuance of the advance notice of proposed rulemaking. The proposed rule would strengthen existing integrity management requirements, expand assessment and repair requirements to pipelines in areas with medium population densities, and extend regulatory requirements to onshore gas gathering lines that are currently exempt. Comments were due July 7, 2016. The Pipeline and Hazardous Materials Safety Administration issued, but has yet to publish, a similar rule for hazardous liquids (including oil) pipelines on January 13, 2017. This rule extends regulatory reporting requirements to all liquid gathering lines, require additional event-driven and periodic inspections, require use of leak detection systems on all hazardous liquid pipelines, modify repair criteria, and require certain pipelines to eventually accommodate inline inspection tools. It is unclear when or if this rule will go into effect as, on January 20, 2017, the Trump Administration requested that all regulations that had been sent to the Office of the Federal Register, but not yet published, be immediately withdrawn for further review. Enable is still monitoring and evaluating the effect of these requirements and proposals on its operations.

Although many of Enable's pipelines fall within a class that is currently not subject to regulation by the Pipeline and Hazardous Materials Safety Administration, it may incur significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with its nonexempt pipelines. This work is part of Enable's normal integrity management program and it does not expect to incur any extraordinary costs during 2017 to complete the testing required by existing Pipeline and Hazardous Materials Safety Administration regulations and their state counterparts. Enable has not estimated the costs for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from shutting down its pipelines during the pendency of such repairs. Should Enable fail to comply with the Pipeline and Hazardous Materials Safety Administration or comparable state regulations, it could be subject to penalties and fines. In addition, proposed rulemakings such as the notice of proposed rulemakings published on October 13, 2015 and April 8, 2016 could expand the scope of the natural gas and hazardous liquids integrity management programs and other related pipeline safety regulations to include additional requirements or previously exempt pipelines. Enable have not estimated the cost of complying with such proposed changes to the regulations administered by the Pipeline and Hazardous Materials Safety Administration.

Financial reform regulations under the Dodd-Frank Act could adversely affect Enable's ability to use derivative instruments to hedge risks associated with its business.

At times, Enable may hedge all or a portion of its commodity risk and its interest rate risk. The federal government regulates the derivatives markets and entities, including businesses like Enable, that participate in those market through the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the Commodity Futures Trading Commission and the Securities Exchange Commission to promulgate rules and regulations implementing the legislation. Under the Commodity Futures Trading Commission's regulations, Enable is subject to reporting and recordkeeping obligations for transactions involving non-financial swap transactions the Commodity Futures Trading Commissions initially adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. In December 2013, the Commodity Futures Trading Commission published a notice of proposed rulemaking designed to implement new position limits regulation and in December 2016, the Commodity Futures Trading Commission's re-proposed regulations for position limits. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The Commodity Futures Trading Commission has imposed mandatory clearing requirements on certain categories of swaps, including certain interest rate swaps, but has exempted derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as Enable has required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. Enable's management believes its hedging transactions qualify for this "commercial end-user" exception. The Dodd-Frank Act may also require Enable to comply with margin requirements in connection with its hedging activities, although the application of those provisions to Enable is uncertain at this time. The Dodd-Frank Act may also require the counterparties to its derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and related regulations could significantly increase the cost of derivatives contracts for Enable's industry (including requirements to post collateral which could adversely affect Enable's available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks Enable encounters, reduce its ability to monetize or restructure its existing derivatives contracts, and increase its exposure to less creditworthy counterparties, particularly if Enable is unable to utilize the commercial end user exception with respect to certain of its hedging transactions. If Enable reduces its use of hedging as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Enable's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could adversely affect its results of operations and its ability to make cash distributions to unitholders, including us.

Any reductions in Enable's credit ratings could increase its financing costs and the cost of maintaining certain contractual relationships.

Enable cannot provide assurance that its credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances warrant. On February 2, 2016, Standard & Poor’s Ratings Services lowered its credit rating on Enable from an investment grade rating to a non-investment grade rating. The short-term rating on Enable was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, Enable repaid its outstanding borrowings under the commercial paper program upon maturity and did not issue any additional commercial paper. If either, or both, of Moody’s Investors Service or Fitch Ratings lowers its credit ratings of Enable from an investment grade rating to a non-investment grade rating while its rating from Standard & Poor’s Ratings Services is below investment grade, the cost of Enable's borrowings will increase. So long as any of Enable's credit ratings are below investment grade, it may have higher future borrowing costs and it or its subsidiaries may be required to post cash collateral or letters of credit under certain contractual agreements. If cash collateral requirements were to occur at a time when Enable was experiencing significant working capital requirements or otherwise lacked liquidity, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Enable's Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of its common units.

Enable's 10 percent Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in Enable, issued in February 2016, rank senior to all of its other classes or series of equity securities with respect to distribution rights and rights upon liquidation. Enable cannot declare or pay a distribution to its common or subordinated unitholders for any quarter unless full distributions have been or contemporaneously are being paid on all outstanding Series A Preferred Units for such quarter. These preferences could adversely affect the cash distributions we receive from Enable, or could make it more difficult for Enable to sell its common units in the future.

Holders of the Series A Preferred Units will receive, on a non-cumulative basis and if and when declared by Enable's general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10 percent on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date, and an annual rate of the London Interbank Offered Rate plus a spread of 850 basis points on the stated liquidation preference thereafter. In connection with certain transfers of the Series A Preferred Units, the Series A Preferred Units will automatically convert into one or more new series of preferred units (the "other preferred units") on the later of the date of transfer or the second anniversary of the date of issue. The other preferred units will have the same terms as Enable's Series A Preferred Units except that unpaid distributions on the other preferred units will accrue from the date of their issuance on a cumulative basis until paid. Enable's Series A Preferred Units are convertible into common units by the holders of such units in certain circumstances. Payment of distributions on Enable's Series A Preferred Units, or on the common units issued following the conversion of such Series A Preferred Units, could impact its liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Enable's obligations to the holders of Series A Preferred Units could also limit its ability to obtain additional financing or increase its borrowing costs, which could have an adverse effect on its financial condition.

Enable's Series A Preferred Units contain covenants that may limit its business flexibility.

Enable's Series A Preferred Units contain covenants preventing it from taking certain actions without the approval of the holders of 66 2⁄3 percent of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede Enable's ability to take certain actions that management or its board of directors may consider to be in the best interests of its unitholders. The affirmative vote of 66 2⁄3 percent of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend Enable's Partnership Agreement in any manner that would or could reasonably be expected to have a material adverse effect on the rights, preferences, obligations or privileges of the Series A Preferred Units. The affirmative vote of 66 2⁄3 percent of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) create or issue certain party securities with proceeds in an aggregate amount in excess of $700.0 million or create or issue any senior securities or (B) subject to Enable's right to redeem the Series A Preferred Units, approve certain fundamental transactions.

Enable's Series A Preferred Units are required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange, and Enable may not have sufficient funds to redeem its Series A Preferred Units if it is required to do so.

The holders of Enable's Series A Preferred Units may request that Enable list those units for trading on the New York Stock Exchange. If Enable is unable to list the Series A Preferred Units in certain circumstances, it will be required to redeem the Series A Preferred Units. There can be no assurance that Enable would have sufficient financial resources available to satisfy its obligation to redeem the Series A Preferred Units. In addition, mandatory redemption of Enable's Series A Preferred Units could have a material adverse effect on its business, financial position, results of operations and ability to make quarterly cash distributions to its unitholders, including us.

Enable may issue additional units without the approval of its unitholders, which would dilute unitholders' existing ownership interests.

Enable's partnership agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, that it may issue at any time without the approval of its unitholders. The issuance by Enable of additional common units or other equity securities of equal or senior rank will have the following effects:

- Enable's existing unitholders’ proportionate ownership interest in Enable will decrease;
- the amount of distributable cash flow on each unit may decrease;

- because a lower percentage of total outstanding units will be subordinated units, the risk that a shortfall in the payment of the minimum quarterly distribution will be borne by Enable's common unitholders will increase;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

In addition, upon a change of control, Enable's Series A Preferred Units are convertible into common units at the option of the holders of such units. If a substantial portion of the Series A Preferred Units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted Series A Preferred Units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for Enable's common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for Enable to sell its common units in the future.

Affiliates of Enable's general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units.

As of February 1, 2017, subsidiaries of CenterPoint Energy and the Company held an aggregate of 136,983,998 common units and 207,855,430 subordinated units, and CenterPoint Energy holds 14,520,000 Series A Preferred Units. Upon a change of control, Enable's Series A Preferred Units are convertible into common units at the option of the holders of such units. All of the subordinated units will convert into common units at the end of the subordination period and some may convert earlier under certain circumstances. In addition, Enable has agreed to provide CenterPoint Energy, the Company and ArcLight with certain registration rights. The sale of these units in the public or private markets could have an adverse impact on the price of the common units or on any trading market that may develop.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

OG&E

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included 10 generating stations with an aggregate capability of 6,667 MWs at December 31, 2016. The following tables set forth information with respect to OG&E's electric generating facilities, all of which are located in Oklahoma.

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	2016 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	9.4%	448	
	2	1973	Steam-Turbine	Gas	14.7%	426	
	3	1975	Steam-Turbine	Gas/Oil	22.3%	471	1,345
Muskogee	4	1977	Steam-Turbine	Coal	52.4%	508	
	5	1978	Steam-Turbine	Coal	43.5%	497	
	6	1984	Steam-Turbine	Coal	39.8%	522	1,527
Sooner	1	1979	Steam-Turbine	Coal	44.8%	521	
	2	1980	Steam-Turbine	Coal	42.4%	520	1,041
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	10.5%	167	
	7	1963	Combined Cycle	Gas/Oil	8.4%	214	
	8	1969	Steam-Turbine	Gas	7.4%	405	
	9	2000	Combustion-Turbine	Gas	18.6%	46	
	10	2000	Combustion-Turbine	Gas	13.1%	46	878
Redbud (B)	1	2003	Combined Cycle	Gas	66.9%	155	
	2	2003	Combined Cycle	Gas	65.0%	154	
	3	2003	Combined Cycle	Gas	61.8%	155	
	4	2003	Combined Cycle	Gas	66.7%	152	616
Mustang	3	1955	Steam-Turbine	Gas	6.6%	120	
	4	1959	Steam-Turbine	Gas	12.6%	252	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	1.0%	28	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	1.1%	32	432
McClain (C)	1	2001	Combined Cycle	Gas	78.1%	379	379
Total Generating Capability (all stations, excluding wind stations)							6,218

Renewable

Station	Year Installed	Location	Number of Units	Fuel Capability	2016 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Crossroads	2011	Canton, OK	98	Wind	38.7%	2.3	228
Centennial	2007	Laverne, OK	80	Wind	31.9%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	36.0%	2.3	101
Total Generating Capability (wind stations)							449

(A) 2016 Capacity Factor = 2016 Net Actual Generation / (2016 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours))
(B) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(C) Represents OG&E's 77 percent ownership interest in the McClain Plant.

During 2017, OG&E anticipates retiring units 3 and 4 located at the Mustang station.

At December 31, 2016, OG&E's transmission system included: (i) 52 substations with a total capacity of 13.3 million kV-amps and 4,911 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.5 million kV-amps and 277 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 342 substations with a total capacity of 9.7 million kV-amps, 29,278 structure miles of overhead lines, 2,690 miles of underground conduit and 10,817 miles of underground conductors in Oklahoma and (ii) 30 substations with a total capacity of 0.9 million kV-amps, 2,782 structure miles of overhead lines, 270 miles of underground conduit and 692 miles of underground conductors in Arkansas.

OG&E owns 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73102. In addition to its executive offices, OG&E owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, service centers, fleet and equipment service facilities, operation support and other properties.

During the three years ended December 31, 2016, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $1.8 billion and gross retirements were $291.6 million. These additions were provided by cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to 17.0 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2016.

Item 3. Legal Proceedings.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on currently available information, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not Applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

The Company's Common Stock is listed for trading on the New York Stock Exchange under the ticker symbol "OGE." The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

		Price	
2016	Dividend Paid	High	Low
First Quarter	$ 0.2750	$ 28.74	$ 23.37
Second Quarter	0.2750	32.75	27.27
Third Quarter	0.2750	33.10	29.91
Fourth Quarter	0.3025	34.23	29.57
2015			
First Quarter	$ 0.2500	$ 36.48	$ 30.82
Second Quarter	0.2500	33.21	28.28
Third Quarter	0.2500	31.52	26.44
Fourth Quarter	0.2750	29.40	24.15

At the Company's September 2016 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.3025 per share from $0.2750 per share effective in October 2016.

The number of record holders of the Company's Common Stock at December 31, 2016, was 15,610. The book value of the Company's Common Stock at December 31, 2016 was $17.26 per share.

Dividend Restrictions

Before the Company can pay any dividends on its common stock, the holders of any of its preferred stock that may be outstanding are entitled to receive their dividends at the respective rates as may be provided for the shares of their series. Currently, there are no shares of preferred stock of the Company outstanding. Because the Company is a holding company and conducts all of its operations through its subsidiaries and equity affiliates, the Company's cash flow and ability to pay dividends is dependent on the earnings and cash flows of its subsidiaries and equity affiliate and the distribution or other payments of those earnings to the Company in the form of dividends or distributions, or in the form of repayments of loans or receipt of advances. The Company expects to derive principally all of the funds required by it to enable it to pay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock. The Company may also utilize distributions paid by Enable to help fund its capital needs and support future dividend growth. The Company's ability to receive dividends on OG&E's common stock is subject to the prior rights of the holders of any OG&E preferred stock that may be outstanding, any covenants of OG&E's certificate of incorporation and OG&E's debt instruments limiting the ability of OG&E to pay dividends and the ability of public utility commissions that regulate OG&E to effectively restrict the payment of dividends by OG&E. The Company's ability to receive distributions on its limited partnership interest in Enable is subject to Enable's cash available for distribution, the terms of its limited partnership agreement, and the covenants of Enable's debt instruments limiting the ability of Enable to pay distributions. Enable's partnership agreement requires that it distribute all "available cash," as defined as cash on hand at the end of a quarter after the payment of expenses and the establishment of cash reserves, and cash on hand resulting from working capital borrowings made after the end of the quarter.

Pursuant to the leverage restriction in the Company’s revolving credit agreement, the Company must maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $452.8 million of the Company’s retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of the Company’s retained earnings as of December 31, 2016 are unrestricted for the payment of dividends.

Pursuant to the Federal Power Act, OG&E is restricted from paying dividends from its capital accounts. Dividends are paid from retained earnings. Pursuant to the leverage restriction in OG&E’s revolving credit agreement, OG&E must also maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $351.5 million of OG&E’s retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of OG&E’s retained earnings as of December 31, 2016 are unrestricted for the payment of dividends.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

HISTORICAL DATA

Year ended December 31		**2016**		2015		2014		2013		2012
SELECTED FINANCIAL DATA										
(In millions, except per share data)										
Results of Operations Data (A):										
Operating revenues	**$**	**2,259.2**	$	2,196.9	$	2,453.1	$	2,867.7	$	3,671.2
Cost of sales		**880.1**		865.0		1,106.6		1,428.9		1,918.7
Operating expenses		**875.8**		850.7		809.7		885.3		1,075.6
Operating income		**503.3**		481.2		536.8		553.5		676.9
Equity in earnings of unconsolidated affiliates		**101.8**		15.5		172.6		101.9		—
Allowance for equity funds used during construction		**14.2**		8.3		4.2		6.6		6.2
Other income		**26.0**		27.0		17.8		31.8		17.6
Other expense		**16.9**		14.3		14.4		22.2		16.5
Interest expense		**142.1**		149.0		148.4		147.5		164.1
Income tax expense		**148.1**		97.4		172.8		130.3		135.1
Net income		**338.2**		271.3		395.8		393.8		385.0
Less: Net income attributable to noncontrolling interests		**—**		—		—		6.2		30.0
Net income attributable to OGE Energy	**$**	**338.2**	$	271.3	$	395.8	$	387.6	$	355.0
Basic earnings per average common share attributable to OGE Energy common shareholders	**$**	**1.69**	$	1.36	$	1.99	$	1.96	$	1.80
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$**	**1.69**	$	1.36	$	1.98	$	1.94	$	1.79
Dividends declared per common share	**$**	**1.15500**	$	1.05000	$	0.95000	$	0.85125	$	0.79750
Balance Sheet Data (at period end):										
Property, plant and equipment, net	**$**	**7,696.2**	$	7,322.4	$	6,979.9	$	6,672.8	$	8,344.8
Total assets (B)	**$**	**9,939.6**	$	9,580.6	$	9,509.9	$	9,120.5	$	9,909.4
Long-term debt (B)	**$**	**2,630.5**	$	2,738.8	$	2,737.4	$	2,385.9	$	2,835.8
Total stockholders' equity	**$**	**3,443.8**	$	3,326.0	$	3,244.4	$	3,037.1	$	3,072.4
Capitalization Ratios (C)										
Stockholders' equity		**56.7%**		54.7%		54.1%		55.9%		51.9%
Long-term debt		**43.3%**		45.3%		45.9%		44.1%		48.1%
Ratio of Earnings to Fixed Charges (D)										
Ratio of earnings to fixed charges		**4.41**		4.12		4.49		3.98		3.94

(A) In May 2013, Enable was formed to own and operate the midstream business of OGE Energy and CenterPoint. OGE Energy accounts for its interest in Enable using the equity method of accounting subsequent to the formation of Enable. Prior to May 1, 2013, OGE Energy consolidated the results of Enogex.

(B) The amounts for 2015, 2014, 2013 and 2012 have been adjusted for the reclassification of $16.8, $17.9, $14.2 and $12.8, respectively, of debt issuance costs from Total Deferred Charges and Other Assets to Long-Term Debt to be consistent with the 2016 presentation due to the adoption of ASU 2015-03.

(C) Capitalization ratios = [Total stockholders' equity / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year) / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)].

(D) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of income from continuing operations before income taxes and equity in earnings of unconsolidated affiliates, plus distributed equity income plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest and (ii) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and it lacks the power to direct activities that most significantly impact economic performance.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory, and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment represents the Company's investment in Enable through wholly owned subsidiaries, and ultimately OGE Holdings. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation, principally located in the Williston basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25.0 million common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2016, the Company owned 111.0 million common units, or 25.7 percent, of Enable's outstanding common units. Of the Company's 111.0 million common units, 68.2 million units were subordinated. The subordination period began on the closing date of Enable’s initial public offering and will extend until the first business day following the distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017. The Company anticipates that the subordination period will expire in August 2017 and will not impact future distributions that the Company receives from Enable.

Over the course of 2015 and continuing into early 2016, natural gas and crude oil prices dropped to their lowest levels in over 10 years. During 2016, those prices increased, but have not rebounded to the pre-2015 levels. Based on these recent commodity prices, Enable has seen changes in producer activity that have negatively impacted Enable's operations and financial position and could see additional changes in producer activity that may negatively impact Enable's operations and affect its future distribution rates. If commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted. A portion of our earnings and operating cash flows depend on the performance of, and distributions from, Enable. As disclosed in this Form 10-K, Enable is subject to a number of risks, including contract renewal risk, the reliance on the drilling and production decisions of others and the volatility of natural gas, NGL and crude oil prices. If any of those risks were to occur, the Company's business, financial condition, results of operations or cash flows could be materially adversely affected.

On February 10, 2017, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common and subordinated units, which is unchanged from the previous quarter. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. The Company is entitled to 60 percent of those "incentive distributions."

OG&E participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations, and determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

Overview

Company Strategy

The Company's mission, through OG&E and its equity interest in Enable, is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customer's needs for energy and related services, focusing on safety, efficiency, reliability, customer service and risk management. The Company's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and interest in a publicly traded midstream company, while providing competitive energy products and services to customers, as well as seeking growth opportunities in both businesses.

OG&E is focused on:

- Providing exceptional customer experiences by continuing to improve customer interfaces, tools, products and services that deliver high customer satisfaction and operating productivity.
- Providing safe, reliable energy to the communities and customers we serve. A particular focus is on enhancing the value of the grid by improving distribution grid reliability by reducing the frequency and duration of customer interruptions and leveraging previous grid technology investments.
- Having strong regulatory and legislative relationships for the long-term benefit of our customers, investors and members.
- Continuing to grow a zero-injury culture and deliver top-quartile safety results.
- Complying with the EPA's MATS and Regional Haze Rule requirements.
- Ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers.
- Continuing focus on operational excellence and efficiencies in order to protect the customer bill.

Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders. The Company's financial objectives include a long-term annual earnings growth rate for OG&E of three to five percent on a weather-normalized basis, maintaining a strong credit rating as well as targeting dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets and the composition of the Company's assets and investment opportunities. The Company also utilizes cash distributions from its investment in Enable to help fund its capital needs and support future dividend growth. The Company believes it can accomplish these financial objectives by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and having strong regulatory and legislative relationships.

Summary of Operating Results

2016 compared to 2015. Net income was $338.2 million, or $1.69 per diluted share, in 2016 as compared to $271.3 million, or $1.36 per diluted share, in 2015. The increase in net income of $66.9 million, or 24.7 percent, or $0.33 per diluted share, in 2016 as compared to 2015 was primarily due to:

- an increase in net income at OGE Holdings of $44.3 million, or $0.22 per diluted share of the Company's common stock, primarily due to the goodwill impairment adjustment at Enable in September 2015 partially offset by higher income tax expense due to higher pre-tax operating income and a change in state tax rates;
- an increase in net income at OG&E of $15.2 million, or 5.7 percent**,** or $0.07 per diluted share of the Company's common stock, primarily due to an increase in gross margin related to warmer summer weather and increased wholesale transmission revenues and an increase in other income. Partially offsetting these items was an increase in other operation and maintenance expense, an increase in depreciation expense due to additional assets being placed in service and an increase in income tax expense; and

- an increase in net income at OGE Energy of $7.4 million, or $0.04 per diluted share of the Company's common stock, primarily due to charges in 2015 associated with pre-construction expenditures for cancelled new office space to consolidate Oklahoma City personnel and a decrease in depreciation partially offset by an increase in interest expense.

2015 compared to 2014. Net income was $271.3 million, or $1.36 per diluted share, in 2015 as compared to $395.8 million, or $1.98 per diluted share, in 2014. The decrease in net income of $124.5 million, or 31.5 percent, or $0.62 per diluted share, in 2015 as compared to 2014 was primarily due to:

- a decrease in net income at OGE Holdings of $92.9 million, or 90.8 percent, or $0.46 per diluted share of the Company's common stock, primarily due to the goodwill impairment adjustment at Enable in September 2015 and lower revenues driven by lower average natural gas and NGLs prices;
- a decrease in net income at OG&E of $23.1 million, or 7.9 percent, or $0.11 per diluted share of the Company's common stock, primarily due to an increase in depreciation expense due to additional assets being placed in service in 2015, and a decrease in gross margin related to milder weather and decreased wholesale transmission revenues. Partially offsetting these items was an increase in customer growth, an increase in other income and an increase in allowance for equity funds used during construction; and
- a decrease in net income at OGE Energy of $8.5 million, or $0.05 per diluted share of the Company's common stock, primarily due to charges associated with pre-construction expenditures for new office space to consolidate Oklahoma City personnel.

A more detailed discussion regarding the financial performance of OG&E and the Natural Gas Midstream Operations can be found under "Results of Operations" below.

2017 Outlook

Key assumptions for 2017 include:

OG&E

The Company projects OG&E to earn approximately $316 million to $340 million or $1.58 to $1.70 per average diluted share in 2017 and is based on the following assumptions:

- normal weather patterns are experienced for the remainder of the year;
- new rates take effect in Oklahoma and Arkansas in 2017;
- gross margin on revenues of approximately $1.470 billion to $1.485 billion based on sales growth of approximately one percent on a weather-adjusted basis;
- approximately $110 million of gross margin is primarily attributed to regionally allocated transmission projects;
- operating expenses of approximately $896 million to $917 million, with operation and maintenance expenses comprising 54 percent of the total;
- interest expense of approximately $147 million which assumes a $15 million allowance for borrowed funds used during construction reduction to interest expense and assumes a debt issuance of $300 million in the first half of 2017;
- other income of approximately $60 million including approximately $34 million of allowance for equity funds used during construction;
- recovery of $8 million of expiring production tax credits or $0.04 per average diluted share;
- an effective tax rate of approximately 32 percent;
- assumes revenue of approximately $23 million or net income of approximately $14 million or $0.07 per average diluted share for rates implemented on July 1, 2016 through December 31, 2016 based on the findings in the ALJ's report associated with the Oklahoma General Rate Case and based on 9.87 percent return on equity; and
- every 10 basis point change in the allowed Oklahoma return on equity equates to a change of approximately $3.6 million in revenue.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

OGE Enogex Holdings LLC

The Company projects the earnings contribution from its ownership interest in Enable Midstream to be approximately $70 million to $78 million or $0.35 to $0.39 per average diluted share and receive approximately $140 million in cash distributions.

Consolidated OGE

The Company’s 2017 earnings guidance is between approximately $386 million and $418 million of net income, or $1.93 to $2.09 per average diluted share and is based on the following assumptions:

- approximately 200 million average diluted shares outstanding; and
- an effective tax rate of approximately 33 percent.

OG&E's Non-GAAP Financial Measures

Gross margin is defined by OG&E as operating revenues less fuel, purchased power and certain transmission expenses. Gross margin is a non-GAAP financial measure because it excludes depreciation and amortization, and other operation and maintenance expenses. Expenses for fuel and purchased power are recovered through fuel adjustment clauses and as a result changes in these expenses are offset in operating revenues with no impact on net income. OG&E believes gross margin provides a more meaningful basis for evaluating its operations across periods than operating revenues because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Board of Directors. OG&E's definition of gross margin may be different from similar terms used by other companies. For a reconciliation of gross margin to revenue for the years ended December 31, 2016, 2015 and 2014, see OG&E (Electric Utility) Results of Operations below.

Detailed below is a reconciliation of gross margin to revenue included in the 2017 Outlook.

Reconciliation of Gross Margin to Revenue

Year Ended December 31, (Dollars in Millions)		2017 (A)
Operating revenues	$	2,088
Cost of sales		610
Gross margin	$	1,478

(A) Based on the midpoint of OG&E earnings guidance for 2017.

Enable's Non-GAAP Financial Measures

Gross margin is defined by Enable as total revenues minus costs of natural gas and NGLs, excluding depreciation and amortization. Total revenues consist of the fees that they charge their customers and the sales price of natural gas and NGLs that they sell. The cost of natural gas and NGLs consists of the purchase price of natural gas and NGLs that they purchase. Enable deducts the cost of natural gas and NGLs from total revenue to arrive at a measure of the core profitability of their mix of fee-based and commodity-based customer arrangements. Gross margin allows for meaningful comparison of the operating results between Enable's fee-based revenues and Enable's commodity-based contracts which involve the purchase or sale of natural gas, NGLs and/or crude oil. In addition, the Company believes gross margin allows for a meaningful comparison of the results of Enable's commodity-based activities across different commodity price environments because it measures the spread between the product sales price and cost of products sold.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the years ended December 31, 2016, 2015 and 2014 and the Company's consolidated financial position at December 31, 2016 and 2015. The following information should be read in conjunction with the Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Year Ended December 31,		
(In millions except per share data)	**2016**	2015	2014
Net income	**$ 338.2**	$ 271.3	$ 395.8
Basic average common shares outstanding	**199.7**	199.6	199.2
Diluted average common shares outstanding	**199.9**	199.6	199.9
Basic earnings per average common share	**$ 1.69**	$ 1.36	$ 1.99
Diluted earnings per average common share	**$ 1.69**	$ 1.36	$ 1.98
Dividends declared per common share	**$ 1.15500**	$ 1.05000	$ 0.95000

Results by Business Segment

	Year Ended December 31,		
(In millions)	**2016**	2015	2014
Net income (loss)			
OG&E (Electric Utility)	**$ 284.1**	$ 268.9	$ 292.0
OGE Holdings (Natural Gas Midstream Operations) (A)	**53.7**	9.4	102.3
Other Operations (B)	**0.4**	(7.0)	1.5
Consolidated net income	**$ 338.2**	$ 271.3	$ 395.8

(A) The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis differences. See Note 3 for further discussion of Enable's goodwill impairment.

(B) Other Operations primarily includes the operations of the holding company and consolidating eliminations.

The following operating results analysis by business segment includes intercompany transactions that are eliminated in the Consolidated Financial Statements.

OG&E (Electric Utility)

Year ended December 31 *(Dollars in millions)*	**2016**	2015	2014
Operating revenues	**$ 2,259.2**	$ 2,196.9	$ 2,453.1
Cost of sales	**880.1**	865.0	1,106.6
Other operation and maintenance	**469.8**	444.5	453.2
Depreciation and amortization	**316.4**	299.9	270.8
Taxes other than income	**84.0**	87.1	84.5
Operating income	**508.9**	500.4	538.0
Allowance for equity funds used during construction	**14.2**	8.3	4.2
Other income	**16.4**	13.3	4.8
Other expense	**2.9**	1.6	1.9
Interest expense	**138.1**	146.7	141.5
Income tax expense	**114.4**	104.8	111.6
Net income	**$ 284.1**	$ 268.9	$ 292.0
Operating revenues by classification			
Residential	**$ 951.9**	$ 896.5	$ 925.5
Commercial	**573.7**	535.0	583.3
Industrial	**194.6**	190.6	224.5
Oilfield	**156.9**	162.8	188.3
Public authorities and street light	**204.3**	194.2	220.3
Sales for resale	**0.3**	21.7	52.9
System sales revenues	**2,081.7**	2,000.8	2,194.8
Provision for rate refund	**(33.6)**	—	—
Integrated market	**49.3**	48.6	94.1
Other	**161.8**	147.5	164.2
Total operating revenues	**$ 2,259.2**	$ 2,196.9	$ 2,453.1
Reconciliation of gross margin to revenue:			
Operating revenues	**$ 2,259.2**	$ 2,196.9	$ 2,453.1
Cost of sales	**880.1**	865.0	1,106.6
Gross margin	**$ 1,379.1**	$ 1,331.9	$ 1,346.5
MWh sales by classification *(In millions)*			
Residential	**9.3**	9.2	9.4
Commercial	**7.6**	7.4	7.2
Industrial	**3.6**	3.6	3.8
Oilfield	**3.2**	3.4	3.4
Public authorities and street light	**3.2**	3.1	3.2
Sales for resale	**—**	0.5	1.0
System sales	**26.9**	27.2	28.0
Integrated market	**3.0**	1.7	2.2
Total sales	**29.9**	28.9	30.2
Number of customers	**833,582**	824,776	814,982
Weighted-average cost of energy per kilowatt-hour - cents			
Natural gas	**2.488**	2.529	4.506
Coal	**2.213**	2.187	2.152
Total fuel	**2.199**	2.196	2.752
Total fuel and purchased power	**2.842**	2.874	3.493
Degree days (A)			
Heating - Actual	**2,800**	3,038	3,569
Heating - Normal	**3,349**	3,349	3,349
Cooling - Actual	**2,247**	2,071	2,114
Cooling - Normal	**2,092**	2,092	2,092

(A) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

2016 compared to 2015. OG&E's net income increased $15.2 million, or 5.7 percent, in 2016 as compared to 2015 primarily due to an increase in gross margin related to warmer summer weather and increased transmission revenues and an increase in other income partially offset by increases in other operation and maintenance expense, depreciation expense and income tax expense.

Operating revenues were $2,259.2 million in 2016 as compared to $2,196.9 million in 2015, an increase of $62.3 million, or 2.8 percent. Cost of sales were $880.1 million in 2016 as compared to $865.0 million in 2015, an increase of $15.1 million, or 1.7 percent. Gross margin was $1,379.1 million in 2016 as compared to $1,331.9 million in 2015, an increase of $47.2 million, or 3.5 percent. The below factors contributed to the change in gross margin:

(In millions)	$ Change
Interim rate increase - Oklahoma (A)	$ 39.0
Reserve for rate refund (A)	(33.7)
Wholesale transmission revenue (B)	20.3
Price variance (C)	18.1
Quantity variance (primarily weather)	13.1
New customer growth	3.2
Non-residential demand and related revenues	0.6
Other	(3.7)
Expiration of AVEC contract (D)	(9.7)
Change in gross margin	$ 47.2

(A) As discussed in Note 14, on July 1, 2016, OG&E implemented an annual interim rate increase of $69.5 million. Interim rates are subject to refund of any amount recovered in excess of the rates ultimately approved by the OCC in the general rate case.

(B) Increased primarily due to the SPP's settlement of revenue credits related to the Windspeed Transmission line for the years 2008 through August 2016. Other increases include a recovery of the base plan projects in the SPP formula rate for 2015 and 2016.

(C) Increased primarily due to the reversal of a reserve for gas transportation charges in addition to the pricing impact of weather related sales.

(D) On June 30, 2015, the wholesale power contract with AVEC expired.

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $470.7 million in 2016 as compared to $458.5 million in 2015, an increase of $12.2 million, or 2.7 percent, primarily due to higher volumes of natural gas used partially offset by lower natural gas prices. In 2016, OG&E's fuel mix was 48.0 percent coal, 45.3 percent natural gas and 6.7 percent wind. In 2015, OG&E's fuel mix was 49.0 percent coal, 44.0 percent natural gas and seven percent wind. Purchased power costs were $350.3 million in 2016 as compared to $362.6 million in 2015, a decrease of $12.3 million, or 3.4 percent, primarily due to a decrease in purchases from the SPP. Transmission related charges were $59.1 million in 2016 as compared to $43.9 million in 2015, an increase of $15.2 million, or 34.6 percent, primarily due to higher SPP charges for the base plan projects of other utilities and SPP charges for the Windspeed Transmission line for the years 2008 through August 2016.

The actual cost of fuel used in electric generation and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC and the APSC. The OCC and the APSC have the authority to review the appropriateness of gas transportation charges or other fees OG&E pays to its affiliate, Enable.

Operating Expenses

Other operation and maintenance expense was $469.8 million in 2016 as compared to $444.5 million in 2015, an increase of $25.3 million, or 5.7 percent. The below factors contributed to the change in other operation and maintenance expense:

(In millions)		$ Change
Salaries and wages (A)	$	10.4
Contract professional services (B)		8.7
Corporate allocations and overheads (C)		8.1
Other		(1.9)
Change in other operation and maintenance expense	$	25.3

(A) Increased primarily due to increases in incentive compensation, pension expense, annual salaries and medical/dental expense partially offset by a decrease in overtime.

(B) Increased primarily due to increased consulting costs associated with demand side management programs.

(C) Increased primarily due to additional direct support in information technology, facility direct support, strategy and marketing support.

Depreciation and amortization expense was $316.4 million in 2016 as compared to $299.9 million in 2015, an increase of $16.5 million, or 5.5 percent, primarily due to additional assets being placed in service and amortization of deferred storm costs.

Taxes other than income taxes was $84.0 million in 2016 as compared to $87.1 million in 2015, a decrease of $3.1 million, or 3.6 percent, due to increased capitalization of ad valorem taxes primarily associated with environmental projects.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $14.2 million in 2016 as compared to $8.3 million in 2015, an increase of $5.9 million, or 71.1 percent, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Other Income. Other income was $16.4 million in 2016 as compared to $13.3 million in 2015, an increase of $3.1 million, or 23.3 percent, primarily due to an increase in the tax gross up related to higher allowance for equity funds used during construction and an increase in interest income related to riders partially offset by decreased guaranteed flat bill margins.

Other Expense. Other expense was $2.9 million in 2016 as compared to $1.6 million in 2015, an increase of $1.3 million, or 81.3 percent, primarily due to increased other miscellaneous expenses, increased charitable donations during 2016 and an increase in consulting services.

Interest Expense. Interest expense was $138.1 million in 2016 compared to $146.7 million in 2015, a decrease of $8.6 million, or 5.9 percent, primarily due to the retirement of senior notes in January 2016, partially offset by increased allowance for borrowed funds used during construction, primarily associated with environmental projects.

Income Tax Expense. Income tax expense was $114.4 million in 2016 as compared to $104.8 million in 2015, an increase of $9.6 million, or 9.2 percent, primarily due to higher pre-tax operating income in addition to lower renewable energy credits.

2015 compared to 2014. OG&E's net income decreased $23.1 million, or 7.9 percent, in 2015 as compared to 2014 primarily due to higher depreciation expense and lower gross margin partially offset by higher other income and an increase in allowance for equity funds used in construction.

Operating revenues were $2,196.9 million in 2015 as compared to $2,453.1 million in 2014, a decrease of $256.2 million, or 10.4 percent. Cost of sales were $865.0 million in 2015 as compared to $1,106.6 million in 2014, a decrease of $241.6 million, or 21.8 percent. Gross margin was $1,331.9 million in 2015 as compared to $1,346.5 million in 2014, a decrease of $14.6 million, or 1.1 percent. The below factors contributed to the change in gross margin:

(In millions)		$ Change
Quantity variance (primarily weather) (A)	$	(25.8)
Wholesale transmission revenue (B)		(19.8)
Expiration of AVEC contract (C)		(11.5)
Industrial and oilfield sales		(4.5)
Other		2.1
Non-residential demand and related revenues		3.7
Price Variance (D)		19.8
New customer growth		21.4
Change in gross margin	$	(14.6)

(A) The overall cooling degree days decreased two percent in 2015 compared to 2014 with August decreasing by 14.0 percent.
(B) Decreased primarily due to a true up for the base plan projects in the SPP formula rate for 2014 and 2015 as well as a reduction in the point-to-point credits shared with retail customers.
(C) On June 30, 2015, the wholesale power contract with AVEC expired.
(D) Increased primarily due to sales and customer mix.

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $458.5 million in 2015 as compared to $627.5 million in 2014, a decrease of $169.0 million, or 26.9 percent, primarily due to lower natural gas prices offset by higher natural gas used. In 2015, OG&E's fuel mix was 49.0 percent coal, 44.0 percent natural gas and seven percent wind. In 2014, OG&E's fuel mix was 61.0 percent coal, 32.0 percent natural gas and seven percent wind. Purchased power costs were $362.6 million in 2015 as compared to $444.1 million in 2014, a decrease of $81.5 million, or 18.4 percent, primarily due to a decrease in purchases from the SPP, reflecting the impact of OG&E's participation in the SPP Integrated Marketplace, which began on March 1, 2014. Transmission related charges were $43.9 million in 2015 as compared to $35.0 million in 2014, an increase of $8.9 million, or 25.4 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

The actual cost of fuel used in electric generation and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to its affiliate, Enable.

Operating Expenses

Other operation and maintenance expense was $444.5 million in 2015 as compared to $453.2 million in 2014, a decrease of $8.7 million, or 1.9 percent. The below factors contributed to the change in other operation and maintenance expense:

(In millions)		$ Change
Additional capitalized labor (A)	$	(9.2)
Maintenance at power plants (B)		(7.0)
Professional service contracts (C)		(2.1)
Other		(1.0)
Employee benefits (D)		1.0
Other marketing, sales and commercial (E)		2.8
Salaries and wages (F)		6.8
Change in other operation and maintenance expense	$	(8.7)

(A) Decreased primarily due to more capital projects and storm costs exceeding the $2.7 million threshold, which were moved to a regulatory asset.
(B) Decreased primarily due to less work at the power plants.
(C) Decreased primarily due to decreased engineering services.
(D) Increased primarily due to higher medical costs incurred partially offset by lower pension costs.
(E) Increased primarily due to higher demand side management customer payments.
(F) Increased primarily due to annual salary increases and increased overtime related to storms.

Depreciation and amortization expense was $299.9 million in 2015 as compared to $270.8 million in 2014, an increase of $29.1 million, or 10.7 percent, primarily due to additional assets being placed in service, along with an increase resulting from the amortization of deferred pension credits and post-retirement medical regulatory liabilities which were fully amortized in July 2014 and amortization of deferred storm costs.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $8.3 million in 2015 as compared to $4.2 million in 2014, an increase of $4.1 million or 97.6 percent, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Other Income. Other income was $13.3 million in 2015 as compared to $4.8 million in 2014, an increase of $8.5 million, primarily due to increased guaranteed flat bill margins and an increase in the tax gross up related to higher allowance for funds used during construction.

Income Tax Expense. Income tax expense was $104.8 million in 2015 as compared to $111.6 million in 2014, a decrease of $6.8 million, or 6.1 percent, primarily due to lower pretax income partially offset by a reduction in Federal tax credits.

OGE Holdings (Natural Gas Midstream Operations)

	Year Ended December 31,		
(In millions)	**2016**	2015	2014
Operating revenues	**$ —**	$ —	$ —
Cost of sales	**—**	—	—
Other operation and maintenance	**7.7**	7.5	1.2
Depreciation and amortization	**—**	—	—
Taxes other than income	**—**	—	—
Operating income (loss)	**(7.7)**	(7.5)	(1.2)
Equity in earnings of unconsolidated affiliates (A)	**101.8**	15.5	172.6
Other income	**0.1**	0.4	—
Income before taxes	**94.2**	**8.4**	**171.4**
Income tax expense (benefit)	**40.5**	(1.0)	69.1
Net income attributable to OGE Holdings	**$ 53.7**	**$ 9.4**	**$ 102.3**

(A) The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis difference. See Note 3 for further discussion of Enable's goodwill impairment.

Equity in earnings of unconsolidated affiliates includes the Company's share of Enable earnings adjusted for the amortization of the basis difference of the Company's investment in Enogex and its underlying equity in the net assets of Enable and is also adjusted for the elimination of the Enogex Holdings fair value adjustments.

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $743.7 million as of December 31, 2016. The basis difference is being amortized over approximately 30 years, beginning in May 2013. The following table reconciles the basis difference in Enable from December 31, 2015 to December 31, 2016.

(In millions)	
Basis difference as of December 31, 2015	$ 783.5
Dilution and impairments associated with OGE Energy’s basis difference	(11.3)
Amortization of basis difference	(11.6)
Elimination of Enable fair value step up	(16.9)
Basis difference as of December 31, 2016	$ 743.7

Reconciliation of Equity in Earnings of Unconsolidated Affiliates

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2016 and 2015.

	Year Ended December 31,	
(In millions)	**2016**	2015
Enable net income (loss)	**$ 289.5**	$ (752.0)
Distributions senior to limited partners	**(9.1)**	—
Differences due to timing of OGE Energy and Enable accounting close	**(12.1)**	12.1
Enable net income (loss) used to calculate OGE Energy's equity in earnings	**$ 268.3**	**$ (739.9)**
OGE Energy’s percent ownership at year end	**25.7%**	26.3%
OGE Energy’s portion of Enable net income (loss)	**$ 70.7**	$ (194.4)
Impairments recognized by Enable associated with OGE Energy’s basis differences	**2.6**	178.4
OGE Energy's share of Enable net income (loss)	**73.3**	**(16.0)**
Amortization of basis difference	**11.6**	13.5
Elimination of Enable fair value step up	**16.9**	18.0
Equity in earnings of unconsolidated affiliates	**$ 101.8**	**$ 15.5**

Enable Results of Operations

The following tables represents summarized financial information of Enable for 2016, 2015 and 2014:

	Year Ended December 31,		
(In millions)	**2016**	2015	2014
Operating revenues	**$ 2,272**	$ 2,418	$ 3,367
Cost of natural gas and natural gas liquids	**1,017**	1,097	1,914
Operating income (loss)	**385**	(712)	586
Net income (loss)	**$ 290**	$ (752)	$ 530

	Year Ended December 31,		
	2016	2015	2014
Gathered volumes - TBtu/d	**3.13**	3.14	3.34
Transportation volumes - TBtu/d	**4.88**	4.97	4.95
Natural gas processed volumes - TBtu/d	**1.80**	1.78	1.56
NGLs sold - million gallons/d (A)(B)	**78.16**	75.55	68.67

Year Ended December 31, 2016 as Compared to Year Ended December 31, 2015

OGE Holdings' earnings before taxes increased $85.8 million for the year ended December 31, 2016 as compared to the same period of 2015 primarily due to an increase in equity in earnings of Enable of $86.3 million. This increase in the Company's equity in earnings of Enable was attributable primarily to an increase in Enable's operating income, which increased $1.097 billion during the year ended December 31, 2016 as compared to 2015. This increase was primarily due to goodwill and asset impairments recorded by Enable in 2015 of $1.125 billion. In addition to the $108.4 million goodwill impairment that the Company recognized during 2015, other factors that contributed to the increase in Enable's operating income and their impact on the Company's equity in earnings of Enable included a decrease in operation and maintenance expense that includes administrative expense of $56.0 million that increased the Company's equity in earnings of Enable by approximately $15.0 million and was partially offset by a decrease in Enable's gross margin of $66.0 million that decreased the Company's equity in earnings of Enable by $17.0 million.

Enable's gathering and processing business segment reported an increase in operating income of $499 million. Goodwill and asset impairments recorded in 2015 positively impacted operating income by $534 million in 2016. Absent the impact of such impairment, operating income decreased $35 million due primarily to a reduction in gross margin of $33 million that decreased the Company's equity in earnings of Enable by $9 million and an increase in depreciation and amortization expense of $17 million that decreased the Company's equity in earnings of Enable by approximately $4 million. Partially offsetting the impact of decreased gross margin and increased depreciation and amortization, there was a decrease of $17 million in operation and maintenance expenses that increased the Company's equity in earnings of Enable by $4 million. Gathering and processing gross margin decreased primarily due to lower commodity prices and a decrease due to one-time project reimbursements partially offset by increased volumes in the Williston basin, increased billings under minimum volume commitments, higher rates on fee-based gathering services and an increase in the imbalance receivable associated with the annual fuel rate determination.

Enable's transportation and storage segment reported an increase in operating income of $601 million. Goodwill and asset impairments recorded in 2015 represented $591 million of this increase. In addition, a decrease of $39 million in operation and maintenance expense increased the Company's equity in earnings of Enable by $10 million. Partially offsetting these increases was a decrease in gross margin of $29 million that decreased the Company's equity in earnings of Enable by $8 million, primarily due to lower margin on unrealized natural gas derivatives, lower system management activities and lower firm transportation revenues partially offset by an increase in gross margin from transportation services for local distribution companies.

Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years. Should lower commodity prices persist, or should commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted.

Income Tax Expense. Income tax expense was $40.5 million in 2016 as compared to a benefit of $1.0 million in 2015, an increase in expense of $41.5 million primarily due to higher pre-tax operating income and a state deferred tax revaluation resulting from a change in state tax rates.

Year Ended December 31, 2015 as Compared to Year Ended December 31, 2014

OGE Holdings' earnings before taxes decreased $163.0 million, or 95.1 percent, for the year ended December 31, 2015 as compared to the same period of 2014 primarily due to a decrease in equity in earnings of Enable of $157.1 million. This decrease in the Company’s equity in earnings of Enable was attributable primarily to a reduction in Enable’s operating income, which decreased $1.298 billion during the year ended December 31, 2015 as compared to the same period of 2014. Goodwill and asset impairments represented $1.126 billion of such $1.298 billion decrease. In addition to the $108.4 million goodwill impairment that the Company recognized during 2015, other factors that contributed to the decrease in Enable’s operating income and their impact on the Company’s equity in earnings of Enable included (i) a decrease in Enable’s gross margin of $132 million that decreased the Company’s equity in earnings of Enable by approximately $35 million, (ii) an increase in depreciation and amortization expense of $42 million that decreased the Company’s equity in earnings of Enable by approximately $11 million and (iii) an increase in taxes other than income taxes of $3 million that decreased the Company’s equity in earnings of Enable by approximately $1 million.

Enable's gathering and processing business segment reported a decrease in operating income of $655 million, of which $535 million related to goodwill and asset impairments. The balance of this decrease, $120 million, was primarily from (i) a decrease in gross margin of $84 million that decreased the Company’s equity in earnings of Enable by approximately $22 million, (ii) an increase in depreciation and amortization expense of $35 million that decreased the Company’s equity in earnings of Enable by approximately $9 million, and (iii) an increase in taxes other than income taxes of $5 million that decreased the Company’s equity in earnings of Enable by approximately $1 million. Gathering and processing gross margin decreased primarily due to lower commodity prices partially offset by increased volumes in the Anadarko and Williston basins.

Enable’s transportation and storage segment reported a decrease in operating income of $643 million of which $591 million related to goodwill and asset impairments. The balance of this decrease $52 million, was primarily from (i) a decrease in gross margin of $49 million that decreased the Company’s equity in earnings of Enable by approximately $13 million, primarily due to lower margin on unrealized natural gas derivatives, a decrease in sales of NGLs due to lower prices, lower firm transportation revenues, a decrease in storage demand fees as well as lower rates on transportation services for local distribution companies and (ii) increased depreciation expenses of $7 million that decreased the Company’s equity in earnings of Enable by approximately $2 million. These decreases were partially offset by higher margin related to realized gains on system optimization activities and increased margin from higher rates on off-system transportation services.

Income Tax Expense. Income tax benefit was $1.0 million in 2015 as compared to an expense of $69.1 million in 2014, a decrease in expense of $70.1 million primarily due to lower pre-tax operating income, a benefit recognized associated with a remeasurement of deferred taxes related to the Company's investment in Enable and the impact of the goodwill impairment on Enable.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with a purchase option, covering approximately 1,250 rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to fuel expense and are recovered through OG&E's tariffs and fuel adjustment clauses.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed.

On October 14, 2014, OG&E signed a separate three-year lease effective December 2014 for 131 railcars to replace railcars that have been taken out of service or destroyed.

On December 17, 2015, OG&E renewed the lease agreement effective February 1, 2016. At the end of the new lease term, which is February 1, 2019, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $18.3 million. OG&E is also required to maintain all of the railcars it has under the operating lease.

Liquidity and Capital Resources

Working Capital

Working capital is defined as the difference in current assets and current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

Cash and Cash Equivalents. There was a balance of $0.3 million in Cash and Cash Equivalents at December 31, 2016 compared to a balance of $75.2 million at December 31, 2015, a decrease of $74.9 million, primarily due to the use of cash and payment of long-term debt of $110.0 million that matured in January 2016.

Accounts Receivable and Accrued Unbilled Revenues. The balance of Accounts Receivable and Accrued Unbilled Revenues was $235.2 million and $228.3 million at December 31, 2016 and 2015, respectively, an increase of $6.9 million, or 3.0 percent, primarily due to an increase in billings to OG&E's retail customers reflecting higher usage in December 2016 compared to December 2015.

Fuel Inventories. The balance of Fuel Inventories was $79.8 million and $113.8 million at December 31, 2016 and 2015, respectively, a decrease of $34.0 million, or 29.9 percent, primarily due to lower coal inventory balances resulting from increased production from coal plants in 2016 and lower average prices.

Fuel Clause Recoveries. The Fuel Clause balance was an under recovery of $51.3 million at December 31, 2016 compared to an over recovery of $61.3 million at December 31, 2015, primarily due to lower amounts billed to OG&E retail customers as compared to the actual cost of fuel and purchased power.

Other Current Assets. The balance of Other Current Assets was $81.8 million and $55.6 million at December 31, 2016 and 2015, respectively, an increase of $26.2 million, or 47.1 percent, primarily due to lower revenue collections from customers associated with various rate riders.

Short-Term Debt. The balance of Short-term Debt was $236.2 million at December 31, 2016 compared to no balance at December 31, 2015. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements.

Accounts Payable. The balance of Accounts Payable was $205.4 million and $262.5 million at December 31, 2016 and 2015, respectively, a decrease of $57.1 million, or 21.8 percent, primarily due to a decrease in accruals and the timing of vendor payments partially offset by an increase in fuel and purchased power expense.

Accrued Taxes. The balance of Accrued Taxes was $41.3 million and $45.9 million at December 31, 2016 and 2015, respectively, a decrease of $4.6 million, or 10.0 percent, due to tax payments of $82.8 million partially offset by accruals of $77.1 million and an increase of $1.1 million due to net state income tax accruals.

Accrued Compensation. The balance of Accrued Compensation was $45.1 million and $54.4 million at December 31, 2016 and 2015, respectively, a decrease of $9.3 million, or 17.1 percent, primarily resulting from the payout of 2015 retirement benefits that were paid, labor accrued but not paid and forfeited vacation partially offset by an increase in accrued incentive compensation.

Long-Term Debt Due Within One Year. The balance of Long-Term Debt Due Within One Year was $224.7 million and $110.0 million at December 31, 2016 and 2015, respectively, an increase of $114.7 million, primarily due to long-term debt that matured in January 2016 and the reclassification of long-term debt that will mature July 2017 and the reclassification of long-term debt that will mature in November 2017.

Other Current Liabilities. The balance of Other Current Liabilities was $96.0 million and $43.9 million at December 31, 2016 and 2015, respectively, an increase of $52.1 million, primarily due to revenue that has been collected from customers but is reserved and subject to refund until the Company receives a rate case order from the OCC and the SPP credits that will be returned to customers.

Cash Flows

				2016 vs. 2015		2015 vs. 2014	
Year ended December 31 *(In millions)*	**2016**	2015	2014	**$ Change**	**% Change**	$ Change	% Change
Net cash provided from operating activities	**$ 644.6**	$ 865.4	$ 721.6	**$ (220.8)**	**(25.5)%**	$ 143.8	19.9 %
Net cash used in investing activities	**(620.4)**	(500.1)	(559.1)	**(120.3)**	**24.1 %**	59.0	(10.6)%
Net cash used in financing activities	**(99.1)**	(295.6)	(163.8)	**196.5**	**(66.5)%**	(131.8)	80.5 %

Operating Activities

The decrease of $220.8 million, or 25.5 percent, in net cash provided from operating activities in 2016 as compared to 2015 was primarily due to a return of cash from fuel over recoveries to customers at OG&E.

The increase of $143.8 million, or 19.9 percent, in net cash provided from operating activities in 2015 as compared to 2014 was primarily due to an increase in cash received from fuel recoveries at OG&E and less cash paid to vendors, partially offset by Enable distributions classified as a return of capital in investing activities.

Investing Activities

The increase of $120.3 million, or 24.1 percent, in net cash used in investing activities in 2016 as compared to 2015 was primarily due to an increase in capital expenditures related to environmental projects at OG&E.

The decrease of $59.0 million, or 10.6 percent, in net cash used in investing activities in 2015 as compared to 2014 was primarily due to an increase in investments related to return of capital from Enable and a decrease in capital expenditures related to transmission projects completed in 2014 partially offset by an increase in capital expenditures related to environmental projects at OG&E.

Financing Activities

The decrease of $196.5 million, or 66.5 percent, in net cash used in financing activities in 2016 as compared to 2015 was primarily due to an increase in short-term debt partially offset by the payment of $110.0 million in long-term debt during the first quarter of 2016.

The increase of $131.8 million, or 80.5 percent, in net cash used in financing activities in 2015 as compared to 2014 was primarily due to the issuance of long-term debt during 2014 and an increase in dividends paid in 2015, which was partially offset by a decrease in short-term debt and the payment of $240.0 million in long-term debt during the third quarter of 2014.

Future Capital Requirements and Financing Activities

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2017 through 2021 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects. Estimated capital expenditures for Enable are not included in the table below.

(In millions)	2017	2018	2019	2020	2021
OG&E Base Transmission	$ 35	$ 30	$ 30	$ 30	$ 30
OG&E Base Distribution	195	175	175	175	175
OG&E Base Generation	40	75	75	75	75
OG&E Other	35	25	25	25	25
Total Base Transmission, Distribution, Generation and Other	305	305	305	305	305
OG&E Known and Committed Non-Base Projects:					
Transmission Projects:					
Other Regionally Allocated Projects (A)	50	20	20	20	20
Large SPP Integrated Transmission Projects (B) (C)	155	20	—	—	—
Total Transmission Projects	205	40	20	20	20
Other Projects:					
Solar	20	—	—	—	—
Environmental - low NO_X burners (D)	15	—	—	—	—
Environmental - Dry Scrubbers (D)	160	95	15	—	—
Combustion turbines - Mustang	170	35	—	—	—
Environmental - natural gas conversion (D)	20	25	25	—	—
Allowance of funds used during construction and ad valorem taxes	55	40	5	—	—
Total Other Projects	440	195	45	—	—
Total Known and Committed Non-Base Projects	645	235	65	20	20
Total	$ 950	$ 540	$ 370	$ 325	$ 325

(A) Typically 100kV to 299kV projects. Approximately 30 percent of revenue requirement allocated to SPP members other than OG&E.
(B) Typically 300kV and above projects. Approximately 85 percent of revenue requirement allocated to SPP members other than OG&E.

(C)

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Integrated Transmission Project	30 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation. $5.0 million of the estimated cost has been spent prior to 2017.	$45	Late 2017
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation and construction of the Mathewson substation on this transmission line. $50.0 million of the estimated cost associated with the Mathewson to Cimarron line and substations went into service in 2016; $55.0 million has been spent prior to 2017.	$185	Mid 2018

(D) Represent capital costs associated with OG&E’s ECP to comply with the EPA’s MATS and Regional Haze Rule. More detailed discussion regarding Regional Haze Rule and OG&E’s ECP can be found in Note 14 and under "Environmental Laws and Regulations" within "Management's Discussion and Analysis of Financial Condition and Results of Operations" under Part II, Item 7 of this Form 10-K.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets will be evaluated based upon their impact upon achieving the Company's financial objectives.

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2016. See the Company's Consolidated Statements of Capitalization and Note 13 for additional information.

(In millions)	2017	2018-2019	2020-2021	After 2021	Total
Maturities of long-term debt (A)	$ 225.2	$ 500.2	$ 0.2	$ 1,929.7	$ 2,655.3
Operating lease obligations					
Railcars	2.7	22.7	—	—	25.4
Wind farm land leases	2.5	5.0	5.8	43.5	56.8
Noncancellable operating lease	0.8	0.7	—	—	1.5
Total operating lease obligations	6.0	28.4	5.8	43.5	83.7
Other purchase obligations and commitments					
Cogeneration capacity and fixed operation and maintenance payments	77.1	140.4	105.7	48.8	372.0
Expected cogeneration energy payments	37.7	76.4	85.1	49.9	249.1
Minimum fuel purchase commitments	236.2	85.5	49.2	407.2	778.1
Expected wind purchase commitments	59.0	114.5	114.6	583.5	871.6
Long-term service agreement commitments	2.2	50.6	4.8	120.6	178.2
Mustang Modernization expenditures	130.4	21.9	—	—	152.3
Environmental compliance plan expenditures	169.2	71.9	0.2	—	241.3
Total other purchase obligations and commitments	711.8	561.2	359.6	1,210.0	2,842.6
Total contractual obligations	943.0	1,089.8	365.6	3,183.2	5,581.6
Amounts recoverable through fuel adjustment clause (B)	(335.6)	(299.1)	(248.9)	(1,040.6)	(1,924.2)
Total contractual obligations, net	$ 607.4	$ 790.7	$ 116.7	$ 2,142.6	$ 3,657.4

(A) Maturities of the Company's long-term debt during the next five years consist of $225.2 million, $250.1 million, $250.1 million, $0.1 million and $0.1 million in years 2017, 2018, 2019, 2020 and 2021, respectively.
(B) Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's expected cogeneration energy payments, OG&E's minimum fuel purchase commitments and OG&E's expected wind purchase commitments.

OG&E also has 440 MWs of QF contracts to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates.

The actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases shown above) and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of minimum fuel purchase commitments of OG&E noted above may increase capital requirements, such costs are recoverable through fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The fuel adjustment clauses are subject to periodic review by the OCC and the APSC.

Pension and Postretirement Benefit Plans

At December 31, 2016, 39.8 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in corporate fixed income, other securities and U.S. treasury notes and bonds as presented in Note 11. During 2016, actual returns on the Pension Plan were $48.0 million, slightly higher than the expected return on plan assets of $41.5 million. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, remained unchanged. The level of funding is dependent on returns on plan assets and future discount rates. During 2016, the Company made a $20.0 million contribution to its Pension Plan. During 2015, the Company did not make any contributions to its Pension Plan. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2017. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2016 and 2015. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheets. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2016**	2015	**2016**	2015	**2016**	2015
Benefit obligations	**$ 672.2**	$ 680.0	**$ 7.0**	$ 25.1	**$ 215.9**	$ 225.3
Fair value of plan assets	**595.9**	581.7	**—**	—	**53.1**	55.3
Funded status at end of year	**$ (76.3)**	$ (98.3)	**$ (7.0)**	$ (25.1)	**$ (162.8)**	$ (170.0)

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost. During the quarter ended June 30, 2016, the Company experienced a settlement of its Supplemental Executive Retirement Plan and its non-qualified Restoration of Retirement Income Plan. As a result, the Company recorded pension settlement charges of $8.6 million during 2016. During 2015, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments paid to such employees upon retirement. As a result, the Company recorded pension settlement charges of $16.2 million in the third quarter of 2015 and $5.5 million in the fourth quarter of 2015. The pension settlement charges did not increase the Company's total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods.

Common Stock Dividends

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The Company's financial objective includes dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets and the composition of the Company's assets and investment opportunities. At the Company's September 2016 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.30250 per share from $0.27500 per share effective in October 2016.

Security Ratings

	Moody's Investors Services	Standard & Poor's Ratings Services	Fitch Ratings
OG&E Senior Notes	A1	A-	A+
OGE Energy Senior Notes	A3	BBB+	A-
OGE Energy Commercial Paper	P2	A2	F2

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, commodity prices, acquisitions of other businesses and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

2016 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $770.3 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $82.6 million resulting in total net capital requirements and contractual obligations of $852.9 million in 2016, of which $135.8 million was to comply with environmental regulations. This compares to net capital requirements of $548.0 million and net contractual obligations of $85.6 million totaling $633.6 million in 2015, of which $130.6 million was to comply with environmental regulations.

In 2016, the Company's sources of capital were cash generated from operations, proceeds from the issuance of short-term debt, and distributions from Enable. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection from customers and fuel inventories. See "Working Capital" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

The Dodd-Frank Act

Derivative instruments have been used at times in managing OG&E's commodity price exposure. The Dodd-Frank Act, among other things, provides for regulation by the Commodity Futures Trading Commission of certain commodity-related contracts. Although OG&E qualifies for an end-user exception from mandatory clearing of commodity-related swaps, these regulations could affect the ability of OG&E to participate in these markets and could add additional regulatory oversight over its contracting activities.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. The Company has revolving credit facilities totaling in the aggregate $1,150.0 million. These bank facilities can also be used as letter of credit facilities. As of December 31, 2016, the Company had $236.2 million in short-term debt compared to no balance at December 31, 2015. The average balance of short-term debt in 2016 was $216.7 million at a weighted-average interest rate of 0.79 percent. The maximum month-end balance of short-term debt in 2016 was $355.6 million. At December 31, 2016, the Company had $912.0 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2017 and ending December 31, 2018. At December 31, 2016, the Company had $0.3 million in cash and cash equivalents. See Note 10 for a discussion of the Company's short-term debt activity.

In December 2011, the Company and OG&E entered into unsecured revolving credit agreements in the aggregate of $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E) which expire in December 2018. The Company and OG&E expect to replace the existing agreements with new revolving credit agreements during 2017, under terms and conditions generally similar to the existing agreements.

Expected Issuance of Long-Term Debt

OG&E expects to issue $300.0 million of long-term debt during the first half of 2017, depending on market conditions, to fund capital expenditures, to repay short or long-term borrowings and for general corporate purposes.

Common Stock

The Company does not expect to issue any common stock in 2017 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 8 for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable Limited Partnership Agreement, Enable made distributions of $141.2 million, $139.3 million and $143.7 million, to the Company during the years ended December 31, 2016, 2015 and 2014, respectively. On June 22, 2016, Enable's Limited Partnership Agreement was amended to change the last permitted distribution date from 45 days to 60 days after the close of each quarter. Enable's General Partner Agreement was amended to change the distribution deadline from 50 days after the close of each quarter to five days following distributions by Enable.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised includes the determination of Pension Plan assumptions, income taxes, contingency reserves, asset retirement obligations and depreciable lives of property, plant and equipment. For the electric utility segment, significant judgment is also exercised in the determination of regulatory assets and liabilities and unbilled revenues. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective or complex judgments or estimates, in Note 1.

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers a significant amount of the Company's employees hired before December 1, 2009. Effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover a significant amount of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The Pension Plan rate assumptions are shown in Note 11. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the Pension Plan. The following table indicates the sensitivity of the Pension Plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 1 percent	+/- $6.0 million
Discount rate	+/- 0.25 percent	+/- $14.8 million
Contributions	+/- $10 million	+/- $10.0 million

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Accordingly, it is necessary to make judgments regarding income tax exposure. As a result, changes in these judgments can materially affect amounts the Company recognized in its consolidated financial statements. Tax positions taken by the Company on its income tax returns that are recognized in the financial statements must satisfy a more likely than not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being accreted over their respective lives ranging from three to 74 years. The inputs used in the valuation of asset retirement obligations include the assumed life of the asset placed into service, the average inflation rate, market risk premium, the credit-adjusted risk free interest rate and the timing of incurring costs related to the retirement of the asset.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates. The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss and prior service cost.

Unbilled Revenues

OG&E recognizes revenue from electric sales when power is delivered to customers. OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. OG&E accrues an estimate of the revenues for electric sales delivered since the latest billings. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2016, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of $0.4 million. At December 31, 2016 and 2015, Accrued Unbilled Revenues were $59.7 million and $53.5 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. At December 31, 2016, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.1 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance

Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.5 million and $1.4 million at December 31, 2016 and 2015, respectively.

Accounting Pronouncements

See Note 2 for discussion of current accounting pronouncements that are applicable to the Company.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on available information, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Notes 13 and 14 and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of the Company are subject to numerous stringent and complex Federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways including the handling or disposal of waste material, future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. Historically, OG&E's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2017 will be $241.3 million, of which $221.9 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2018 will be approximately $180.8 million, of which $161.6 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NO_X burners, Dry Scrubbers and gas conversions.

Air

Federal Clean Air Act Overview

OG&E’s operations are subject to the Federal Clean Air Act as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. OG&E likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Regional Haze Control Measures

The EPA's 2005 Regional Haze Rule is intended to protect visibility in certain national parks and wilderness areas throughout the United States that may be impacted by air pollutant emissions. On December 28, 2011, the EPA issued a final Regional Haze

Rule for Oklahoma which adopted a FIP for SO_2 emissions at Sooner Units 1 and 2 and Muskogee Units 4 and 5. The FIP compliance date is now January 4, 2019 as a result of the appeal filed by OG&E and others.

OG&E's current strategy for satisfying the FIP includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. As described in Note 14, the OCC has approved the Company's decision to install Dry Scrubbers at the Sooner units. As of December 31, 2016, OG&E has incurred $208.7 million of construction work in progress on the Dry Scrubbers.

Cross-State Air Pollution Rule

In August 2011, the EPA finalized its CSAPR that required several states in the eastern half of the United States to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. Litigation challenging the rule prevented it from entering into effect until 2014. Several parties to that litigation, including OG&E, have petitions for review that remain pending although the rule is now effective. Compliance with the CSAPR began in 2015 using the amount of allowances originally scheduled to be available in 2012. As of December 31, 2016, OG&E has installed six low NO_X burner systems on two Muskogee units, two Sooner units and two Seminole units and is in compliance. Installation of the final low NO_X burner system is scheduled during the first quarter of 2017 on the remaining Seminole unit.

On September 7, 2016, the EPA finalized an update to the 2011 CSAPR. The new rule applies to ozone-season NO_X in 22 eastern states (including Oklahoma), utilizes a cap and trade program for NO_X emissions and will take effect on May 1, 2017. The rule reduces the 2016 CSAPR emissions cap for all seven of OG&E’s coal and gas facilities by 47 percent combined. On December 23, 2016, OG&E filed a petition for reconsideration of the 2016 rule with the EPA. OG&E is asking the agency to reconsider the methodology used to calculate state ozone-season emissions budgets. OG&E's petition, along with petitions for reconsideration filed by various other parties, is currently pending. Also on December 23, 2016, OG&E filed a petition for review of the 2016 rule in the Unites States Court of Appeals for the District of Columbia Circuit, asking the court to set aside the rule on the grounds that it is arbitrary, capricious, an abuse of the EPA's discretion and not otherwise in accordance with the law. OG&E's case has been consolidated with several other petitions for review, all of which are currently pending.

Due to the pending litigation and administrative proceedings, the ultimate timing and impact of the 2016 CSAPR update rule on our operations cannot be determined with certainty at this time. However, the Company does not anticipate additional capital expenditures beyond what has already been disclosed, and does not expect that the reduced emissions cap, if upheld, will have a material impact on the Company’s consolidated financial position, results of operations or cash flows.

Hazardous Air Pollutants Emission Standards

On February 16, 2012, the EPA published the final MATS rule regulating the emissions of certain hazardous air pollutants from electric generating units, which became effective April 16, 2012. The Company believes that it complied with the MATS rule by the April 16, 2016 deadline that applied to OG&E. Nonetheless, there is continuing litigation, to which the Company is not a party, challenging whether the EPA had statutory authority to issue the MATS rule.

National Ambient Air Quality Standards

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, the Company could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS. As of the end of 2016, no areas of Oklahoma had been designated as non-attainment for pollutants that are likely to affect the Company's operations. Several processes are under way to designate areas in Oklahoma as attaining or not attaining revised NAAQS. The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

The EPA proposed to designate part of Muskogee County in which OG&E's Muskogee Power Plant is located, as non-attainment for the 2010 SO_2 NAAQS on March 1, 2016, even though nearby monitors indicate compliance with the NAAQS. The proposed designation is based on modeling that does not reflect the planned conversion of two of the coal units at Muskogee to natural gas. OG&E commented that the EPA should defer a designation of the area to allow time for additional monitoring. The EPA has a deadline for making a decision on the designation pursuant to a consent decree entered by the U.S. District Court for the Northern District of California to resolve a citizen suit. The deadline has been extended several times, with the current deadline being February 27, 2017. The EPA has published final decisions on all other areas of Oklahoma. In this decision, Noble County, in which the Sooner plant is located, was deemed to be in attainment with the 2010 standard. At this time, OG&E cannot determine with any certainty whether this determination will cause a material impact to the Company's financial results.

On September 30, 2015 the EPA finalized a NAAQS for ozone at 70 ppb, which is more stringent than the previous standard of 75 ppb, set in 2008. In September 2016, Governor Mary Fallin submitted to the EPA the recommendation of "attainment/unclassifiable" for all 77 counties in Oklahoma. This recommendation is subject to approval by the EPA.

The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

Climate Change and Greenhouse Gas Emissions

There is continuing discussion and evaluation of possible global climate change in certain regulatory and legislative arenas. The focus is generally on emissions of greenhouse gases, including CO_2, sulfur hexafluoride and methane, and whether these emissions are contributing to the warming of the earth's atmosphere. In December 2015, as part of the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change, the United States committed to reduce economy wide emissions by 26 percent to 28 percent below 2005 emission levels. This multinational agreement became open for signing on April 22, 2016 and will require countries to review and "represent a progression" every five years beginning in 2020. The agreement could result in future additional emissions reductions in the United States, however, it is not possible to determine what the international legal standards for greenhouse gas emissions will be in the future and the extent to which commitments under the December 2015 Paris Agreement will be implemented through the Clean Air Act, other than existing statutes and new legislation.

If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of CO_2 and other greenhouse gases on the Company's facilities, this could result in significant additional compliance costs that would affect the Company’s future financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Several states outside the area where the Company operates have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs.

On October 23, 2015, the EPA published the final Clean Power Plan that established standards of performance for CO_2 emissions from existing fossil-fuel-fired power plants along with state-specific CO_2 reduction standards expressed as both rate-based (lbs/MWh) and mass-based (tons/yr) goals. The 2030 rate-based reduction requirement for all existing generating units in Oklahoma has decreased from a proposed 43 percent reduction to 32 percent in the final rule. The mass-based approach for existing units calls for a 24 percent reduction by 2030 in Oklahoma.

A number of states, including Oklahoma, filed lawsuits against the Clean Power Plan. On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan pending resolution of challenges to the rule. The Company is unable to determine what impact the lawsuits will ultimately have on the Clean Power Plan or what impact the stay in implementation will have; however, if the Clean Power Plan survives judicial review and is implemented as written, it could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Due to the pending litigation and the uncertainties in the state approaches, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time.

Nonetheless, OG&E’s current business strategy will result in a reduced carbon emissions rate compared to current levels. As discussed in "Pending Regulatory Matters," OG&E has filed an application with the OCC for approval of its plan to comply with the EPA’s MATS and Regional Haze Rule FIP by converting two coal-fired generating units at Muskogee Station to natural gas, among other measures. OG&E’s deployment of Smart Grid technology helps to reduce the peak load demand. OG&E also seeks to utilize renewable energy sources that do not emit greenhouse gases. OG&E's service territory borders one of the nation's best wind resource areas. OG&E has leveraged its geographic position to develop renewable energy resources and completed transmission investments to deliver the renewable energy. The SPP has begun to authorize the construction of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas Panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery limitations.

EPA Startup, Shutdown, and Malfunction Policy

On May 22, 2015, the EPA issued a final rule to address the outdated provisions in the SIP of 36 states, including Oklahoma, regarding the treatment of emissions that occur during startup, shutdown and malfunction operations. The final rule clarifies the EPA's Startup, Shutdown and Malfunction Policy to assure consistency with the Clean Air Act and other recent court decisions. The ODEQ submitted a SIP revision for the EPA's approval on November 7, 2016 to comply with this rule. Although the extent of impact is not known, this rule will impact certain OG&E units.

Endangered Species

Certain Federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas become subject to protection, the Company’s operations and development projects, particularly transmission, wind or pipeline projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures.

In 2014, the Company enrolled in the Western Association of Fish and Wildlife Agencies range-wide conservation plan which consists of industry-specific conservation practices that apply to projects and activities in the impacted area. The range-wide conservation plan was approved by the U.S. Fish and Wildlife Service and incorporated as part of the agency’s final decision on March 27, 2014 to list the lesser prairie chicken as a threatened species. On September 1, 2015, the U.S. District Court Western District of Texas vacated federal protections for the lesser prairie chicken based on the U.S. Fish and Wildlife Service's failure to thoroughly consider the active conservation efforts in making the listing decision. On July 19, 2016, the U.S. Fish and Wildlife Service issued a final rule to amend its regulations to remove the lesser prairie chicken from the list of threatened species under the Endangered Species Act. On September 8, 2016, WildEarth Guardians, Defenders of Wildlife and the Center for Biological Diversity filed a petition with the U.S. Fish and Wildlife Services to list the lesser prairie chicken as "endangered" under the Endangered Species Act. On November 30, 2016, the U.S. Fish and Wildlife Services published a notice in the Federal Register announcing its finding that the September 2016 petition presents information indicating that listing of the lesser prairie-chicken may be warranted. The agency has initiated a 12-month status review. OG&E will continue to monitor the progress of the petition.

Air Quality Control System

On September 10, 2014, OG&E executed a contract for the design, engineering and fabrication of two circulating Dry Scrubber systems to be installed at Sooner Units 1 and 2. OG&E entered into an agreement on February 9, 2015, to install the Dry Scrubber systems. The Dry Scrubbers are scheduled to be completed by 2019. More detail regarding the ECP can be found under the "Pending Regulatory Matters" section of "Notes to Consolidated Financial Statements" of Part II, Item 8 of this Form 10-K.

Waste

OG&E's operations generate wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 as well as comparable state laws which impose detailed requirements for the handling, storage, treatment and disposal of waste.

On December 19, 2014, the EPA finalized a rule under the Federal Resource Conservation and Recovery Act for the handling and disposal of coal combustion residuals or coal ash. The final rule regulates coal ash as a solid waste rather than a hazardous waste, which would have made the management of coal ash more costly. The final rule is currently being appealed at the D.C. Circuit Court of Appeals. OG&E is in compliance with this rule at this time.

The Company has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2016, the Company obtained refunds of $1.9 million from the recycling of scrap metal, salvaged transformers and used transformer oil. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

OG&E's operations are subject to the Federal Clean Water Act, and comparable state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and Federal waters.

The EPA issued a final rule on May 19, 2014 to implement Section 316(b) of the Federal Clean Water Act, which requires that power plant cooling water intake structure location, design, construction and capacity reflect the best available technology for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. OG&E submitted compliance plans to the state in April 2015. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation following issuance of the permits from the state.

On September 30, 2015, the EPA issued a final rule addressing the effluent limitation guidelines for power plants under the Federal Clean Water Act. The final rule establishes technology and performance based standards that may apply to discharges of six waste streams including bottom ash transport water. Compliance with this rule occurs between 2018 and 2023. OG&E is evaluating what if any compliance actions are needed but is not able to quantify with any certainty, what costs may be incurred. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation following issuance of the permits from the state.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E utilizes various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to OG&E.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 13.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

Risk Oversight Committee

Management monitors market risks using a risk committee structure. The Company's Risk Oversight Committee, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all market risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. On a quarterly basis, the Risk Oversight Committee reports to the Audit Committee of the Company's Board of Directors on the Company's risk profile affecting anticipated financial results, including any significant risk issues.

The Company also has a Corporate Risk Management Department. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company's risk policies.

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the Audit Committee of the Company's Board of Directors and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to market risk management are being followed.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio, but the Company has no intent at this time to utilize interest rate derivatives.

The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities or by calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

Year ended December 31 *(Dollars in millions)*	2017	2018	2019	2020	2021	Thereafter	Total	12/31/16 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 125.2	$ 250.1	$ 250.1	$ 0.1	$ 0.1	$ 1,794.3	$ 2,419.9	$ 2,668.5
Weighted-average interest rate	6.50%	6.35%	8.25%	3.01%	3.01%	5.19%	5.70%	
Variable-rate debt (B)								
Principal amount	$ 100.0	$ —	$ —	$ —	$ —	$ 135.4	$ 235.4	$ 235.3
Weighted-average interest rate	1.47%	—%	—%	—%	—%	0.76%	1.06%	

(A) Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.

(B) A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $2.4 million annually through 2017 and $1.4 million thereafter.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions except per share data)*	**2016**	2015	2014
OPERATING REVENUES	**$ 2,259.2**	$ 2,196.9	$ 2,453.1
COST OF SALES	**880.1**	865.0	1,106.6
OPERATING EXPENSES			
Other operation and maintenance	**465.6**	451.6	439.6
Depreciation and amortization	**322.6**	307.9	281.4
Taxes other than income	**87.6**	91.2	88.7
Total operating expenses	**875.8**	850.7	809.7
OPERATING INCOME	**503.3**	481.2	536.8
OTHER INCOME (EXPENSE)			
Equity in earnings of unconsolidated affiliates	**101.8**	15.5	172.6
Allowance for equity funds used during construction	**14.2**	8.3	4.2
Other income	**26.0**	27.0	17.8
Other expense	**(16.9)**	(14.3)	(14.4)
Net other income (expense)	**125.1**	36.5	180.2
INTEREST EXPENSE			
Interest on long-term debt	**143.2**	147.8	144.6
Allowance for borrowed funds used during construction	**(7.5)**	(4.2)	(2.4)
Interest on short-term debt and other interest charges	**6.4**	5.4	6.2
Interest expense	**142.1**	149.0	148.4
INCOME BEFORE TAXES	**486.3**	368.7	568.6
INCOME TAX EXPENSE	**148.1**	97.4	172.8
NET INCOME	**$ 338.2**	$ 271.3	$ 395.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**199.7**	199.6	199.2
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**199.9**	199.6	199.9
BASIC EARNINGS PER AVERAGE COMMON SHARE	**$ 1.69**	$ 1.36	$ 1.99
DILUTED EARNINGS PER AVERAGE COMMON SHARE	**$ 1.69**	$ 1.36	$ 1.98
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.15500**	$ 1.05000	$ 0.95000

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2016**	2015	2014
Net income	**$ 338.2**	$ 271.3	$ 395.8
Other comprehensive income (loss), net of tax			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $1.7, $2.2 and $1.2, respectively	**2.8**	2.5	1.8
Net loss arising during the period, net of tax of ($0.6), ($5.8) and ($7.0), respectively	**(0.7)**	(9.5)	(11.1)
Settlement cost, net of tax of $3.2, $2.9 and ($0.1), respectively	**5.0**	4.6	(0.1)
Postretirement Benefit Plans:			
Amortization of deferred net loss, net of tax of $0, $0.8 and $0.5, respectively	**—**	1.2	0.9
Net gain (loss) arising during the period, net of tax of $0.1, $5.6 and ($1.9), respectively	**0.2**	9.3	(3.1)
Amortization of prior service cost, net of tax of ($1.0), ($1.1) and ($1.1), respectively	**(1.5)**	(1.8)	(1.8)
Amortization of deferred interest rate swap hedging losses, net of tax of $0, $0 and $0.1, respectively	**—**	—	0.2
Other comprehensive income (loss), net of tax	**5.8**	6.3	(13.2)
Comprehensive income	**$ 344.0**	$ 277.6	$ 382.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2016**	2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 338.2**	$ 271.3	$ 395.8
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**322.6**	307.9	281.4
Deferred income taxes and investment tax credits	**153.8**	102.6	177.3
Equity in earnings of unconsolidated affiliates	**(101.8)**	(15.5)	(172.6)
Distributions from unconsolidated affiliates	**102.3**	94.1	143.7
Allowance for equity funds used during construction	**(14.2)**	(8.3)	(4.2)
Stock-based compensation	**4.6**	5.9	(2.7)
Regulatory assets	**(21.4)**	(9.1)	4.5
Regulatory liabilities	**(11.8)**	(27.5)	(4.4)
Other assets	**15.4**	10.4	(16.5)
Other liabilities	**(18.9)**	8.6	29.6
Change in certain current assets and liabilities			
Accounts receivable, net	**0.1**	15.7	(9.4)
Accounts receivable - unconsolidated affiliates	**(0.8)**	3.9	6.8
Accrued unbilled revenues	**(6.2)**	2.0	3.2
Income taxes receivable	**(2.2)**	(1.2)	(10.4)
Fuel, materials and supplies inventories	**32.4**	(56.5)	20.4
Fuel clause under recoveries	**(51.3)**	68.3	(42.1)
Other current assets	**(26.2)**	(17.2)	(2.6)
Accounts payable	**(45.1)**	30.9	(64.0)
Fuel clause over recoveries	**(61.3)**	61.3	(0.4)
Other current liabilities	**36.4**	17.8	(11.8)
Net Cash Provided from Operating Activities	**644.6**	865.4	721.6
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(660.1)**	(547.8)	(569.3)
Return of capital - equity method investments	**38.8**	45.2	9.5
Proceeds from sale of assets	**0.9**	2.5	0.7
Net Cash Used in Investing Activities	**(620.4)**	(500.1)	(559.1)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**—**	—	588.9
Issuance of common stock	**—**	7.2	13.2
Dividends paid on common stock	**(225.1)**	(204.6)	(184.1)
Payment of long-term debt	**(110.2)**	(0.2)	(240.2)
Increase (decrease) in short-term debt	**236.2**	(98.0)	(341.6)
Net cash used in financing activities	**(99.1)**	(295.6)	(163.8)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**(74.9)**	69.7	(1.3)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**75.2**	5.5	6.8
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 0.3**	$ 75.2	$ 5.5

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2016**	2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 0.3**	$ 75.2
Accounts receivable, less reserve of $1.5 and $1.4, respectively	**173.0**	173.1
Accounts receivable - unconsolidated affiliates	**2.5**	1.7
Accrued unbilled revenues	**59.7**	53.5
Income taxes receivable	**19.4**	17.2
Fuel inventories	**79.8**	113.8
Materials and supplies, at average cost	**81.7**	80.1
Fuel clause under recoveries	**51.3**	—
Other	**81.8**	55.6
Total current assets	**549.5**	570.2
OTHER PROPERTY AND INVESTMENTS		
Investment in unconsolidated affiliates	**1,158.6**	1,194.4
Other	**73.6**	70.7
Total other property and investments	**1,232.2**	1,265.1
PROPERTY, PLANT AND EQUIPMENT		
In service	**10,690.0**	10,318.3
Construction work in progress	**495.1**	278.5
Total property, plant and equipment	**11,185.1**	10,596.8
Less accumulated depreciation	**3,488.9**	3,274.4
Net property, plant and equipment	**7,696.2**	7,322.4
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**404.8**	402.2
Other	**56.9**	20.7
Total deferred charges and other assets	**461.7**	422.9
TOTAL ASSETS	**$ 9,939.6**	$ 9,580.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2016**	2015
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 236.2**	$ —
Accounts payable	**205.4**	262.5
Dividends payable	**60.4**	54.9
Customer deposits	**77.7**	77.0
Accrued taxes	**41.3**	45.9
Accrued interest	**40.4**	42.9
Accrued compensation	**45.1**	54.4
Long-term debt due within one year	**224.7**	110.0
Fuel clause over recoveries	**—**	61.3
Other	**96.0**	43.9
Total current liabilities	**1,027.2**	752.8
LONG-TERM DEBT	**2,405.8**	2,628.8
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**274.8**	299.9
Deferred income taxes	**2,334.5**	2,178.2
Regulatory liabilities	**299.7**	273.6
Other	**153.8**	121.3
Total deferred credits and other liabilities	**3,062.8**	2,873.0
Total liabilities	**6,495.8**	6,254.6
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**1,105.8**	1,101.3
Retained earnings	**2,367.3**	2,259.8
Accumulated other comprehensive loss, net of tax	**(29.3)**	(35.1)
Total stockholders' equity	**3,443.8**	3,326.0
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 9,939.6**	$ 9,580.6

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*			**2016**		2015
STOCKHOLDERS' EQUITY					
Common stock, par value $0.01 per share; authorized 450.0 shares; and outstanding 199.7 shares and 199.7 shares, respectively		**$**	**2.0**	$	2.0
Premium on common stock			**1,103.8**		1,099.3
Retained earnings			**2,367.3**		2,259.8
Accumulated other comprehensive loss, net of tax			**(29.3)**		(35.1)
Total stockholders' equity			**3,443.8**		3,326.0
LONG-TERM DEBT					
SERIES	DUE DATE				
Senior Notes - OGE Energy					
1.38%	Variable Senior Notes, Series Due November 24, 2017		**100.0**		100.0
Senior Notes - OG&E					
5.15%	Senior Notes, Series Due January 15, 2016		**—**		110.0
6.50%	Senior Notes, Series Due July 15, 2017		**125.0**		125.0
6.35%	Senior Notes, Series Due September 1, 2018		**250.0**		250.0
8.25%	Senior Notes, Series Due January 15, 2019		**250.0**		250.0
6.65%	Senior Notes, Series Due July 15, 2027		**125.0**		125.0
6.50%	Senior Notes, Series Due April 15, 2028		**100.0**		100.0
5.75%	Senior Notes, Series Due January 15, 2036		**110.0**		110.0
6.45%	Senior Notes, Series Due February 1, 2038		**200.0**		200.0
5.85%	Senior Notes, Series Due June 1, 2040		**250.0**		250.0
5.25%	Senior Notes, Series Due May 15, 2041		**250.0**		250.0
3.90%	Senior Notes, Series Due May 1, 2043		**250.0**		250.0
4.55%	Senior Notes, Series Due March 15, 2044		**250.0**		250.0
4.00%	Senior Notes, Series Due December 15, 2044		**250.0**		250.0
3.70%	Tinker Debt, Due August 31, 2062		**9.9**		10.0
Other Bonds - OG&E					
0.05% - 0.90%	Garfield Industrial Authority, January 1, 2025		**47.0**		47.0
0.07% - 0.83%	Muskogee Industrial Authority, January 1, 2025		**32.4**		32.4
0.05% - 0.86%	Muskogee Industrial Authority, June 1, 2027		**56.0**		56.0
Unamortized debt expense			**(15.5)**		(16.8)
Unamortized discount			**(9.3)**		(9.8)
Total long-term debt			**2,630.5**		2,738.8
Less long-term debt due within one year			**(224.7)**		(110.0)
Total long-term debt (excluding debt due within one year)			**2,405.8**		2,628.8
Total Capitalization (including long-term debt due within one year)		**$**	**6,074.3**	$	6,064.8

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In millions)	Common Stock	Premium on Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2013	$ 2.0	$ 1,071.6	$ 1,991.7	$ (28.2)	$ 3,037.1
Net income	—	—	395.8	—	395.8
Other comprehensive income, net of tax	—	—	—	(13.2)	(13.2)
Dividends declared on common stock	—	—	(189.3)	—	(189.3)
Issuance of common stock	—	13.2	—	—	13.2
Stock-based compensation	—	0.8	—	—	0.8
Balance at December 31, 2014	$ 2.0	$ 1,085.6	$ 2,198.2	$ (41.4)	$ 3,244.4
Net income	—	—	271.3	—	271.3
Other comprehensive income, net of tax	—	—	—	6.3	6.3
Dividends declared on common stock	—	—	(209.7)	—	(209.7)
Issuance of common stock	—	7.2	—	—	7.2
Stock-based compensation	—	6.5	—	—	6.5
Balance at December 31, 2015	$ 2.0	$ 1,099.3	$ 2,259.8	$ (35.1)	$ 3,326.0
Net income	**—**	**—**	**338.2**	**—**	**338.2**
Other comprehensive income, net of tax	**—**	**—**	**—**	**5.8**	**5.8**
Dividends declared on common stock	**—**	**—**	**(230.7)**	**—**	**(230.7)**
Stock-based compensation	**—**	**4.5**	**—**	**—**	**4.5**
Balance at December 31, 2016	**$ 2.0**	**$ 1,103.8**	**$ 2,367.3**	**$ (29.3)**	**$ 3,443.8**

The accompanying Notes to Consolidated Financial Statements are an integral part hereof.

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and it lacks the power to direct activities that most significantly impact economic performance.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory, and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

The natural gas midstream operations segment represents the Company's investment in Enable through wholly owned subsidiaries, and ultimately OGE Holdings. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation, principally located in the Williston basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company began accounting for its interest in Enable using the equity method of accounting.

The Company charges operating costs to OG&E and Enable based on several factors. Operating costs directly related to OG&E and Enable are assigned as such. Operating costs incurred for the benefit of OG&E and Enable are allocated either as overhead based primarily on labor costs or using the "Distrigas" method. The "Distrigas" method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted this method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities at:

December 31 *(In millions)*		**2016**		2015
Regulatory Assets				
Current				
Fuel clause under recoveries	**$**	**51.3**	$	—
Oklahoma demand program rider under recovery (A)		**51.0**		36.6
SPP cost tracker under recovery (A)		**10.0**		4.5
Other (A)		**9.5**		5.4
Total Current Regulatory Assets	**$**	**121.8**	$	46.5
Non-Current				
Benefit obligations regulatory asset	**$**	**232.6**	$	242.2
Income taxes recoverable from customers, net		**62.3**		56.7
Smart Grid		**43.2**		43.6
Deferred storm expenses		**35.7**		27.6
Unamortized loss on reacquired debt		**13.4**		14.8
Other		**17.6**		17.3
Total Non-Current Regulatory Assets	**$**	**404.8**	$	402.2
Regulatory Liabilities				
Current				
Fuel clause over recoveries	**$**	**—**	$	61.3
Other (B)		**12.3**		7.5
Total Current Regulatory Liabilities	**$**	**12.3**	$	68.8
Non-Current				
Accrued removal obligations, net	**$**	**262.8**	$	254.9
Pension tracker		**35.5**		17.7
Other (C)		**1.4**		1.0
Total Non-Current Regulatory Liabilities	**$**	**299.7**	$	273.6

(A) Included in Other Current Assets on the Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Consolidated Balance Sheets.
(C) Prior year amount of $1.0 million reclassified from Deferred Other Liabilities to Non-Current Regulatory Liabilities.

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances.

OG&E recovers program costs related to the Demand and Energy Efficiency Program. An extension of the demand program rider was approved in January 2016, which allows for the recovery through December 2018 of (i) demand program costs; (ii) lost revenues associated with certain achieved energy efficiency and demand savings; (iii) performance-based incentives; and (iv) costs associated with research and development investments.

OG&E recovers certain SPP costs related to base plan charges from its customers in Oklahoma through the SPP cost tracker.

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss and prior service cost. These expenses are recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to accumulated other comprehensive income.

The following table is a summary of the components of the benefit obligations regulatory asset at:

December 31 *(In millions)*	**2016**	2015
Pension Plan and Restoration of Retirement Income Plan		
Net loss	**$ 199.9**	$ 214.1
Postretirement Benefit Plans		
Net loss	**32.7**	34.2
Prior service cost	**—**	(6.1)
Total	**$ 232.6**	$ 242.2

The following amounts in the benefit obligations regulatory asset at December 31, 2016 are expected to be recognized as components of net periodic benefit cost in 2017:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	**$ 12.4**
Postretirement Benefit Plans	
Net loss	**2.3**
Total	**$ 14.7**

Income taxes recoverable from customers, which represents income tax benefits previously used to reduce OG&E's revenues, are treated as regulatory assets and are being amortized over the estimated remaining life of the assets to which they relate. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The income tax related regulatory assets and liabilities are netted in income taxes recoverable from customers, net in the regulatory assets and liabilities table above.

OG&E recovers the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program, the incremental costs for web portal access, education and providing home energy reports. These amounts are currently being recovered through a rate rider. Following a final order in the current Oklahoma general rate case, and review by the OCC Staff, the Oklahoma jurisdictional balance of the regulatory asset will be included in the fuel adjustment clause for final recovery. Costs not included in the rider are the incremental costs for web portal access, education and home energy reports, which are capped at $6.9 million, and the stranded costs associated with OG&E's analog electric meters, which have been replaced by smart meters and were accumulated during the smart grid deployment and have been included in the Smart Grid asset in the regulatory assets and liabilities table above. These costs are expected to be recovered in base rates upon final orders in the current general rate cases.

OG&E includes in expense any Oklahoma storm-related operation and maintenance expenses up to $2.7 million annually and defers any additional expenses incurred over $2.7 million. OG&E expects to recover the amounts deferred each year over a five-year period in accordance with historical practice.

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are recorded in interest expenses and are being amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is recovered as a part of OG&E's cost of capital.

Accrued removal obligations, net represent asset retirement costs previously recovered from ratepayers for other than legal obligations.

OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate cases. In accordance with approved orders, OG&E defers the difference between actual pension and postretirement medical expenses and the amount approved in its last Oklahoma rate case as a regulatory asset or regulatory liability. These amounts have been recorded in the Pension tracker regulatory liability in the regulatory assets and liabilities table above.

Management continuously monitors the future recoverability of regulatory assets. When, in management's judgment, future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If OG&E were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised includes the determination of Pension Plan assumptions, income taxes, contingency reserves, asset retirement obligations and depreciable lives of property, plant and equipment. For the electric utility segment, significant judgment is also exercised in the determination of regulatory assets and liabilities and unbilled revenues.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.5 million and $1.4 million at December 31, 2016 and 2015, respectively.

New business customers are required to provide a security deposit in the form of cash, bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers whose outside credit scores indicate an elevated risk are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

Fuel Inventories

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $82.4 million and $119.3 million at December 31, 2016 and 2015, respectively. Effective May 1, 2014, the gas storage services agreement with Enable was terminated. As a result of this contract termination, approximately 5.3 Bcf of cushion gas owned by OG&E and stored on the Enable system is being directed to OG&E's power plants over a five year period during peak time of June 1 to August 31 at a rate of 11,500 MMBtu/day for a total of 1.06 Bcf per year. In 2014, approximately $11.0 million of cushion gas was reclassified from Plant-in-Service to Other Deferred Assets, representing natural gas in storage, that will be removed from storage over four years. As of December 31, 2016, the balance of cushion gas in Fuel Inventories is $3.0 million and the balance in Other Deferred Assets is $2.7 million.

Property, Plant and Equipment

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The tables below present OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Plant, such as fuel, maintenance expense and other operating expenses, are included in the applicable financial statement captions in the Consolidated Statements of Income.

December 31, 2016 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	**77%**	**$ 234.2**	**$ 72.3**	**$ 161.9**
Redbud Plant (A)(B)	**51%**	**$ 489.0**	**$ 121.0**	**$ 368.0**

(A) Construction work in progress was $0.2 million and $1.8 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $45.3 million.

December 31, 2015 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	77%	$ 220.4	$ 62.8	$ 157.6
Redbud Plant (A)(B)	51%	$ 487.5	$ 101.2	$ 386.3

(A) Construction work in progress was $1.6 million and $1.3 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $39.8 million.

OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at:

December 31, 2016 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	**$ 117.7**	**$ 103.3**	**$ 14.4**
OGE Energy property, plant and equipment	**117.7**	**103.3**	**14.4**
OG&E			
Distribution assets	**3,896.2**	**1,221.5**	**2,674.7**
Electric generation assets (A)	**4,155.9**	**1,493.3**	**2,662.6**
Transmission assets (B)	**2,548.8**	**481.3**	**2,067.5**
Intangible plant	**85.0**	**43.9**	**41.1**
Other property and equipment	**381.5**	**145.6**	**235.9**
OG&E property, plant and equipment	**11,067.4**	**3,385.6**	**7,681.8**
Total property, plant and equipment	**$ 11,185.1**	**$ 3,488.9**	**$ 7,696.2**

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $45.3 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.6 million.

December 31, 2015 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$ 139.0	$ 112.7	$ 26.3
OGE Energy property, plant and equipment	139.0	112.7	26.3
OG&E			
Distribution assets	3,728.8	1,152.8	2,576.0
Electric generation assets (A)	3,837.4	1,407.0	2,430.4
Transmission assets (B)	2,454.2	440.7	2,013.5
Intangible plant	81.0	38.0	43.0
Other property and equipment	356.4	123.2	233.2
OG&E property, plant and equipment	10,457.8	3,161.7	7,296.1
Total property, plant and equipment	$ 10,596.8	$ 3,274.4	$ 7,322.4

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $39.8 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.5 million.

The following table summarizes the Company's unamortized computer software costs.

December 31 *(In millions)*	**2016**	2015
OGE Energy (holding company)	**$ 1.0**	$ 2.4
OG&E	**36.5**	34.3
Total	**$ 37.5**	$ 36.7

The following table summarizes the Company's amortization expense for computer software costs.

Year ended December 31 *(In millions)*	**2016**	2015	2014
OGE Energy (holding company)	**$ 1.4**	$ 2.0	$ 4.3
OG&E	**8.0**	6.9	5.2
Total	**$ 9.4**	$ 8.9	$ 9.5

Depreciation and Amortization

The provision for depreciation, which was 3.0 percent and 2.9 percent of the average depreciable utility plant for 2016 and 2015, respectively, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2017, the provision for depreciation is projected to be 3.1 percent of the average depreciable utility plant. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2016, 97.0 percent will be amortized over 16 years with the remaining 3.0 percent of the intangible plant balance at December 31, 2016 being amortized over 23.7 years. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which is being amortized over a 27 year life and $3.3 million for certain transmission substation facilities in OG&E's service territory, which are being amortized over a 37 to 59 year period.

Investment in Unconsolidated Affiliate

The Company's investment in Enable is considered to be a variable interest entity because the owners of the equity at risk in this entity have disproportionate voting rights in relation to their obligations to absorb the entity's expected losses or to receive its expected residual returns. However, the Company is not considered the primary beneficiary of Enable since it does not have the power to direct the activities that are considered most significant to the economic performance of Enable. The Company accounts for its investment in Enable using the equity method of accounting. Under the equity method, the investment will be adjusted each period for contributions made, distributions received and the Company's share of the investee's comprehensive income as adjusted for basis differences. The Company's maximum exposure to loss related to Enable is limited to the Company's equity investment in Enable as presented on the Company's Consolidated Balance Sheet at December 31, 2016. The Company evaluates its equity method investments for impairment when events or changes in circumstances indicate there is a loss in value of the investment that is other than a temporary decline.

The Company considers distributions received from Enable which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment and are classified as operating activities in the Consolidated Statements of Cash Flows. The Company considers distributions received from Enable in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment and are classified as investing activities in the Consolidated Statements of Cash Flows.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being accreted over their respective lives ranging from three to 74 years.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2016 and 2015.

(In millions)	**2016**	2015
Balance at January 1	**$ 63.3**	$ 58.6
Accretion expense	**2.8**	2.6
Revisions in estimated cash flows (A)	**3.6**	1.6
Additions	**—**	0.9
Liabilities settled	**(0.1)**	(0.4)
Balance at December 31	**$ 69.6**	$ 63.3

(A) Assumptions changed related to the estimated cost of asbestos abatement.

Allowance for Funds Used During Construction

Allowance for funds used during construction is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction, a non-cash item, is reflected as an increase to net Other Income and a reduction to Interest Expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction rates, compounded semi-annually, were 8.2 percent, 8.1 percent and 6.9 percent for the years ended December 31, 2016, 2015 and 2014, respectively. The increase in the allowance for funds used during construction rates in 2016 was primarily due to short-term debt being used to finance construction projects, which caused the debt portion of allowance for funds used during construction to increase.

Collection of Sales Tax

In the normal course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability for sales taxes when it bills its customers and eliminates this liability when the taxes are remitted to the appropriate governmental authorities. OG&E excludes the sales tax collected from its operating revenues.

Revenue Recognition

General

OG&E recognizes revenue from electric sales when power is delivered to customers. OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. OG&E accrues an estimate of the revenues for electric sales delivered since the latest billings. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority, but not ownership, of OG&E's transmission facilities to the SPP. The SPP has implemented FERC-approved regional day ahead and real-time markets for energy and operating services, as well as associated transmission congestion rights. Collectively the three markets operate together under the global name, SPP Integrated Marketplace. OG&E represents owned and contracted generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OG&E has not participated in the SPP Integrated Marketplace for any speculative trading activities. OG&E records the SPP Integrated Marketplace transactions as sales or purchases per FERC Order 668, which requires that purchases and sales be recorded on a net basis for each settlement period of the SPP Integrated Marketplace. These results are reported as Operating Revenues or Cost of Goods Sold in its Consolidated Financial Statements. OG&E revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operating and regulation by the FERC or the SPP.

Fuel Adjustment Clauses

The actual cost of fuel used in electric generation and certain purchased power costs are passed through to OG&E's customers through fuel adjustment clauses. The fuel adjustment clauses are subject to periodic review by the OCC and the APSC. The OCC and the APSC have the authority to review the appropriateness of gas transportation charges or other fees OG&E pays to its affiliate, Enable.

Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in Interest Expense and recognizes penalties in Other Expense in the Consolidated Statements of Income.

Accrued Vacation

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken.

Accumulated Other Comprehensive Income (Loss)

The following tables summarize changes in the components of accumulated other comprehensive loss attributable to OGE Energy during 2015 and 2016. All amounts below are presented net of tax.

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans		
(In millions)	Net income (loss)	Prior service cost	Net income (loss)	Prior service cost	Total
Balance at December 31, 2014	$ (36.8)	$ 0.1	$ (8.0)	$ 3.3	$ (41.4)
Other comprehensive income (loss) before reclassifications	(9.5)	—	9.3	—	(0.2)
Amounts reclassified from accumulated other comprehensive income (loss)	2.5	—	1.2	(1.8)	1.9
Settlement cost	4.6	—	—	—	4.6
Net current period other comprehensive income (loss)	(2.4)	—	10.5	(1.8)	6.3
Balance at December 31, 2015	(39.2)	0.1	2.5	1.5	(35.1)
Other comprehensive income (loss) before reclassifications	**(0.7)**	**—**	**0.2**	**—**	**(0.5)**
Amounts reclassified from accumulated other comprehensive income (loss)	**2.8**	**—**	**—**	**(1.5)**	**1.3**
Settlement cost	**5.0**	**—**	**—**	**—**	**5.0**
Net current period other comprehensive income (loss)	**7.1**	**—**	**0.2**	**(1.5)**	**5.8**
Balance at December 31, 2016	**$ (32.1)**	**$ 0.1**	**$ 2.7**	**$ —**	**$ (29.3)**

The following table summarizes significant amounts reclassified out of accumulated other comprehensive loss by the respective line items in net income during the years ended December 31, 2016 and 2015.

Details about Accumulated Other Comprehensive Income (Loss) Components	Amount Reclassified from Accumulated Other Comprehensive Income (Loss)		Affected Line Item in the Statement Where Net Income is Presented
	Year Ended December 31,		
(In millions)	**2016**	2015	
Amortization of defined benefit pension and restoration of retirement income plan items			
Actuarial losses	**$ (4.5)**	$ (4.7)	(A)
Settlement	**(8.2)**	(7.5)	(A)
	(12.7)	(12.2)	Total before tax
	(4.9)	(5.1)	Tax benefit
	$ (7.8)	$ (7.1)	Net of tax
Amortization of postretirement benefit plan items			
Actuarial losses	**$ —**	$ (2.0)	(A)
Prior service cost	**2.5**	2.9	(A)
	2.5	0.9	Total before tax
	1.0	0.3	Tax expense
	$ 1.5	$ 0.6	Net of tax
Total reclassifications for the period	**$ (6.3)**	$ (6.5)	Net of tax

(A) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost (see Note 11 for additional information).

The amounts in accumulated other comprehensive loss at December 31, 2016 that are expected to be recognized into earnings in 2017 are as follows:

(In millions)		
Pension Plan and Restoration of Retirement Income Plan		
Net loss	**$**	**(3.9)**
Postretirement Benefit Plans		
Net loss		**—**
Prior service cost		**—**
Total, net of tax	**$**	**(3.9)**

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E has been designated as one of several potentially responsible parties, the amount accrued represents OG&E's estimated share of the cost. The Company had $13.9 million and $10.0 million in accrued environmental liabilities at December 31, 2016 and 2015, respectively, which are included in the asset retirement obligations table.

Reclassifications

Certain prior-year amounts have been reclassified to conform to the current year presentation.

The December 31, 2015 Consolidated Balance Sheet has been adjusted for the reclassification of $16.8 million of debt issuance costs from Total Deferred Charges and Other Assets to Long-Term Debt to be consistent with the 2016 presentation due to the adoption of ASU 2015-03, "Simplifying the Presentation of Debt Issuance Costs," in 2016.

2. Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)." The new guidance was intended to be effective for fiscal years beginning after December 15, 2016. On July 9, 2015, the FASB decided to delay the effective date of the new revenue standard by one year. Reporting entities may choose to adopt the standard as of the original effective date. The deferral results in the new revenue standard being effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. The Company currently expects to apply the modified retrospective transition method, but will ultimately determine its transition approach once various industry issues have been resolved. Currently, the Company is not aware of any issues that would have a material impact on the timing of revenue recognition. The Company is assessing the impact of this new guidance on its tariff-based sales, contributions in aid of construction, bundled arrangements and alternative revenue programs. At this time, the Company is evaluating the impact of the new standard on its results of operations and financial position, but believes that it will change the income statement presentation of revenues and will require new disclosures.

***Consolidation*.** In February 2015, the FASB issued ASU 2015-02, "Consolidation (Topic 810)." The amendments in ASU 2015-02 affect reporting entities that are required to evaluate whether they should consolidate certain legal entities. The new standard modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities along with eliminating the presumption that a general partner should consolidate a limited partnership. The new standard is effective for fiscal years beginning after December 15, 2015. The adoption of this new standard did not result in the consolidation of any non-consolidated entities.

Leases. In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." The main difference between current lease accounting and Topic 842 is the recognition of right-of-use assets and lease liabilities by lessees for those leases classified as operating leases under current accounting guidance. Lessees, such as the Company, will need to recognize a right-of-use asset and a lease liability for virtually all of their leases, other than leases that meet the definition of a short-term lease. The liability will be equal to the present value of lease payments. The asset will be based on the liability, subject to adjustment, such as for initial direct costs. For income statement purposes, Topic 842 retains a dual model, requiring leases to be classified as either operating or finance. Operating leases will result in straight-line expense, while finance leases will result in a front-loaded expense pattern, similar to current capital leases. Classification of operating and finance leases will be based on criteria that are largely similar to those applied in current lease guidance, but without the explicit thresholds. The new guidance is effective for fiscal years beginning after December 15, 2018. The new guidance must be adopted using a modified retrospective transition, and provides for certain practical expedients. Transition will require application of the new guidance at the beginning of the earliest comparative period presented. The Company has started evaluating its current lease contracts. The Company has not determined the amount of impact on its Consolidated Financial Statements, but it anticipates an increase in the recognition of right-of-use assets and lease liabilities.

Investments. In March 2016, the FASB issued ASU 2016-07, "Investments-Equity Method and Joint Ventures; Simplifying the Transition to the Equity Method of Accounting (Topic 323)." The amendments in ASU 2016-07 eliminate the requirement to retroactively adopt the equity method of accounting for a qualifying equity method investment. ASU 2016-07 requires equity method investors to add the cost of acquiring the additional interest in the investee to the current basis of the investor's previously held interest and adopt the equity method of accounting as of the date the investment becomes qualified for equity method accounting. The amendments in this ASU are effective for the fiscal years and interim periods within those fiscal years, beginning after December 15, 2016. The Company does not believe this ASU will have any effect on its Consolidated Financial Statements.

Employee Share Based Payment Accounting. In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share Based Payment Accounting," which amends ASC Topic 718, Compensation - Stock Compensation. ASU 2016-09 includes provisions intended to simplify various aspects related to how share based payments are accounted for and presented in the financial statements. The new guidance among other requirements will require all of the tax effects related to share based payments at settlement (or expiration) to be recorded through the income statement. Currently, tax benefits in excess of compensation cost ("windfalls") are recorded in equity, and tax deficiencies ("shortfalls") are recorded in equity to the extent of previous windfalls, and then to the income statement. This change is required to be applied prospectively to all excess tax benefits and tax deficiencies resulting from settlements after the date of adoption of the ASU 2016-09. Under the new guidance, the windfall tax benefit will be recorded when it arises, subject to normal valuation allowance considerations. This change is required to be applied on a modified retrospective basis, with a cumulative effect adjustment to opening retained earnings. All tax related cash flows resulting from share based payments are to be reported as operating activities on the statement of cash flows, a change from the current requirement to present windfall tax benefits as an inflow from financing activities and an outflow from operating activities. Either prospective or retrospective transition of this provision is permitted. ASU 2016-09 is effective for annual reporting periods beginning after December 15, 2016, and interim periods within that reporting period. The Company will prospectively adopt this standard in the first quarter of 2017 and expects a cumulative effect of approximately $24.8 million to be recorded as a deferred tax asset with the offset in retained earnings. Going forward, tax benefits in excess of compensation cost previously recorded in equity will be recorded within the income statement and all tax related cash flows resulting from share based payments will be recorded as an operating activity within the statement of cash flows.

Financial Instruments-Credit Losses. In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments-Credit Losses: Measurement of Credit Losses on Financial Instruments." The amendment in this update requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions, and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Company does not believe this ASU will have any effect on its Consolidated Financial Statements.

Simplifying the Presentation of Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03, "Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs." The amendments in ASU 2015-03 require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability consistent with debt discounts. The Company adopted this standard and adjusted the December 31, 2015 Consolidated Balance Sheet for the reclassification of debt issuance costs from Total Deferred Charges and Other Assets to Long-Term Debt to be consistent with the December 31, 2016 presentation.

Classification of Certain Cash Receipts and Cash Payments. In August 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments." This standard addresses the classification of seven specific types of cash flows as follows: debt prepayment or extinguishment costs, payments for the extinguishment of zero coupon debt, payments to settle contingent consideration liabilities incurred in a business combination, proceeds from insurance claims, payments to purchase and proceeds from the settlement of company-owned life insurance, distributions from equity method investees, and cash flows related to beneficial interests retained in securitization transactions. In addition to these seven specific issues, the ASU also provides additional guidance on the application of the predominance principle when cash receipts and payments have aspects of more than one class of cash flows. The standard is effective for financial statements issued for fiscal years beginning after December 15, 2017, and interim periods within those fiscal years and retrospective application is required. The Company does not believe this ASU will have a material effect on its Statements of Cash Flows.

Going Concern. In August 2014, the FASB defined management's responsibility to evaluate whether substantial doubt exists about an entity's ability to continue as a going concern. Professional auditing standards require auditors to evaluate the going concern presumption, but previously there was a lack of guidance in GAAP for financial statement preparers. ASU 2014-15, "Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern," requires management to perform a going concern evaluation effective for annual periods ending after December 15, 2016, and annual and interim periods thereafter. The Company adopted this standard in 2016 and management does not believe there is substantial doubt about the entity's ability to continue as a going concern.

Fair Value Measurement. In May 2015, the FASB issued ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent." ASU 2015-07 removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient and eliminates certain disclosures for those investments. The Company adopted this standard in 2016 which minimally impacted disclosures within the Retirement Plans and Postretirement Benefit Plans footnote included in this filing.

3. Investment in Unconsolidated Affiliate and Related Party Transactions

On March 14, 2013, the Company entered into a Master Formation Agreement with the ArcLight group and CenterPoint pursuant to which the Company, the ArcLight group and CenterPoint, agreed to form Enable to own and operate the midstream businesses of the Company and CenterPoint that was initially structured as a private limited partnership. This transaction closed on May 1, 2013.

Pursuant to the Master Formation Agreement, the Company and the ArcLight group indirectly contributed 100 percent of the equity interests in Enogex LLC to Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost.

The general partner of Enable is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company deconsolidated its interest in Enogex Holdings and began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25.0 million common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2016, the Company owned 111.0 million common units, or 25.7 percent, of Enable's outstanding common units. Of the Company's 111.0 million common units, 68.2 million units were subordinated. The subordination period began on the closing date of Enable's initial public offering and will extend until the first business day following the distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017. The Company anticipates that the subordination period will expire in August 2017 and will not impact future distributions that the Company receives from Enable.

On February 10, 2017, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common and subordinated units, which is unchanged from the previous quarter. If cash distributions to Enable's unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. The Company is entitled to 60 percent of those "incentive distributions." In certain circumstances, the general partner has the right to reset the minimum quarterly distribution and the target distribution levels at which the incentive distributions receive increasing percentages to higher levels based on Enable's cash distributions at the time of the exercise of this reset election.

Distributions received from Enable were $141.2 million, $139.3 million and $143.7 million during the years ended December 31, 2016, 2015 and 2014, respectively.

In 2016, CenterPoint announced that it was evaluating strategic alternatives for its investment in Enable. On July 18, 2016, CenterPoint and its wholly owned subsidiary, CenterPoint Energy Resources Corp., provided notice to the Company of

CenterPoint’s solicitation of offers from unrelated third parties to acquire all or any portion of the common units and subordinated units of Enable owned by CenterPoint Energy Resources Corp. and all of the membership interests of the general partner of Enable owned by CenterPoint Energy Resources Corp. This notice also constituted a notice pursuant to the right of first offer held by the Company under the Partnership Agreement and the Third Amended and Restated Limited Liability Company Agreement of the general partner. Under the terms of the right of first offer, the Company has 30 days from receipt of a notice from CenterPoint to make an offer to buy all of CenterPoint’s membership interests in the general partner and all or any portion of CenterPoint Energy Resources Corp.'s common units and subordinated units. On August 17, 2016, the Company submitted to CenterPoint a proposal to acquire, in conjunction with a third party, all of CenterPoint's membership interests in Enable GP and all of the common units and subordinated units of Enable owned by CenterPoint. In accordance with the Enable partnership Agreement, CenterPoint had 30 days after the proposal was submitted to accept the Company's right of first offer proposal. As of September 17, 2016, CenterPoint had not accepted the Company's proposal, thereby rejecting it.

On January 16, 2017, CenterPoint and its wholly owned subsidiary, CenterPoint Energy Resources Corp., provided a second notice to the Company of CenterPoint's solicitation of offers from unrelated third parties to acquire all or any portion of the common units and subordinated units of Enable owned by CenterPoint Energy Resources Corp. and all of the membership interests of the general partner of Enable owned by CenterPoint Energy Resources Corp. On February 15, 2017, under the terms of right of first offer, the Company submitted to CenterPoint another proposal to acquire, in conjunction with a third party, all of CenterPoint's membership interests in Enable GP and all of the common units and subordinated units of Enable owned by CenterPoint. If the Company's proposal is accepted by CenterPoint, and if the transaction contemplated by the proposal is in fact consummated, the Company anticipates that the third party would, as a result of such transaction, become the owner of all or substantially all of the securities subject to the right of first offer. The Company's ownership interest in Enable would not materially change as a result of such transaction, and therefore the Company would not be required to consolidate the financial results of Enable with the financial results of the Company.

The Company cannot predict what action CenterPoint will take in response to the proposal, if any, and there can be no assurance that any transaction will result from the Company's proposal or that any party will enter into a definitive agreement regarding a potential transaction, including the above-referenced third party. The Company's proposal is subject to a number of customary conditions.

Related Party Transactions

Operating costs charged and related party transactions between the Company and its affiliate, Enable, are discussed below.

In connection with the formation of Enable, the Company and Enable entered into a Services Agreement, Employee Transition Agreement, and other agreements whereby the Company agreed to provide certain support services to Enable such as accounting, legal, risk management and treasury functions for an initial term ending on April 30, 2016. As of December 31, 2015, Enable terminated all support services except certain information technology, payroll and benefits administration. The remaining services automatically extended for another year on May 1, 2016. Under these agreements, the Company charged operating costs to Enable of $4.7 million, $12.4 million and $16.8 million for December 31, 2016, 2015 and 2014, respectively. The Company charges operating costs to OG&E and Enable based on several factors. Operating costs directly related to OG&E and Enable are assigned as such. Operating costs incurred for the benefit of OG&E and Enable are allocated either as overhead based primarily on labor costs or using the "Distrigas" method.

The Company agreed to provide seconded employees to Enable to support its operations for an initial term ending on December 31, 2014. In October 2014, CenterPoint, the Company and Enable agreed to continue the secondment to Enable for 192 employees that participate in the Company's defined benefit and retirement plans. The Company billed Enable for reimbursement of $28.6 million, $32.7 million and $104.8 million in 2016, 2015 and 2014, respectively, under the Transitional Seconding Agreement for employment costs. If the seconding agreement was terminated, and those employees were no longer employed by the Company, and lump sum payments were made to those employees, the Company would recognize a settlement or curtailment of the pension/retiree health care charges, which would increase expense at the Company by approximately $21.4 million. Settlement and curtailment charges associated with the Enable seconded employees are not reimbursable to the Company by Enable. The seconding agreement can be terminated by mutual agreement of the Company and Enable or solely by the Company upon 120 day notice.

The Company had accounts receivable from Enable of $2.7 million and $3.4 million as of December 31, 2016 and 2015, respectively, for amounts billed for transitional services, including the cost of seconded employees.

Related Party Transactions with Enable

OG&E entered into a contract with Enable to provide transportation services effective May 1, 2014. This transportation agreement grants Enable the responsibility of delivering natural gas to OG&E's generating facilities and performing an imbalance service. With this imbalance service, in accordance with the cash-out provision of the contract, OG&E purchases gas from Enable when Enable's deliveries exceed OG&E's pipeline receipts. Enable purchases gas from OG&E when OG&E's pipeline receipts exceed Enable's deliveries. In 2016, OG&E entered into an additional gas transportation services contract with Enable which will be effective upon the conversion of units 4 and 5 at Muskogee from coal to gas. The following table summarizes related party transactions between OG&E and Enable during the years ended December 31, 2016, 2015 and 2014.

	Year Ended December 31,		
(In millions)	**2016**	2015	2014
Operating Revenues:			
Electricity to power electric compression assets	**$ 11.5**	$ 13.8	$ 13.3
Cost of Sales:			
Natural gas transportation services	**$ 35.0**	$ 35.0	$ 34.9
Natural gas storage services	**—**	—	4.4
Natural gas purchases/(sales)	**11.2**	7.6	8.7

Summarized Financial Information of Enable

Summarized unaudited financial information for 100 percent of Enable is presented below as of December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014.

Balance Sheet	December 31,	
(In millions)	**2016**	2015
Current assets	**$ 396**	$ 381
Non-current assets	**10,816**	10,845
Current liabilities	**362**	615
Non-current liabilities	**3,056**	3,080

Income Statement	Year Ended December 31,		
(In millions)	**2016**	2015	2014
Operating revenues	**$ 2,272**	$ 2,418	$ 3,367
Cost of natural gas and natural gas liquids	**1,017**	1,097	1,914
Operating income (loss)	**385**	(712)	586
Net income (loss)	**290**	(752)	530

The formation of Enable was considered a business combination, and CenterPoint was the acquirer of Enogex Holdings for accounting purposes. Under this method, the fair value of the consideration paid by CenterPoint for Enogex Holdings is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their fair value. Enogex Holdings' assets, liabilities and equity have accordingly been adjusted to estimated fair value as of May 1, 2013, resulting in an increase to Enable's equity of $2.2 billion. Due to the contribution of Enogex LLC to Enable meeting the requirements of being in substance real estate and thus recording the initial investment at historical cost, the effects of the amortization and depreciation expense associated with the fair value adjustments on Enable's results of operations have been eliminated in the Company's recording of its equity in earnings of Enable.

The Company recorded equity in earnings of unconsolidated affiliates of $101.8 million, $15.5 million and $172.6 million for the years ended December 31, 2016, 2015 and 2014, respectively. Equity in earnings of unconsolidated affiliates includes the Company's share of Enable earnings adjusted for the amortization of the basis difference of the Company's investment in Enogex and its underlying equity in the net assets of Enable and is also adjusted for the elimination of the Enogex Holdings fair value adjustments. The basis difference is being amortized over approximately 30 years, the average life of the assets to which the basis difference is attributed. Equity in earnings of unconsolidated affiliates is also adjusted for the elimination of the Enogex Holdings fair value adjustments, as described below.

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2016 and 2015.

	Year Ended December 31,	
Reconciliation of Equity in Earnings (Loss) of Unconsolidated Affiliates	**2016**	2015
(In millions)		
Enable net income (loss)	**$ 289.5**	$ (752.0)
Distributions senior to limited partners	**(9.1)**	—
Differences due to timing of OGE Energy and Enable accounting close	**(12.1)**	12.1
Enable net income (loss) used to calculate OGE Energy's equity in earnings	**$ 268.3**	$ (739.9)
OGE Energy’s percent ownership at year end	**25.7%**	26.3%
OGE Energy’s portion of Enable net income (loss)	**$ 70.7**	$ (194.4)
Impairments recognized by Enable associated with OGE Energy’s basis differences	**2.6**	178.4
OGE Energy's share of Enable net income (loss)	**73.3**	(16.0)
Amortization of basis difference	**11.6**	13.5
Elimination of Enable fair value step up	**16.9**	18.0
Equity in earnings of unconsolidated affiliates	**$ 101.8**	$ 15.5

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $743.7 million as of December 31, 2016. The basis difference is being amortized over approximately 30 years, beginning in May 2013. The following table reconciles the basis difference in Enable from December 31, 2015 to December 31, 2016.

(In millions)	
Basis difference as of December 31, 2015	$ 783.5
Dilution and impairments associated with OGE Energy’s basis difference	(11.3)
Amortization of basis difference	(11.6)
Elimination of Enable fair value step up	(16.9)
Basis difference as of December 31, 2016	$ 743.7

2015 Goodwill Impairment. Enable tested its goodwill for impairment annually on October 1, or more frequently if events or changes in circumstances indicated that the carrying value of goodwill may not be recoverable. Goodwill was assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. Subsequent to the completion of the October 1, 2014 annual test, the crude oil and natural gas industry was impacted by further commodity price declines, which consequently resulted in decreased producer activity in certain regions in which Enable operates. Based on the decline in producer activity and the forecasted impact on future periods, in addition to an increase in the weighted average cost of capital, Enable determined that the impact on its forecasted operating profits and cash flows for its gathering and processing and transportation and storage segments for the next five years would be significantly reduced. As a result, when Enable performed the first step of its annual goodwill impairment analysis as of October 1, 2015, it determined that the carrying value of the gathering and processing and transportation and storage segments exceeded fair value. Enable completed the second step of the goodwill impairment analysis comparing the implied fair value for those reporting units to the carrying amount of that goodwill and determined that goodwill for those units was completely impaired in the amount of $1.086 billion as of September 30, 2015, and wrote off all of its goodwill in the third quarter of 2015.

Accordingly, the Company recorded a $108.4 million pre-tax charge in the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis differences.

4. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data is observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

The Company had no financial instruments measured at fair value on a recurring basis at December 31, 2016 and 2015. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy with the exception of the Tinker Debt whose fair value is based on calculating the net present value of the monthly payments discounted by the Company's current borrowing rate and is classified as Level 3 in the fair value hierarchy. The following table summarizes the fair value and carrying amount of the Company's financial instruments at December 31, 2016 and 2015.

	2016		2015	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt (including Long-Term Debt due within one year)				
Senior Notes	**$ 2,385.5**	**$ 2,657.2**	$ 2,493.9	$ 2,754.6
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Tinker Debt	**9.9**	**11.3**	10.0	9.2
OGE Energy Senior Notes	**99.7**	**99.9**	99.5	99.9

5. Stock-Based Compensation

In 2013, the Company adopted, and its shareholders approved, the Stock Incentive Plan. Under the Stock Incentive Plan, restricted stock, restricted stock units, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 7,400,000 shares under the Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2016, 2015 and 2014 related to the Company's performance units and restricted stock.

Year ended December 31 *(In millions)*	**2016**	2015	2014
Performance units			
Total shareholder return	**$ 4.5**	$ 7.6	$ 8.3
Earnings per share	**—**	0.7	3.7
Total performance units	**4.5**	8.3	12.0
Restricted stock	**0.1**	0.1	—
Total compensation expense	**4.6**	8.4	12.0
Less: Amount paid by unconsolidated affiliates	**—**	0.5	3.6
Net compensation expense	**$ 4.6**	$ 7.9	$ 8.4
Income tax benefit	**$ 1.8**	$ 3.1	$ 3.3

The Company has issued new shares to satisfy restricted stock grants and payouts of earned performance units. In 2016, 2015 and 2014, there were 2,100 shares, 82,046 shares and 494,637 shares, respectively, of new common stock issued pursuant to the Company's Stock Incentive Plan related to restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2016, there were 901 shares of restricted stock returned to the Company to satisfy tax liabilities.

Performance Units

Under the Stock Incentive Plan, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the primarily three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a primarily three-year award cycle (i.e., three-year cliff vesting period) is dependent on the Company's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share growth over a primarily three-year award cycle (i.e., three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of these performance units are classified as equity in the Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the primarily three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends were not accrued or paid for awards prior to February 2014, and were therefore not included in the fair value calculation. Beginning with the February 2014 performance unit awards, dividends are accrued on a quarterly basis pending achievement of payout criteria, and were therefore included in the fair value calculations. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2016	2015	2014
Number of units granted	**284,211**	264,454	219,106
Fair value of units granted	**$ 20.97**	$ 31.02	$ 34.80
Expected dividend yield	**3.5%**	2.6%	2.5%
Expected price volatility	**19.8%**	16.9%	20.0%
Risk-free interest rate	**0.88%**	0.91%	0.67%
Expected life of units (in years)	**2.84**	2.85	2.86

Performance Units – Earnings Per Share

The fair value of the performance units based on earnings per share is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on earnings per share varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2016	2015	2014
Number of units granted	**94,735**	88,156	73,037
Fair value of units granted	**$ 26.64**	$ 33.99	$ 34.81

Restricted Stock

Under the Stock Incentive Plan, the Company issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a primarily three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period on restricted stock granted prior to July 2014, and therefore dividends are included in the fair value calculation for such restricted stock granted prior to July 2014.

For restricted stock granted after July 2014, dividends will only be paid on restricted stock awards that vest. Accordingly, for restricted stock granted after July 2014, only the present value of dividends expected to vest are included in the fair value calculations. The expected life of the restricted stock is based on the non-vested period since inception of the primarily three-year award cycle. There are no post-vesting restrictions related to the Company's restricted stock. The number of shares of restricted stock granted and the grant date fair value are shown in the following table.

	2016	2015	2014
Shares of restricted stock granted	**1,881**	958	7,037
Fair value of restricted stock granted	**$ 29.27**	$ 26.11	$ 35.71

A summary of the activity for the Company's performance units and restricted stock at December 31, 2016 and changes in 2016 are shown in the following table.

	Performance Units				Restricted Stock	
	Total Shareholder Return		Earnings Per Share			
(Dollars in millions)	Number of Units	Aggregate Intrinsic Value	Number of Units	Aggregate Intrinsic Value	Number of Shares	Aggregate Intrinsic Value
Units/Shares Outstanding at 12/31/15	724,058		241,470		7,623	
Granted	**284,211 (A)**		**94,735 (A)**		**1,881**	
Converted	**(327,988) (B)**	**$ —**	**(109,445) (B)**	**$ —**	**N/A**	
Vested	**N/A**		**N/A**		**(4,324)**	**$ 0.1**
Forfeited	**(16,236)**		**(5,410)**		**(268)**	
Units/Shares Outstanding at 12/31/16	**664,045**	**$ 17.3**	**221,350**	**$ 1.9**	**4,912**	**$ 0.2**
Units/Shares Fully Vested at 12/31/16	**185,214**	**$ —**	**61,742**	**$ —**		

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from zero percent to 200 percent of the target.

(B) These amounts represent performance units that vested at December 31, 2015 which were settled in February 2016.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2016 and changes in 2016 are shown in the following table.

	Performance Units				Restricted Stock	
	Total Shareholder Return		Earnings Per Share			
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/Shares Non-Vested at 12/31/15	396,943	$ 32.83	132,316	$ 34.30	7,623	$ 29.68
Granted	**284,211 (A)**	**$ 20.97**	**94,735 (A)**	**$ 26.64**	**1,881**	**$ 29.27**
Converted	**(873) (B)**	**$ 33.01**	**(291) (B)**	**$ 33.01**	**N/A**	**N/A**
Vested	**(185,214)**	**$ 34.82**	**(61,742)**	**$ 34.83**	**(4,324)**	**$ 32.98**
Forfeited	**(16,236)**	**$ 28.89**	**(5,410)**	**$ 31.95**	**(268)**	**$ 37.31**
Units/Shares Non-Vested at 12/31/16	**478,831**	**$ 25.16**	**159,608**	**$ 29.71**	**4,912**	**$ 31.29**
Units/Shares Expected to Vest	**476,920 (C)**		**158,975 (C)**		**4,912**	

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from zero percent to 200 percent of the target.

(B) Units paid out under terms of plan due to the death of a participant.

(C) The intrinsic value of the performance units based on total shareholder return and earnings per share is $15.3 million and $5.1 million, respectively.

Fair Value of Vested Performance Units and Restricted Stock

A summary of the Company's fair value for its vested performance units and restricted stock is shown in the following table.

Year ended December 31 *(In millions)*	**2016**	2015	2014
Performance units			
Total shareholder return	**$ 6.4**	$ 8.5	$ 9.5
Earnings per share	**—**	—	3.8
Restricted stock	**0.1**	0.2	0.2

Unrecognized Compensation Cost

A summary of the Company's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

December 31, 2016	Unrecognized Compensation Cost *(in millions)*	Weighted Average to be Recognized *(in years)*
Performance units		
Total shareholder return	**$ 5.8**	**1.59**
Earnings per share	**2.3**	**1.63**
Total performance units	**8.1**	
Restricted stock	**0.1**	**1.55**
Total	**$ 8.2**	

6. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affected recognized assets and liabilities but did not result in cash receipts or payments. Also disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year ended December 31 *(In millions)*	**2016**	2015	2014
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 39.5**	$ 2.3	$ —
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid during the period for			
Interest (net of interest capitalized) (A)	**$ 141.9**	$ 145.4	$ 150.8
Income taxes (net of income tax refunds)	**(5.9)**	(3.4)	0.2

(A) Net of interest capitalized of $7.5 million, $4.2 million and $2.4 million in 2016, 2015 and 2014, respectively.

7. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2016**	2015	2014
Provision (Benefit) for Current Income Taxes			
Federal	**$ —**	$ —	$ —
State	**(5.7)**	(5.2)	(4.5)
Total Provision (Benefit) for Current Income Taxes	**(5.7)**	(5.2)	(4.5)
Provision for Deferred Income Taxes, net			
Federal	**126.0**	98.8	160.0
State	**28.0**	4.5	18.2
Total Provision for Deferred Income Taxes, net	**154.0**	103.3	178.2
Deferred Federal Investment Tax Credits, net	**(0.2)**	(0.7)	(0.9)
Total Income Tax Expense	**$ 148.1**	$ 97.4	$ 172.8

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2013 or state and local tax examinations by tax authorities for years prior to 2012. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E earns both Federal and Oklahoma state tax credits associated with production from its wind farms and earns Oklahoma state tax credits associated with its investments in electric generating facilities which reduce the Company's effective tax rate.

The following schedule reconciles the statutory tax rates to the effective income tax rate:

Year ended December 31	**2016**	2015	2014
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
Federal renewable energy credit (A)	**(6.8)**	(8.9)	(6.7)
Remeasurement of state deferred tax liabilities	**0.9**	(0.8)	0.4
401(k) dividends	**(0.6)**	(0.7)	(0.5)
Federal investment tax credits, net	**(0.8)**	(0.2)	(0.2)
State income taxes, net of Federal income tax benefit	**1.9**	0.1	1.2
Uncertain tax positions	**0.1**	0.7	0.5
Amortization of net unfunded deferred taxes	**0.7**	0.9	0.6
Other	**0.1**	0.3	0.1
Effective income tax rate	**30.5 %**	26.4 %	30.4 %

(A) Represents credits associated with the production from OG&E's wind farms.

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2016 and 2015, respectively, were as follows:

December 31 (In millions)		**2016**		2015
Non-Current Deferred Income Tax Liabilities, net				
Accelerated depreciation and other property related differences	**$**	**2,103.2**	$	2,016.0
Investment in Enable Midstream Partners		**657.3**		623.4
Regulatory asset		**34.4**		32.7
Income taxes refundable to customers, net		**24.1**		22.0
Company Pension Plan		**16.5**		13.7
Bond redemption-unamortized costs		**4.3**		4.8
Derivative instruments		**2.2**		1.5
Federal tax credits		**(220.6)**		(184.4)
State tax credits		**(112.2)**		(106.7)
Postretirement medical and life insurance benefits		**(48.9)**		(56.2)
Regulatory liabilities		**(34.6)**		(46.3)
Net operating losses		**(31.7)**		(94.6)
Asset retirement obligations		**(24.5)**		(22.5)
Accrued liabilities		**(16.1)**		(14.0)
Other		**(14.0)**		(6.6)
Accrued vacation		**(3.5)**		(3.2)
Deferred Federal investment tax credits		**(0.8)**		(0.9)
Uncollectible accounts		**(0.6)**		(0.5)
Non-Current Deferred Income Tax Liabilities, net	**$**	**2,334.5**	$	2,178.2

As of December 31, 2016, the Company has classified $13.7 million of unrecognized tax benefits as a reduction of deferred tax assets recorded. Management is currently unaware of any issues under review that could result in significant additional payments, accruals, or other material deviation from this amount.

Following is a reconciliation of the Company’s total gross unrecognized tax benefits as of the years ended December 31, 2016, 2015, and 2014.

(In millions)		**2016**		2015		2014
Balance at January 1	**$**	**20.2**	$	16.1	$	12.0
Tax positions related to current year:						
Additions		**0.5**		4.1		4.1
Balance at December 31	**$**	**20.7**	$	20.2	$	16.1

As of December 31, 2016, 2015 and 2014, there are $13.5 million, $13.2 million and $10.5 million of unrecognized tax benefits that if recognized would affect the annual effective tax rate.

OG&E has determined that a portion of certain Oklahoma investment tax credits previously recognized but not yet utilized may not be available for utilization in future years. During 2016, OG&E recorded an additional reserve for this item of $0.5 million ($0.3 million after the federal tax benefit) related to the same Oklahoma investment tax credits generated in the current year but not yet utilized due to management's determination that it is more likely than not that it will be unable to utilize these credits.

Where applicable, the Company classifies income tax-related interest and penalties as interest expense and other expense, respectively. During the year ended December 31, 2016, there were no income tax-related interest or penalties recorded with regard to uncertain tax positions.

Other

The Company sustained Federal and state tax operating losses through 2012 caused primarily by bonus depreciation and other book versus tax temporary differences. As a result, the Company had accrued Federal and state income tax benefits carrying into 2016. As the Company can no longer carry these losses back to prior periods, these losses are being carried forward for utilization in future years which began in 2013. In addition to the tax operating losses, the Company was unable to utilize the various tax credits that were generated during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. Under current law, the Company anticipates future taxable income will be sufficient to utilize all of the losses and remaining credits before they begin to expire. The following table summarizes these carry forwards:

(In millions)	Carry Forward Amount	Deferred Tax Asset	Earliest Expiration Date
Net operating losses			
State operating loss	$ 554.7	$ 20.4	2030
Federal operating loss	32.2	11.3	2030
Federal tax credits	220.6	220.6	2029
State tax credits			
Oklahoma investment tax credits	135.7	88.2	N/A
Oklahoma capital investment board credits	7.3	7.3	N/A
Oklahoma zero emission tax credits	24.1	16.2	2020
Louisiana inventory credits	0.7	0.5	2019

The Company has generated excess tax benefits of $24.8 million related to its equity based compensation plan which have not been recognized during the time it has been in a net operating loss position. This balance is available to offset future taxable income in addition to the net operating loss balances presented above. The Company anticipates adoption of ASU 2016-09 during 2017 which will result in the value of these excess tax benefits being recorded as a deferred tax asset with an offset to retained earnings.

8. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued no shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2016. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan or purchase shares traded on the open market. At December 31, 2016, there were 4,774,442 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

Basic earnings per share is calculated by dividing net income by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units and restricted stock. Basic and diluted earnings per share for the Company were calculated as follows:

(In millions except per share data)	**2016**	2015	2014
Net income	**$ 338.2**	$ 271.3	$ 395.8
Average Common Shares Outstanding			
Basic average common shares outstanding	**199.7**	199.6	199.2
Effect of dilutive securities:			
Contingently issuable shares (performance and restricted stock units)	**0.2**	—	0.7
Diluted average common shares outstanding	**199.9**	199.6	199.9
Basic Earnings Per Average Common Share	**$ 1.69**	$ 1.36	$ 1.99
Diluted Earnings Per Average Common Share	**$ 1.69**	$ 1.36	$ 1.98
Anti-dilutive shares excluded from earnings per share calculation	**—**	—	—

Dividend Restrictions

The Company’s Certificate of Incorporation places restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. As there is no preferred stock outstanding, that restriction did not place any effective limit on the Company’s ability to pay dividends to its shareholders. Pursuant to the leverage restriction in the Company’s revolving credit agreement, the Company must maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately$452.8 million of the Company’s retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of the Company’s retained earnings as of December 31, 2016 are unrestricted for the payment of dividends.

The Company utilizes receipts from its equity investment in Enable and dividends from OG&E to pay dividends to its shareholders. Enable’s partnership agreement requires that it distribute all "available cash," as defined as cash on hand at the end of a quarter after the payment of expenses and the establishment of cash reserves, and cash on hand resulting from working capital borrowings made after the end of the quarter. Pursuant to the Federal Power Act, OG&E is restricted from paying dividends from its capital accounts. Dividends are paid from retained earnings. Pursuant to the leverage restriction in OG&E’s revolving credit agreement, OG&E must also maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $351.5 million of OG&E’s retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of OG&E’s retained earnings as of December 31, 2016 are unrestricted for the payment of dividends.

9. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2016, the Company was in compliance with all of its debt agreements.

OG&E Industrial Authority Bonds

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds on any business day. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES			DATE DUE	AMOUNT
				(In millions)
0.05%	-	0.90%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.07%	-	0.83%	Muskogee Industrial Authority, January 1, 2025	32.4
0.05%	-	0.86%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)				$ 135.4

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such bonds, OG&E is obligated to repurchase such unremarketed bonds. As OG&E has both the intent and ability to refinance the bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the bonds are classified as Long-Term Debt in the Company's Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $225.2 million, $250.1 million, $250.1 million, $0.1 million and $0.1 million in years 2017, 2018, 2019, 2020 and 2021, respectively.

The Company has previously incurred costs related to debt refinancing. Unamortized loss on reacquired debt is classified as a Non-Current Regulatory Asset, unamortized debt expense and unamortized premium and discount on long-term debt is classified as Long-Term Debt in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

10. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. As of December 31, 2016, the Company had $236.2 million in short-term debt compared to no balance at December 31, 2015. The following table provides information regarding the Company's revolving credit agreements at December 31, 2016.

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Expiration	
	(In millions)				
OGE Energy (B)	$ 750.0	$ 236.2	0.95% (D)	December 13, 2018	(E)
OG&E (C)	400.0	1.8	0.95% (D)	December 13, 2018	(E)
Total	$ 1,150.0	$ 238.0	0.95%		

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2016.
(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.
(E) In December 2011, OGE Energy and OG&E entered into unsecured revolving credit agreements in the aggregate of $1,150.0 million ($750.0 million for OGE Energy and $400.0 million for OG&E) which expire in December 2018. OGE Energy and OG&E expect to replace the existing agreements with new revolving credit agreements during 2017, under terms and conditions generally similar to the existing agreements.

The Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2017 and ending December 31, 2018.

11. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2016, the Company made a $20.0 million contribution to its Pension Plan. During 2015, the Company did not make any contributions to its Pension Plan. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2017. Any contribution to the Pension Plan during 2017 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended. The Company could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization’s net periodic pension cost. During the quarter ended June 30, 2016, the Company experienced a settlement of its Supplemental

Executive Retirement Plan and its non-qualified Restoration of Retirement Income Plan. As a result, the Company recorded pension settlement charges of $8.6 million during 2016. During 2015, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments paid to such employees upon retirement. As a result, the Company recorded pension settlement charges of $16.2 million in the third quarter of 2015 and $5.5 million in the fourth quarter of 2015. The pension settlement charges did not increase the Company's total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods.

The Company provides a Restoration of Retirement Income Plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations of the Code. Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans for 2016 and 2015. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheets. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods. The benefit obligation for the Company's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2016 was $608.0 million and $6.1 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2015 was $610.9 million and $24.6 million, respectively. The details of the funded status of the Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2016**	2015	**2016**	2015	**2016**	2015
Change in Benefit Obligation						
Beginning obligations	**$ 680.0**	$ 725.0	**$ 25.1**	$ 19.7	**$ 225.3**	$ 280.9
Service cost	**15.8**	16.1	**0.3**	1.3	**0.8**	1.5
Interest cost	**25.5**	26.1	**0.4**	0.7	**9.5**	10.3
Plan settlements	**—**	(60.7)	**(20.6)**	—	**—**	—
Participants' contributions	**—**	—	**—**	—	**3.6**	3.4
Actuarial (gains) losses	**4.7**	(11.3)	**1.8**	4.0	**(7.6)**	(55.1)
Benefits paid	**(53.8)**	(15.2)	**—**	(0.6)	**(15.7)**	(15.7)
Ending obligations	**$ 672.2**	$ 680.0	**$ 7.0**	$ 25.1	**$ 215.9**	$ 225.3
Change in Plans' Assets						
Beginning fair value	**$ 581.7**	$ 679.8	**$ —**	$ —	**$ 55.3**	$ 59.6
Actual return on plans' assets	**48.0**	(22.2)	**—**	—	**2.0**	(0.5)
Employer contributions	**20.0**	—	**20.6**	0.6	**7.9**	8.5
Plan settlements	**—**	(60.7)	**(20.6)**	—	**—**	—
Participants' contributions	**—**	—	**—**	—	**3.6**	3.4
Benefits paid	**(53.8)**	(15.2)	**—**	(0.6)	**(15.7)**	(15.7)
Ending fair value	**$ 595.9**	$ 581.7	**$ —**	$ —	**$ 53.1**	$ 55.3
Funded status at end of year	**$ (76.3)**	**$ (98.3)**	**$ (7.0)**	**$ (25.1)**	**$ (162.8)**	**$ (170.0)**

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31 *(In millions)*	**2016**	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Service cost	**$ 15.8**	$ 16.1	$ 15.3	**$ 0.3**	$ 1.3	$ 1.1	**$ 0.8**	$ 1.5	$ 3.1
Interest cost	**25.5**	26.1	28.1	**0.4**	0.7	0.6	**9.5**	10.3	11.4
Expected return on plan assets	**(41.5)**	(46.0)	(45.3)	**—**	—	—	**(2.3)**	(2.4)	(2.4)
Amortization of net loss	**16.5**	18.0	14.3	**0.7**	0.6	0.2	**2.6**	13.9	12.3
Amortization of unrecognized prior service cost (A)	**(0.1)**	0.4	1.7	**0.1**	0.1	0.2	**(8.8)**	(16.5)	(16.5)
Curtailment	**—**	—	(0.2)	**—**	—	—	**—**	—	—
Settlement	**—**	21.7	—	**8.6**	—	—	**—**	—	—
Total net periodic benefit cost	**16.2**	36.3	13.9	**10.1**	2.7	2.1	**1.8**	6.8	7.9
Less: Amount paid by unconsolidated affiliates	**5.1**	4.2	3.2	**0.3**	0.1	0.1	**0.2**	1.3	1.3
Net periodic benefit cost (B)	**$ 11.1**	$ 32.1	$ 10.7	**$ 9.8**	$ 2.6	$ 2.0	**$ 1.6**	$ 5.5	$ 6.6

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $22.5 million, $40.2 million and $19.3 million of net periodic benefit cost recognized in 2016, 2015 and 2014, respectively, OG&E recognized the following:

- a change in pension expense in 2016, 2015 and 2014 of $9.9 million, $(3.1) million and $11.2 million, respectively, to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction, which are included in the Pension tracker regulatory asset or liability (see Note 1);
- an increase in postretirement medical expense in 2016, 2015 and 2014 of $7.9 million, $5.8 million and $5.2 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory asset or liability (see Note 1); and
- a deferral of pension expense in 2016 and 2015 of $0.1 million and $1.9 million related to the Arkansas jurisdictional portion of the pension settlement charge of $8.6 million and $21.7 million, respectively.

(In millions)	**2016**	2015	2014
Capitalized portion of net periodic pension benefit cost	**$ 4.0**	$ 5.0	$ 3.4
Capitalized portion of net periodic postretirement benefit cost	**0.8**	1.9	2.0

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2016**	2015	2014	**2016**	2015	2014
Discount rate	**4.00%**	4.00%	3.80%	**4.20%**	4.25%	3.80%
Rate of return on plans' assets	**7.50%**	7.50%	7.50%	**4.00%**	4.00%	4.00%
Compensation increases	**4.20%**	4.20%	4.20%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**6.75%**	6.10%	7.85%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.48%
Ultimate trend year	**N/A**	N/A	N/A	**2026**	2026	2028

N/A - not applicable

The overall expected rate of return on plan assets assumption was 7.50 percent in both 2016 and 2015, which was used in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 6.75 percent in 2017 with the rates trending downward to 4.50 percent by 2026. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE			
Year ended December 31 *(In millions)*	**2016**	2015	2014
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$ —
Effect on accumulated postretirement benefit obligations	**0.2**	0.2	0.1

ONE-PERCENTAGE POINT DECREASE			
Year ended December 31 *(In millions)*	**2016**	2015	2014
Effect on aggregate of the service and interest cost components	**$ —**	$ 0.1	$ 0.1
Effect on accumulated postretirement benefit obligations	**0.7**	0.7	0.7

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

Projected Benefit Obligation Funded Status Thresholds	**<90%**	**95%**	**100%**	**105%**	**110%**	**115%**	**120%**
Fixed income	50%	58%	65%	73%	80%	85%	90%
Equity	50%	42%	35%	27%	20%	15%	10%
Total	100%	100%	100%	100%	100%	100%	100%

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

Asset Class	**Target Allocation**	**Minimum**	**Maximum**
Domestic Large Cap Equity	40%	35%	60%
Domestic Mid-Cap Equity	15%	5%	25%
Domestic Small-Cap Equity	25%	5%	30%
International Equity	20%	10%	30%

The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

The portfolio is rebalanced at least on an annual basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the trust is to provide a rate of return consistently from three percent to five percent over the rate of inflation (as measured by the national Consumer Price Index) on a fee adjusted basis over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Active Duration Fixed Income	Bloomberg Barclays Aggregate
Long Duration Fixed Income	Duration blended Barclays Long Government/Credit & Barclays Universal
Equity Index	Standard & Poor's 500 Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital Investment ACWI ex-US

The fixed income managers are expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. A portfolio may invest up to 15 percent of the portfolio's market value in private placement, including 144A securities with or without registration rights and allow for futures to be traded in the portfolio. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap equity manager will purchase shares of companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and an earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International All Country World ex-US Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-US Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the United States. All of the equities which are purchased for the international portfolio are thoroughly researched. All securities are freely traded on a recognized stock exchange and there are no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than five percent can be invested in any one stock at the time of purchase and no more than 10 percent after accounting for price appreciation. Options or financial futures may not be purchased unless prior approval of the Company's Investment Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2016 and 2015. There were no Level 3 investments held by the Pension Plan at December 31, 2016 and 2015.

(In millions)	December 31, 2016	Level 1	Level 2	NAV
Common stocks	$ 237.1	$ 237.1	$ —	$ —
U.S. treasury notes and bonds (A)	122.3	122.3	—	—
Mortgage and asset-backed securities	59.2	—	59.2	—
Corporate fixed income and other securities	137.6	—	137.6	—
Commingled fund (B)	23.8	—	—	23.8
Foreign government bonds	5.2	—	5.2	—
U.S. municipal bonds	1.9	—	1.9	—
Money market fund	2.2	—	—	2.2
Mutual fund	9.0	9.0	—	—
Futures				
U.S. Treasury futures (receivable)	10.7	—	10.7	—
U.S. Treasury futures (payable)	(2.3)	—	(2.3)	—
Cash collateral	0.3	0.3	—	—
Forward contracts				
Receivable (foreign currency)	0.2	—	0.2	—
Total Plan investments	$ 607.2	$ 368.7	$ 212.5	$ 26.0
Receivable from broker for securities sold	—			
Interest and dividends receivable	3.0			
Payable to broker for securities purchased	(14.3)			
Total Plan assets	$ 595.9			

(In millions)	December 31, 2015	Level 1	Level 2	NAV
Common stocks	$ 208.2	$ 208.2	$ —	$ —
U.S. treasury notes and bonds (A)	158.9	158.9	—	—
Mortgage-backed securities	14.5	—	14.5	—
Corporate fixed income and other securities	140.2	—	140.2	—
Commingled fund (B)	24.4	—	—	24.4
Foreign government bonds	5.6	—	5.6	—
U.S. municipal bonds	4.9	—	4.9	—
Interest-bearing cash	0.4	0.4	—	—
Money market fund	11.7	—	—	11.7
Index fund	1.8	1.8	—	—
Mutual fund	24.3	24.3	—	—
Preferred stocks	0.3	0.3	—	—
Futures				
U.S. Treasury futures (receivable)	17.6	—	17.6	—
U.S. Treasury futures (payable)	(12.4)	—	(12.4)	—
Forward contracts				
Receivable (foreign currency)	0.1	—	0.1	—
Payable (foreign currency)	(0.1)	—	(0.1)	—
Total Plan investments	$ 600.4	$ 393.9	$ 170.4	$ 36.1
Receivable from broker for securities sold	—			
Interest and dividends receivable	3.5			
Payable to broker for securities purchased	(22.2)			
Total Plan assets	$ 581.7			

(A) This category represents U.S. treasury notes and bonds with a Moody's Investors Services rating of Aaa and Government Agency Bonds with a Moody's Investors Services rating of A1 or higher.
(B) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common and preferred stocks, U.S. treasury notes and bonds, mutual funds, index funds and interest-bearing cash.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage-backed securities, a commingled fund, a common/collective trust, U.S. municipal bonds, foreign government bonds, money market fund, treasury futures contracts and forward contracts.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Plan's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000 are not entitled to postretirement medical benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges postretirement benefit costs to expense and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

The Company's contribution to the medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. The Company provides Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to a Company-sponsored health reimbursement arrangement. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses.

Plan Investments

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2016 and 2015. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2016 and 2015.

(In millions)	**December 31, 2016**	**Level 1**	**Level 3**
Group retiree medical insurance contract (A)	**$ 44.7**	**$ —**	**$ 44.7**
Mutual funds investment			
U.S. equity investments	**8.1**	**8.1**	**—**
Cash	**0.3**	**0.3**	**—**
Total Plan investments	**$ 53.1**	**$ 8.4**	**$ 44.7**

(In millions)	December 31, 2015	Level 1	Level 3
Group retiree medical insurance contract (A)	$ 46.8	$ —	$ 46.8
Mutual funds investment			
U.S. equity investments	7.8	7.8	—
Money market funds investment	0.7	0.7	—
Total Plan investments	$ 55.3	$ 8.5	$ 46.8

(A) This category represents a group retiree medical insurance contract which invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

The following table summarizes the postretirement benefit plans investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

Year ended December 31 *(In millions)*		**2016**
Group retiree medical insurance contract		
Beginning balance	**$**	**46.8**
Interest income		**0.9**
Dividend income		**0.6**
Net unrealized gains related to instruments held at the reporting date		**0.2**
Realized losses		**(0.1)**
Claims paid		**(3.7)**
Ending balance	**$**	**44.7**

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits.

(In millions)		Gross Projected Postretirement Benefit Payments
2017	$	14.0
2018		14.1
2019		14.1
2020		14.1
2021		14.1
After 2021		69.1

The following table summarizes the benefit payments the Company expects to pay related to OGE Energy's Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

(In millions)		Projected Benefit Payments
2017	$	48.7
2018		48.7
2019		51.9
2020		54.6
2021		55.7
After 2021		290.1

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was $2.4 million and $1.5 million at December 31, 2016 and 2015, respectively.

401(k) Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; (ii) a contribution made on a non Roth after-tax basis; or (iii) a Roth contribution. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election. For employees hired or rehired on or after December 1, 2009, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates. The Company contributed $11.9 million, $11.6 million and $15.2 million in 2016, 2015 and 2014, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on prior participant elections, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2016, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

12. Report of Business Segments

The Company reports its operations in two business segments: (i) the electric utility segment, which is engaged in the generation, transmission, distribution and sale of electric energy, and (ii) natural gas midstream operations segment. Other Operations primarily includes the operations of the holding company.

Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

The following tables summarize the results of the Company's business segments for the years ended December 31, 2016, 2015 and 2014.

2016	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,259.2	$ —	$ —	$ —	$ 2,259.2
Cost of sales	880.1	—	—	—	880.1
Other operation and maintenance	469.8	7.7	(11.9)	—	465.6
Depreciation and amortization	316.4	—	6.2	—	322.6
Taxes other than income	84.0	—	3.6	—	87.6
Operating income (loss)	508.9	(7.7)	2.1	—	503.3
Equity in earnings of unconsolidated affiliates	—	101.8	—	—	101.8
Other income (expense)	27.7	0.1	(4.3)	(0.2)	23.3
Interest expense	138.1	—	4.2	(0.2)	142.1
Income tax expense (benefit)	114.4	40.5	(6.8)	—	148.1

Net income	$ 284.1	$ 53.7	$ 0.4	$ —	$ 338.2
Investment in unconsolidated affiliates	$ —	$ 1,158.6	$ —	$ —	$ 1,158.6
Total assets	$ 8,669.4	$ 1,521.6	$ 89.0	$ (340.4)	$ 9,939.6
Capital expenditures	$ 660.1	$ —	$ —	$ —	$ 660.1

2015	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,196.9	$ —	$ —	$ —	$ 2,196.9
Cost of sales	865.0	—	—	—	865.0
Other operation and maintenance	444.5	7.5	(0.4)	—	451.6
Depreciation and amortization	299.9	—	8.0	—	307.9
Taxes other than income	87.1	—	4.1	—	91.2
Operating income (loss)	500.4	(7.5)	(11.7)	—	481.2
Equity in earnings of unconsolidated affiliates (A)	—	15.5	—	—	15.5
Other income (expense)	20.0	0.4	0.9	(0.3)	21.0
Interest expense	146.7	—	2.6	(0.3)	149.0
Income tax expense (benefit)	104.8	(1.0)	(6.4)	—	97.4
Net income	$ 268.9	$ 9.4	$ (7.0)	$ —	$ 271.3
Investment in unconsolidated affiliates	$ —	$ 1,194.4	$ —	$ —	$ 1,194.4
Total assets	$ 8,525.5	$ 1,439.5	$ 174.6	$ (559.0)	$ 9,580.6
Capital expenditures	$ 551.6	$ —	$ (3.8)	$ —	$ 547.8

(A) In 2015, The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis difference. See Note 3 for further discussion of Enable's goodwill impairment.

2014	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,453.1	$ —	$ —	$ —	$ 2,453.1
Cost of sales	1,106.6	—	—	—	1,106.6
Other operation and maintenance	453.2	1.2	(14.8)	—	439.6
Depreciation and amortization	270.8	—	10.6	—	281.4
Taxes other than income	84.5	—	4.2	—	88.7
Operating income (loss)	538.0	(1.2)	—	—	536.8
Equity in earnings of unconsolidated affiliates	—	172.6	—	—	172.6
Other income (expense)	7.1	—	0.7	(0.2)	7.6
Interest expense	141.5	—	7.1	(0.2)	148.4
Income tax expense (benefit)	111.6	69.1	(7.9)	—	172.8
Net income	292.0	102.3	1.5	—	395.8
Investment in unconsolidated affiliates	$ —	$ 1,318.2	$ —	$ —	$ 1,318.2
Total assets	$ 8,248.9	$ 1,461.2	$ 128.6	$ (328.8)	$ 9,509.9
Capital expenditures	$ 565.4	$ —	$ 10.8	$ (6.9)	$ 569.3

13. Commitments and Contingencies

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases, OG&E wind farm land leases and the Company's noncancellable operating lease. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 *(In millions)*	2017	2018	2019	2020	2021	After 2021	Total
Operating lease obligations							
Railcars	$ 2.7	$ 1.7	$ 21.0	$ —	$ —	$ —	$ 25.4
Wind farm land leases	2.5	2.5	2.5	2.9	2.9	43.5	56.8
Noncancellable operating lease	0.8	0.7	—	—	—	—	1.5
Total operating lease obligations	$ 6.0	$ 4.9	$ 23.5	$ 2.9	$ 2.9	$ 43.5	$ 83.7

Payments for operating lease obligations were $9.3 million, $7.7 million and $6.7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with a purchase option, covering approximately 1,250 rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to fuel expense and are recovered through OG&E's tariffs and fuel adjustment clauses.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed.

On October 14, 2014, OG&E signed a separate three-year lease effective December 2014 for 131 railcars to replace railcars that have been taken out of service or destroyed.

On December 17, 2015, OG&E renewed the lease agreement effective February 1, 2016. At the end of the new lease term, which is February 1, 2019, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $18.3 million. OG&E is also required to maintain all of the railcars it has under the operating lease.

OG&E Wind Farm Land Lease Agreements

OG&E has operating leases related to land for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. The Centennial lease has rent escalations which increase annually based on the Consumer Price Index. The OU Spirit and Crossroads leases have rent escalations which increase after five and 10 years. Although the leases are cancellable, OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their useful life.

Noncancellable Operating Lease

On August 29, 2012, the Company executed a five-year lease agreement for office space from September 1, 2013 to August 31, 2018. This lease has rent escalations which increase after five years and allows for leasehold improvements.

Other Purchase Obligations and Commitments

The Company's other future purchase obligations and commitments estimated for the next five years are as follows:

(In millions)	2017	2018	2019	2020	2021	Total
Other purchase obligations and commitments						
Cogeneration capacity and fixed operation and maintenance payments	$ 77.1	$ 73.9	$ 66.5	$ 54.7	$ 51.0	$ 323.2
Expected cogeneration energy payments	37.7	37.5	38.9	40.7	44.4	199.2
Minimum fuel purchase commitments	236.2	49.3	36.2	24.6	24.6	370.9
Expected wind purchase commitments	59.0	57.9	56.6	57.1	57.5	288.1
Long-term service agreement commitments	2.2	28.4	22.2	2.4	2.4	57.6
Mustang Modernization expenditures	130.4	21.9	—	—	—	152.3
Environmental compliance plan expenditures	169.2	63.0	8.9	0.2	—	241.3
Total other purchase obligations and commitments	$ 711.8	$ 331.9	$ 229.3	$ 179.7	$ 179.9	$ 1,632.6

Public Utility Regulatory Policy Act of 1978

At December 31, 2016, OG&E has a QF contract with Oklahoma Cogeneration LLC which expires on August 31, 2019 and a QF contract with AES-Shady Point, Inc. which expires on January 15, 2023. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MWs AES-Shady Point, Inc. QF contract and the 120 MWs Oklahoma Cogeneration LLC QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2016, 2015 and 2014, OG&E made total payments to cogenerators of $124.8 million, $124.0 million and $129.4 million, respectively, of which $66.3 million, $69.5 million and $72.3 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Sales.

OG&E Minimum Fuel Purchase Commitments

OG&E has coal contracts for purchases through December 2017. As a participant in the SPP Integrated Marketplace, OG&E now purchases a relatively small percentage of its natural gas supply through long-term agreements. Alternatively, OG&E relies on a combination of call natural gas agreements, whereby OG&E has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace.

OG&E Wind Purchase Commitments

OG&E's current wind power portfolio includes the following, in addition to the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms owned by OG&E: (i) access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy that expires in 2018, (ii) access to up to 152 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030, (iii) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2031 and (iv) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2016, 2015 and 2014.

Year ended December 31 *(In millions)*	**2016**	2015	2014
CPV Keenan	**$ 29.2**	$ 26.7	$ 28.1
Edison Mission Energy	**21.1**	19.7	21.3
FPL Energy	**3.4**	3.2	3.6
NextEra Energy	**7.3**	7.0	7.8
Total wind power purchased	**$ 61.0**	$ 56.6	$ 60.8

OG&E Long-Term Service Agreement Commitments

OG&E has a long-term parts and service maintenance contract for the upkeep of the McClain Plant. In May 2013, a new contract was signed that is expected to run for the earlier of 128,000 factored-fired hours or 4,800 factored-fired starts. On December 30, 2015, the McClain LTSA was amended to define the terms and conditions for the exchange of spare rotors between OG&E and General Electric International, Inc. Based on historical usage and current expectations for future usage, this contract is expected to run until 2030. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

OG&E has a long-term parts and service maintenance contract for the upkeep of the Redbud Plant. In March 2013, the contract was amended to extend the contract coverage for an additional 24,000 factored-fired hours resulting in a maximum of the earlier of 144,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2028. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

Enable Gas Transportation Agreement

OG&E contracts with Enable for firm non-notice load following gas transportation services, under a five year contract. The contract will expire in April 2019. In 2016, OG&E entered into an additional gas transportation services contract with Enable which will be effective upon the conversion of units 4 and 5 at Muskogee from coal to gas.

Environmental Laws and Regulations

The activities of OG&E are subject to numerous stringent and complex Federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways including the handling or disposal of waste material, future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. Management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. Historically, OG&E's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

OG&E is managing several significant uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E is unable to predict the financial impact of these matters with certainty at this time.

Air Quality Control System

On September 10, 2014, OG&E executed a contract for the design, engineering and fabrication of two circulating Dry Scrubber systems to be installed at Sooner Units 1 and 2. OG&E entered into an agreement on February 9, 2015, to install the Dry Scrubber systems. The Dry Scrubbers are scheduled to be completed by 2019. More detail regarding the ECP can be found under the "Pending Regulatory Matters" in Note 14.

Clean Power Plan

On October 23, 2015, the EPA published the final Clean Power Plan that established standards of performance for CO_2 emissions from existing fossil-fuel-fired power plants along with state-specific CO_2 reduction standards expressed as both rate-based (lbs/MWh) and mass-based (tons/yr) goals. The 2030 rate-based reduction requirement for all existing generating units in Oklahoma has decreased from a proposed 43 percent reduction to 32 percent in the final rule. The mass-based approach for existing units calls for a 24 percent reduction by 2030 in Oklahoma.

A number of states, including Oklahoma, filed lawsuits against the Clean Power Plan. On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan pending resolution of challenges to the rule. The Company is unable to determine what impact the lawsuits will ultimately have on the Clean Power Plan or what impact the stay in implementation will have; however, if the Clean Power Plan survives judicial review and is implemented as written, it could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Due to the pending litigation and the uncertainties in the state approaches, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time.

Siemens Contract

On June 15, 2015 OG&E entered into a contract with Siemens Energy Inc. for the purchase, design and engineering of seven simple-cycle gas turbine generators for $170.3 million associated with the Mustang Modernization Plan.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits or claims made by third parties, including governmental agencies. When appropriate, management consults with legal counsel and other experts to assess the claim. If, in management's opinion, the Company has incurred a probable loss as set forth by GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. At the present time, based on current available information, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2016, 86 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and six percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid along with the corresponding process for allocating the costs of such expansions. Order No. 1000 requires individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariff and agreement provisions that establish any Federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities or to alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP's pre-Order No. 1000 tariff included a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build previous transmission projects in Oklahoma. On May 29, 2013, the Governor of Oklahoma signed House Bill 1932 into law which establishes a "right of first refusal" for Oklahoma incumbent transmission owners, including OG&E, to build new transmission projects with voltages under 300kV that interconnect to those incumbent owners' existing facilities.

The SPP has submitted compliance filings implementing Order No. 1000's requirements. In response, the FERC issued an order on the SPP filings that required the SPP to remove certain "right of first refusal" language from the SPP Tariff and the SPP Membership Agreement. On December 15, 2014, OG&E filed an appeal in the Court challenging the FERC's order requiring the removal of the "right of first refusal" language from the SPP Membership Agreement.

On July 1, 2016, the Court upheld the FERC's decision requiring removal of the "right of first refusal" for incumbent transmission providers from the SPP Membership Agreement. The Court determined that the FERC had reasonably found the "right of first refusal" in the SPP Membership Agreement to be anticompetitive.

The Company does not believe the Court’s ruling will have any impact on existing transmission projects for which the Company has already received a notice to construct from the SPP. The Company intends to actively participate in the SPP planning process for competitive transmission projects that we believe apply to transmission voltage levels projects greater than 300kV.

Fuel Adjustment Clause Review for Calendar Year 2014

On July 28, 2015, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2014, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On May 26, 2016, the OCC issued a final order, finding that for the calendar year 2014 OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent.

Oklahoma Demand Program Rider Review - SmartHours Program

In July 2012, OG&E filed an application with the OCC to recover certain costs associated with demand programs through the Oklahoma Demand Program Rider, including the lost revenues associated with the SmartHours program. The SmartHours program is designed to incentivize participating customers to reduce on-peak usage or shift usage to off-peak hours during the months of May through October, by offering lower rates to those customers in the off-peak hours of those months. Lost revenues are created by the difference in the standard rates and the lower incentivized rates. Non-SmartHours program customers benefit from the reduction of on-peak usage by SmartHours customers by the reduction of more costly on-peak generation and the delay in adding new on-peak generation.

In December 2012, the OCC issued an order approving the recovery of costs associated with the demand programs, including the lost revenues associated with the SmartHours program, subject to the PUD Staff's review.

In March 2014, the PUD Staff began their review of the demand program costs, including the lost revenues associated with the SmartHours program.

On August 9, 2016, OG&E entered into a settlement agreement with the PUD Staff to resolve the recoverable amount of lost revenues associated with the SmartHours program. The settlement provides for recovery of $10.1 million per year for 2013, 2014 and 2015, for a total of $30.3 million. OG&E had recorded $36.6 million of lost revenues for 2013, 2014 and 2015. On August 16, 2016, the OCC issued an order adopting the settlement agreement. Accordingly, OG&E reduced lost revenues and the Oklahoma Demand Program Rider regulatory asset by $6.3 million.

Mustang Modernization Plan - Arkansas

On April 13, 2016, OG&E filed an application at the APSC seeking authority to construct combustion turbines at its existing Mustang generating facility. Arkansas law requires a public utility to seek approval from the APSC to construct a power-generating facility located outside the boundaries of the state of Arkansas. The application did not seek any cost recovery for the capital expenditures in the application, as cost recovery will be determined in future proceedings. In July 2016, OG&E filed a motion to dismiss this proceeding and in August, the APSC approved the dismissal. OG&E intends to seek cost recovery of the Mustang combustion turbines at a later date after the Mustang facility is placed in service.

Pending Regulatory Matters

Set forth below is a list of various proceedings pending before state or federal regulatory agencies. Unless stated otherwise, OG&E cannot predict when the regulatory agency will act or what action the regulatory agency will take. OG&E's financial results are dependent in part on timely and adequate decisions by the regulatory agencies that set OG&E's rates.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA’s MATS and Regional Haze Rule FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP and for a recovery mechanism for the associated costs. The ECP includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asked the OCC to predetermine the prudence of its Mustang Modernization Plan, which calls for replacing OG&E's soon-to-be retired Mustang steam turbines with 400 MWs of new, efficient combustion turbines at the Mustang site and approval for a recovery mechanism for the associated costs.

On December 2, 2015, OG&E received an order from the OCC denying its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze Rule and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving its decision to install Dry Scrubbers at the Sooner facility. OG&E's application did not seek approval of the costs of the Dry Scrubber project. Instead, the reasonableness of the costs would be considered after the project is completed and OG&E seeks recovery in its rates. On April 28, 2016, the OCC approved the Dry Scrubber project.

Two parties appealed the OCC's decision to the Oklahoma Supreme Court. The Company is unable to predict what action the Oklahoma Supreme Court may take or the timing of any such action.

OG&E anticipates the total cost of Dry Scrubbers will be $547.5 million, including allowance for funds used during construction and capitalized ad valorem taxes. As of December 31, 2016, OG&E had invested $208.7 million of construction work in progress on the Dry Scrubbers. OG&E anticipates the total cost for the Mustang Modernization Plan will be $424.9 million and expects the project to be completed in late 2017. As of December 31, 2016, OG&E had invested $187.8 million on the Mustang Modernization Plan.

Integrated Resource Plans

In October 2015, OG&E finalized the 2015 IRP and submitted it to the OCC. The 2015 IRP updated certain assumptions contained in the IRP submitted in 2014, but did not make any material changes to the ECP and other parts of the plan. Currently, OG&E is scheduled to update its IRP in Arkansas by October 1, 2017 and in Oklahoma by October 1, 2018.

Oklahoma Rate Case Filing

On December 18, 2015, OG&E filed a general rate case with the OCC requesting a rate increase of $92.5 million and a 10.25 percent return on equity based on a common equity percentage of 53 percent. The rate case was based on a June 30, 2015 test year and included recovery of $1.6 billion of electric infrastructure additions since its last general rate case in Oklahoma, the impact of the expiration of OG&E's wholesale contracts, increased operating costs such as vegetation management and increased recovery of depreciation and plant dismantlement of approximately $8.0 million. Each 0.25 percent change in the requested return on equity affects the requested rate increase by approximately $9.0 million.

In late March 2016, the PUD Staff and other intervenors filed testimony in the case. The PUD Staff recommended a $6.1 million annual rate increase based on a return on equity of 9.25 percent and a common equity percentage of 53 percent. Included in the PUD Staff's recommendation is a reduction of $33.0 million to OG&E’s requested increase for depreciation and plant dismantlement.

The staff of the Oklahoma Attorney General made a recommendation to reduce rates $10.8 million based on a return on equity of 9.25 percent and a common equity percentage of 50 percent, as well as a recommendation to reduce rates $13.7 million based on a return on equity of 8.90 percent and a common equity percentage of 53 percent. Included in the Oklahoma Attorney General's recommendation is a reduction of $20.9 million to OG&E’s requested increase for depreciation and plant dismantlement.

The Oklahoma Industrial Energy Consumers recommended a $47.9 million annual rate decrease based on a return on equity of 9.00 percent and a common equity percentage of 53 percent. Included in the Oklahoma Industrial Energy Consumers' recommendation is a reduction of $52.5 million to OG&E’s requested increase for depreciation and plant dismantlement.

On July 1, 2016, OG&E implemented an annual interim rate increase of $69.5 million which is subject to refund of any amount recovered in excess of the rates ultimately approved by the OCC in the rate case. As of December 31, 2016, the Company has recorded $39.0 million of revenues from the interim rate increase and has reserved $33.7 million of that revenue.

In December 2016, the ALJ issued a report and recommendations in the case. The ALJ's recommendations include, among other things, the use of OG&E's actual capital structure of 53 percent equity and 47 percent long-term debt and a return on equity of 9.87 percent resulting in an annual increase in OG&E's revenues of $40.7 million. The parties provided comments on the ALJ's report in early January 2017, and the OCC held hearings in early February 2017. The Company is unable to predict what action the OCC will take, or the timing of such action.

Arkansas Rate Case Filing

On August 25, 2016, OG&E filed a general rate case with the APSC. The rate filing requested a $16.5 million rate increase based on a 10.25 percent return on equity. The rate increase was based on a June 30, 2016 test year and included a recovery of over $3.0 billion of electric infrastructure additions since the last Arkansas general rate case in 2011. The increase also reflects increases in operation and maintenance expenses, including vegetation management costs, and increased recovery of depreciation and dismantlement costs. A hearing in this matter is scheduled for the second quarter of 2017.

Fuel Adjustment Clause Review for Calendar Year 2015

On September 8, 2016, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2015, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. A hearing in this Cause will be held on March 30, 2017.

15. Quarterly Financial Data (Unaudited)

Due to the seasonal fluctuations and other factors of the Company's businesses, the operating results for interim periods are not necessarily indicative of the results that may be expected for the year. In the Company's opinion, the following quarterly financial data includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present such amounts. Summarized consolidated quarterly unaudited financial data is as follows:

Quarter ended (*In millions, except per share data)*		March 31	June 30	September 30	December 31	Total
Operating revenues	**2016**	**$ 433.1**	**$ 551.4**	**$ 743.9**	**$ 530.8**	**$ 2,259.2**
	2015	$ 480.1	$ 549.9	$ 719.8	$ 447.1	$ 2,196.9
Operating income	**2016**	**$ 37.9**	**$ 125.9**	**$ 257.3**	**$ 82.2**	**$ 503.3**
	2015	$ 56.4	$ 127.2	$ 250.8	$ 46.8	$ 481.2
Net income	**2016**	**$ 25.2**	**$ 71.5**	**$ 183.6**	**$ 57.9**	**$ 338.2**
	2015	$ 43.2	$ 87.5	$ 111.2	$ 29.4	$ 271.3
Basic earnings per average common share (A)	**2016**	**$ 0.13**	**$ 0.35**	**$ 0.92**	**$ 0.29**	**$ 1.69**
	2015	$ 0.22	$ 0.44	$ 0.55	$ 0.15	$ 1.36
Diluted earnings per average common share (A)	**2016**	**$ 0.13**	**$ 0.35**	**$ 0.92**	**$ 0.29**	**$ 1.69**
	2015	$ 0.22	$ 0.44	$ 0.55	$ 0.15	$ 1.36

(A) Due to the impact of dilution on the earnings per share calculation, quarterly earnings per share amounts may not add to the total.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of OGE Energy Corp. (the Company) as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2016. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits. We did not audit the consolidated financial statements of Enable Midstream Partners, LP (Enable), a partnership in which the Company has a 25.7 percent interest at December 31, 2016. The Company’s investment in Enable constituted 11.7 percent and 12.5 percent of the Company’s total assets as of December 31, 2016 and 2015, respectively, and the Company’s equity earnings in the net income of Enable constituted 20.9 percent, 4.2 percent and 30.4 percent of the Company’s income before taxes for the years ended December 31, 2016, 2015 and 2014, respectively. Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Enable, is based solely on the report of the other auditors.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits and the report of other auditors provide a reasonable basis for our opinion.

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2016 and 2015, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2016, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 22, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 22, 2017

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

Management's Report on Internal Control Over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (2013). Based on our assessment, we believe that, as of December 31, 2016, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on the Company's internal control over financial reporting. This report appears on the following page.

/s/ Sean Trauschke	/s/ Scott Forbes
Sean Trauschke, Chairman of the Board, President and Chief Executive Officer	Scott Forbes, Controller and Chief Accounting Officer
/s/ Stephen E. Merrill	
Stephen E. Merrill Chief Financial Officer	

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). OGE Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2016 of OGE Energy Corp. and our report dated February 22, 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

February 22, 2017

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Code of Ethics Policy

OGE Energy maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on OGE Energy's website address www.oge.com under the heading "Investors," "Investor Relations," "Corporate Governance." The code of ethics will be provided, free of charge, upon request. OGE Energy intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its website at the location specified above. OGE Energy will also include in its proxy statement information regarding the Audit Committee financial experts.

Item 11. Executive Compensation.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Item 14. Principal Accounting Fees and Services.

Items 10 through 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 31, 2017. Such proxy statement is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) 1. Financial Statements

(i) The following Consolidated Financial Statements are included in Part II, Item 8 of this Annual Report:

- Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2016, 2015 and 2014
- Consolidated Statements of Cash Flows for the years ended December 31, 2016, 2015 and 2014
- Consolidated Balance Sheets at December 31, 2016 and 2015
- Consolidated Statements of Capitalization at December 31, 2016 and 2015
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2016, 2015 and 2014
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)
- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm (Audit of Internal Control over Financial Reporting)

(ii) The financial statements and Notes to Consolidated Financial Statements of Enable Midstream Partners, LP, required pursuant to Rule 3-09 of Regulation S-X are filed as Exhibit 99.06

2. Financial Statement Schedule (included in Part IV)

- Schedule II - Valuation and Qualifying Accounts

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective Consolidated Financial Statements or Notes thereto.

3. Exhibits

Exhibit No.	Description
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein).
2.02	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.03	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.04	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.05	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.06	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein).
2.07	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein).
2.08	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein).
2.09	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
2.10	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
2.11	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
2.12	Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein).
2.13	Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein).
2.14	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed March 15, 2013 (File No. 1-12579) and incorporated by reference herein).
3.01	Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12579) and incorporated by reference herein).
3.02	Copy of Amended OGE Energy Corp. By-laws dated February 22, 2017. (Filed as Exhibit 3.01 to OGE Energy's Form 8-K filed February 22, 2017 (File No. 1-12579) and incorporated by reference herein).
4.01	Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein).
4.02	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein).

4.03	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein).
4.04	Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein).
4.05	Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein).
4.06	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein).
4.07	Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (File No. 1-1097) and incorporated by reference herein).
4.08	Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein).
4.09	Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein).
4.10	Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein).
4.11	Supplemental Indenture No. 12 dated as of May 15, 2011 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 27, 2011 (File No. 1-1097) and incorporated by reference herein).
4.12	Supplemental Indenture No. 13 dated as of May 1, 2013 between OG&E and UMB Bank, N.A., as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 13, 2013 (File No. 1-1097) and incorporated by reference herein).
4.13	Supplemental Indenture No. 14 dated as of March 15, 2014 between OG&E and UMB Bank, N.A., as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed March 25, 2014 (File No. 1-1097) and incorporated by reference herein).
4.14	Supplemental Indenture No. 15 dated as of December 1, 2014 between OG&E and UMB Bank, N.A., as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2014 (File No. 1-1097) and incorporated by reference herein).
4.15	Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein).
4.16	Supplemental Indenture No. 2 dated as of November 24, 2014 between OGE Energy and UMB Bank, N.A, as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 24, 2014 (File No. 1-12579) and incorporated by reference herein).
10.01	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 9, 2012 (File No. 1-12579) and incorporated by reference herein).
10.02	Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
10.03	Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
10.04	Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein).
10.05*	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein).
10.06	Credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein).

10.07	Credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein).
10.08*	OGE Energy Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein).
10.09*	OGE Energy Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein).
10.10*	Form of Employment Agreement for all existing and future officers of the Company relating to change of control. (Filed as Exhibit 10.28 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein).
10.11*	Form of Restricted Stock Agreement under OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12579) and incorporated by reference herein).
10.12	Agreement, dated February 17, 2010, between OG&E and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein).
10.13*	Amendment No. 1 to OGE Energy's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein).
10.14	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 1, 2010 (File No. 1-12579) and incorporated by reference herein).
10.15	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed July 1, 2010 (File No. 1-12579) and incorporated by reference herein).
10.16	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed May 19, 2011 (File No. 1-12579) and incorporated by reference herein).
10.17	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed June 28, 2011 (File No. 1-12579) and incorporated by reference herein).
10.18*	Director Compensation.
10.19*	Executive Officer Compensation.
10.20	Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP, dated June 22, 2016 (Filed as Exhibit 10.01 to the Company's Form 8-K filed June 22, 2016 (File No. 1-12579) and incorporated by reference herein).
10.21	Third Amended and Restated Limited Liability Company Agreement of Enable GP, LLC, dated June 22, 2016(Filed as Exhibit 10.02 to the Company's Form 8-K filed June 22, 2016 (File No. 1-12579) and incorporated by reference herein).
10.22	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CenterPoint Energy Resources Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC (Filed as Exhibit 10.03 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein).
10.23	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP (Filed as Exhibit 10.04 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein).
10.24*	OGE Energy's 2013 Stock Incentive Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein).
10.25*	OGE Energy's 2013 Annual Incentive Compensation Plan. (Filed as Annex C to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein).
10.26	Letter of extension dated as of July 29, 2013 for OGE Energy's credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed August 2, 2013 (File No. 1-12579) and incorporated by reference herein).

10.27	Letter of extension dated as of July 29, 2013 for OG&E's credit agreement dated as of December 13,2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed August 2, 2013 (File No. 1-12579) and incorporated by reference herein).
10.28*	OGE Energy Corp. Involuntary Severance Benefits Plans for Non-Officers (Applicable only to non-officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein).
10.29*	OGE Energy Corp. Involuntary Severance Benefits Plans for Officers (Applicable only to officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein).
10.30*	Retention Agreement effective as of October 24, 2013, by and between OGE Enogex Holdings, LLC and E. Keith Mitchell (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein).
10.31	Letter of extension dated as of June 24, 2014 for OGE Energy's credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed June 25, 2014 (File No. 1-12579) and incorporated by reference herein).
10.32	Letter of extension dated as of June 24, 2014 for OG&E's credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed June 25, 2014 (File No. 1-12579) and incorporated by reference herein).
10.33	Letter of extension dated as of September 8, 2014 for OGE Energy's credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q filed November 5, 2014 (File No. 1-12579) and incorporated by reference herein).
10.34	Letter of extension dated as of June 24, 2014 for OG&E's credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed June 25, 2014 (File No. 1-12579) and incorporated by reference herein).
10.35*	Form of Performance Unit Agreement under OGE Energy's 2013 Stock Incentive Plan.
10.36*	Form of Restricted Stock Agreement under OGE Energy's 2013 Stock Incentive Plan.
10.37	OGE Energy Corp. Deferred Compensation Plan (As amended and restated effective October 1, 2016.)
12.01	Calculation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
23.02	Consent of Deloitte & Touche LLP for the Financial Statements of Enable Midstream Partners, LP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Copy of APSC order with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 22, 2011 (File No. 1-12579) and incorporated by reference herein).
99.02	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 7, 2010 (File No. 1-12579) and incorporated by reference herein).
99.03	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein).
99.04	Description of Capital Stock. (Filed as Exhibit 99.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12579) and incorporated by reference herein).
99.05	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2016.

99.06	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2013 (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed November 12, 2014 (File No. 1-12579) and incorporated by reference herein).
99.07	Copy of the Report of Administrative Law Judge dated June 8, 2015. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 12, 2015 (File No. 1-12579) and incorporated by reference herein).
99.08	Copy of OCC Order relating to OG&E's environmental compliance plan application (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 7, 2015 (File No. 1-12579) and incorporated by reference herein).
99.09	Copy of OG&E's Motion for Rehearing on its environmental compliance plan application (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 15, 2015 (File No. 1-12579) and incorporated by reference herein).
99.10	Copy of OG&E's Application with the OCC for general rate case (Filed and Exhibit 99.02 to OGE Energy's Form 8-K filed December 23, 2015 (File No. 1-12579) and incorporated by reference herein).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* Represents executive compensation plans and arrangements.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Deductions (A)	Balance at End of Period
	(In millions)			
Balance at December 31, 2014				
Reserve for Uncollectible Accounts	$ 1.9	$ 2.3	$ 2.6	$ 1.6
Balance at December 31, 2015				
Reserve for Uncollectible Accounts	$ 1.6	$ 2.4	$ 2.6	$ 1.4
Balance at December 31, 2016				
Reserve for Uncollectible Accounts	**$ 1.4**	**$ 2.5**	**$ 2.4**	**$ 1.5**

(A) Uncollectible accounts receivable written off, net of recoveries.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on February 22, 2017.

OGE ENERGY CORP.
(Registrant)

By /s/ Sean Trauschke
Sean Trauschke
Chairman of the Board, President
and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Sean Trauschke Sean Trauschke	Principal Executive Officer and Director;	February 22, 2017
/s/ Stephen E. Merrill Stephen E. Merrill	Principal Financial Officer;	February 22, 2017
/s/ Scott Forbes Scott Forbes	Principal Accounting Officer.	February 22, 2017
Frank A. Bozich	Director;	
James H. Brandi	Director;	
Luke R. Corbett	Director;	
John D. Groendyke	Director;	
David L. Hauser	Director;	
Kirk Humphreys	Director;	
Robert O. Lorenz	Director;	
Judy R. McReynolds	Director;	
Sheila G. Talton	Director;	
/s/ Sean Trauschke By Sean Trauschke (attorney-in-fact)		February 22, 2017

Exhibit 10.18

OGE Energy Corp.
Director Compensation

Compensation of non-officer directors of the Company in 2016 included an annual retainer fee of $162,600, of which $57,600 was payable in cash in quarterly installments and $105,000 was deposited in the director's account under the Company's Deferred Compensation Plan and converted to 3,277 common stock units based on the closing price of the Company's Common Stock on December 6, 2016. All non-officer directors received $2,000 for each Board meeting and $2,000 for each committee meeting attended. The lead director received an additional $20,000 cash retainer in 2016. The chair of the Audit Committee received an additional $15,000 cash retainer in 2016. The chair of the Compensation and Nominating and Corporate Governance Committees received an additional $10,000 annual cash retainer in 2016. Each member of the Audit Committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E in 2016.

Under the Company's Deferred Compensation Plan, non-officer directors may defer payment of all or part of their attendance fees and the quarterly cash retainer fee, which deferred amounts in 2016 were credited to their account as of the first day of the quarterly scheduled payment date. Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Company's Deferred Compensation Plan. In 2016, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock. When an individual ceases to be a director of the Company, all amounts credited under the Company's Deferred Compensation Plan are paid in cash in a lump sum or installments. In certain circumstances, participants may also be entitled to in-service withdrawals from the Company's Deferred Compensation Plan.

On November 30, 2016, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the annual equity retainer, noted above, credited on December 6, 2016, from $95,000 to $105,000. The Compensation Committee also determined to make a change in the annual cash retainer and cease paying for meeting fees effective for 2017. The annual cash retainer was set at $100,000 for 2017 to be paid quarterly.

Exhibit 10.19

OGE Energy Corp.
Executive Officer Compensation

Executive Compensation

In December 2016, the Compensation Committee of the OGE Energy Corp. board of directors took actions setting executives' salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2017. Executive compensation was set by the Compensation Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2017 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals established by the Compensation Committee and no officer is assured of any payout.

Salary

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2017 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2017 Proxy Statement are as follows:

Executive Officer	2017 Base Salary
Sean Trauschke, Chairman, President and Chief Executive Officer	$950,000
Stephen E. Merrill, Chief Financial Officer	$462,000
E. Keith Mitchell, Chief Operating Officer of OG&E	$498,623
Jean C. Leger, Jr., Vice President - Utility Operations of OG&E	$360,882
Paul Renfrow, Vice President - Public Affairs and Corporate Administration	$365,547

Establishment of 2017 Annual Incentive Awards

As stated above, at its December 2016 meeting, the Compensation Committee approved the target amount of annual incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of the 2017 corporate goals to receive from 0 percent to 150 percent of such targeted amount. For 2017, the targeted amount ranged from 60 percent to 100 percent of the approved 2017 base salary for the executive officers in the above table.

Establishment of Long-Term Awards

At its December 2016 meeting, the Compensation Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary, with the officer having the ability to receive from 0 percent to 200 percent of such targeted amount at the end of a three-year performance period depending upon achievement of the corporate goals. For 2017, the targeted amount ranged from 115 percent to 290 percent of the approved 2017 base salary for the executive officers in the above table.

Other Benefits

Retirement Benefits. A significant amount of the Company's employees hired before December 1, 2009, including executive officers, are eligible to participate in the Company's Pension Plan and certain employees are eligible to participate in the Company's Restoration of Retirement Income Plan that enables participants, including executive officers, to receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. In addition, the supplemental executive retirement plan, which was adopted in 1993, provides a supplemental executive retirement plan in order to attract and retain executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. As of December 31, 2015, there are no employees participating in the supplemental executive retirement plan.

Almost all employees of the Company, including executive officers, also are eligible to participate in our 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; (ii) a contribution made on a non Roth after-tax basis; or (iii) a Roth contribution. The 401

(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election. For employees hired or rehired on or after December 1, 2009, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace. Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers.

The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on prior participant elections, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2016, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement will receive their vested account balance in one lump sum following termination as provided in the plan. Participants also will be entitled to pre- and post-retirement survivor benefits. If the participant dies while in employment before retirement, his or her beneficiary will receive a payment of the account balance plus a supplemental survivor benefit equal to two times the total amount of base salary and bonuses deferred under the plan. If the participant dies following retirement, his or her beneficiary will continue to receive the remaining vested account balance. Additionally, eligible surviving spouses will be entitled to a lifetime survivor annuity payable annually. The amount of the annuity is based on 50 percent of the participant's account balance at retirement, the spouse's age and actuarial assumptions established by the Company's Plan Administration Committee.

At any time prior to retirement, a participant may withdraw all or part of amounts attributable to his or her vested account balance under the deferred compensation plan at December 31, 2004, subject to a penalty of 10 percent of the amount withdrawn. In addition, at the time of the initial deferral election, a participant may elect to receive one or more in-service distributions on specified dates without penalty. Hardship withdrawals, without penalty, of amounts attributable to a participant's vested account balance may also be permitted at the discretion of the Company's Plan Administration Committee.

Perquisites. The Company also offers executive officers a limited amount of perquisites. These include payment of social membership dues at dining and country clubs for certain executive officers, an annual physical exam for all executive officers, a relocation program and in some instances the use of a Company car. In reviewing the perquisites and the benefits under the 401

(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee seeks to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

Change-of-Control Provisions and Employment Agreements. None of the Company's executive officers has an employment agreement with the Company. Each of the executive officers has a change of control agreement that becomes effective upon a change of control. If an executive officer's employment is terminated by the Company "without cause" following a change of control, the executive officer is entitled to the following payments: (i) all accrued and unpaid compensation and a prorated annual bonus and (ii) a severance payment equal to 2.99 times the sum of such officer's (a) annual base salary and (b) highest recent annual bonus. The change of control agreements are considered to be double trigger agreements because payment will only be made following a change of control and termination of employment. The 2.99 times multiple for change-of-control payments was selected because at the time it was considered standard. Although many companies also include provisions for tax gross-up payments to cover any excise taxes on excess parachute payments, the Company's Board of Directors decided not to include this additional benefit in the Company's agreements. Instead, under the Company's agreements if the excise tax would be imposed, the change-of-control payments will be reduced to a point where no excise tax would be payable, if such reduction would result in a greater after-tax payment.

In addition, pursuant to the terms of the Company's incentive compensation plans, upon a change of control, all stock options and restricted stock will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding for the year in which the participant's termination occurs for any reason, other than cause, within 24 months after the change of control will be paid in cash at target level on a prorated basis.

Exhibit 10.35

OGE ENERGY CORP.
FORM OF PERFORMANCE UNIT AGREEMENT
UNDER THE 2013 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards, at target, to __________ (the "Participant") __ Performance Units pursuant to the OGE Energy Corp. 2013 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on __________ and ending on __________ (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on the performance of the Company's total shareholder return relative to the total shareholder return of all of the companies (the "S&P Companies") comprising the Standard and Poor's 1500 Utilities Index as of __________ and __________ (or their successors from a merger or other combination with another company listed in such Index, but excluding any company subject to a Business Combination, as hereinafter defined on __________). Total shareholder return ("TSR") for any company, including the Company, shall include both price appreciation (depreciation) and cash dividends, shall be calculated in the same manner that Standard and Poor's calculated total return as of __________ and shall be measured by the company's total return that shareholders receive over the Award Cycle by investment at the first day of the Award Cycle.

   The number of Performance Units earned is dependent on the performance ranking of the Company's total shareholder return for the Award Cycle, as set forth below (expressed in terms of the Company's position among the S&P Companies when ranked by total shareholder return for the Award Cycle):

COMPANY TSR PERCENTILE RANKING VS. S&P COMPANIES	PERCENT OF TARGET PERFORMANCE UNITS EARNED
__ percentile	200%
__ percentile	175%
__ percentile	150%
__ percentile	125%
__ percentile	100%
__ percentile	75%
__ percentile	50%
__ percentile	25%
Below __ percentile	0%

   Performance Units earned for performance between the percentiles shown above will be determined by straight-line interpolation; provided, that, in all cases, the number of Performance Units which the Participant earns shall be a whole number (disregarding any fraction).

   Any Performance Units awarded hereunder that the Participant does not earn at the end of the Award Cycle pursuant to the foregoing schedule shall be forfeited.

The provisions of this Section 2 shall not affect in any way any forfeiture under Section 4 below or Section 8(b) of the Plan or any provision regarding the earning of Performance Units at the 100% target level under Section 9 of the Plan upon the occurrence of a Change of Control.

For purposes of determining whether any of the S&P Companies is subject to a Business Combination on __________, a company shall be deemed subject to a Business Combination on __________, if such company is: (i) the subject of a tender offer or exchange offer by a third party seeking to acquire more than 20% of the outstanding voting securities of such company or (ii) a party to a merger, consolidation, share exchange or reorganization agreement or an agreement providing for the sale or disposition of all or substantially all of its assets.

3. Payout. Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, the Committee shall evaluate the actual performance of the Performance Goal set forth in Section 2 hereof, shall certify in writing the extent to which such Performance Goal and other material terms of this award have been satisfied and shall determine the number, if any, of Performance Units that have been earned (the "Earned Performance Units"). The Committee shall then cause to be issued to the Participant (or, in the event of the Participant's death, to the Participant's beneficiary under the Plan) no later than __________: (i) a certificate for shares of Common Stock equal in number to the Earned Performance Units (disregarding any fraction) plus a cash payment equal to the amount of dividends that would have been declared during the Award Cycle on such number of shares of Common Stock being issued pursuant to this Section 3.

4. Forfeiture. All Performance Unit awards are subject to the terms and conditions of the Plan relating to Performance Units. If the Participant incurs a Termination of Employment for any reason on or before the end of the Award Cycle, all rights to or in respect of Performance Units awarded hereunder shall be forfeited except as provided in Section 8(b)(iii) or Section 9(a)(iii) of the Plan and except that, in the case of the Participant's Termination of Employment after he has at least 80 Points as defined in Section 2.49 of the OGE Energy Corp. Retirement Plan, as amended and restated effective January 1, 2013, such Termination of Employment will be considered a Termination of Employment due to Retirement under Section 8(b)(iii) of the Plan.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan, and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, the total shareholder return of the Company or any other company for the Award Cycle.

6. Taxes and Other Matter.

(a) By execution of this Agreement, the Participant agrees to pay all withholding and other taxes payable by the Participant with respect to Performance Units earned under this Agreement at such times and in such manner as the Company may request, and the Participant further agrees to comply with all Federal and State securities laws.

(b) The Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant’s minimum tax withholding requirements under Federal, State and local laws and regulations thereunder, in whole or in part, by having the Company withhold shares having a fair market value equal to all or a portion of the amount so required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable and (ii) made electronically through the Common Stock Plan Services Administrator (or by such other method as the Committee determines) prior to the date on which the Committee will determine the number of Performance Units earned hereunder or such earlier date as the Company shall prescribe.

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to your acceptance of this Agreement.

OGE ENERGY CORP.

BY: ____

Chairman of the Board and
Chief Executive Officer

ACCEPTED AND AGREED TO this __________ day of ________________________________

____
Participant

OGE ENERGY CORP.
FORM OF PERFORMANCE UNIT AGREEMENT
UNDER THE 2013 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards, at target, to __________ (the "Participant") __ Performance Units pursuant to the OGE Energy Corp. 2013 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on January 1, 2016 and ending on December 31, 2018 (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on Utility EPS Growth during the Award Cycle. Utility EPS Growth shall mean the amount obtained by multiplying one-third times the percentage increase or decrease in Utility EPS for the year ended December 31, 2018 as compared to $1.35 for the year ended December 31, 2015. Utility EPS shall mean the sum of: (x) the Net Income as shown on the Statement of Income of Oklahoma Gas and Electric Company for the year ended December 31, 2018 plus (y) the Net Income of OGE Transmission Company as shown on the Statement of Income of OGE Transmission Company for the year ended December 31, 2018, divided by the same number of outstanding shares of common stock used in calculating consolidated diluted earnings per average common share from continuing operations of OGE Energy Corp., as reported on the Consolidated Statement of Income of OGE Energy Corp. for the year ended December 31, 2018. For purposes of the foregoing, all percentages shall be calculated to the nearest one-hundredth of one percent. The number of Performance Units earned for the Award Cycle shall be determined in accordance with the following chart:

UTILITY'S AVERAGE EARNINGS PER SHARE GROWTH	PERCENT OF TARGET PERFORMANCE UNITS EARNED
7.0%	200%
6.3%	180%
5.6%	160%
4.9%	140%
4.2%	120%
3.5%	100%
3.0%	87.5%
2.5%	75%
2.0%	62.5%
1.5%	50%
Below 1.5%	0%

Performance Units earned for performance between the percentiles shown above will be determined by straight-line interpolation; provided, that, in all cases, the number of Performance Units which the Participant earns shall be a whole number (disregarding any fraction).

Any Performance Units awarded hereunder that the Participant does not earn at the end of the Award Cycle pursuant to the foregoing chart shall be forfeited.

The provisions of this Section 2 shall not affect in any way any forfeiture under Section 4 below or Section 8(b) of the Plan or any provision regarding the earning of Performance Units at the 100% target level under Section 9 of the Plan upon the occurrence of a Change of Control.

3. Payout. Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, the Committee shall evaluate the actual performance of the Performance Goal set forth in Section 2 hereof, shall certify in writing the extent to which such Performance Goal and other material terms of this award have been satisfied and shall determine the number, if any, of Performance Units that have been earned (the "Earned Performance Units"). The Committee shall then cause to be issued to the Participant (or, in the event of the Participant's death, to the Participant's beneficiary under the Plan) no later than March 15, 2019: (i) a certificate for shares of Common Stock equal in number to the Earned Performance Units (disregarding any fraction) plus (ii) a cash payment equal to the amount of dividends that would have been declared during the Award Cycle on such number of shares of Common Stock being issued pursuant to this Section 3.

4. Forfeiture. All Performance Unit awards are subject to the terms and conditions of the Plan relating to Performance Units. If the Participant incurs a Termination of Employment for any reason on or before the end of the Award Cycle, all rights to or in respect of Performance Units awarded hereunder shall be forfeited except as provided in Section 8(b)(iii) or Section 9(a)(iii) of the Plan and except that, in the case of the Participant's Termination of Employment after he has at least 80 Points as defined in Section 2.49 of the OGE Energy Corp. Retirement Plan, as amended and restated effective January 1, 2013, such Termination of Employment will be considered a Termination of Employment due to Retirement under Section 8(b)(iii) of the Plan.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan, and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, earnings per share of the Company for any period.

6. Taxes and Other Matter.

(a) By execution of this Agreement, the Participant agrees to pay all withholding and other taxes payable by the Participant with respect to Performance Units earned under this Agreement at such times and in such manner as the Company may request, and the Participant further agrees to comply with all Federal and State securities laws.

(b) The Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant’s minimum tax withholding requirements under Federal, State and local laws and regulations thereunder, in whole or in part, by having the Company withhold shares having a fair market value equal to all or a portion of the amount so required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable and (ii) made electronically through the Common Stock Plan Services Administrator (or by such other method as the Committee determines) prior to the date on which the Committee will determine the number of Performance Units earned hereunder or such earlier date as the Company shall prescribe.

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to your acceptance of this Agreement.

OGE ENERGY CORP.

BY: ______________________________

Chairman of the Board and
Chief Executive Officer

ACCEPTED AND AGREED TO this _________ day of ______________________________

____
Participant

Exhibit 10.36

OGE ENERGY CORP.
FORM OF RESTRICTED STOCK UNITS AGREEMENT
UNDER THE 2013 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards to [_________] (the "Participant") [________] Restricted Stock Units (the “Units”) pursuant to the OGE Energy Corp. 2013 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. <u>Restrictions on Transfer and Restriction Periods</u>.

(a) During the respective periods hereinafter described in Section 1(b) (the Restriction Periods”), the Units may not be sold, assigned, transferred, pledged, or otherwise encumbered by the Participant and shall be subject to a risk of forfeiture, except as hereinafter provided.

(b) The restrictions described above shall commence on the date of this Agreement (the “Grant Date”) and, except as provided in Section 1(d) or Section 2, shall lapse with respect to one-third (33.3%) of the Units on the first anniversary of the Grant Date, one-third (33.3%) of the Units on the second anniversary of the Grant Date and with respect to the remaining Units on the third anniversary of the Grant Date.

(c) The number of shares of Common Stock covered by this award is equal to the number of Units.

(d) Absent a prior forfeiture, each Unit subject to this Agreement shall vest and shall represent the right to receive one share of Common Stock, and related dividends as described below, upon the expiration of the Restriction Period applicable to such Unit or, if earlier, upon a Change of Control as defined in the Plan or upon a waiver of the restrictions applicable to such Unit as described below in Section 2. The date on which a Unit vests is hereinafter referred to as the "Vesting Date."

2. <u>Termination of Service</u>.

If the Participant has a Termination of Employment (as defined on the Plan), all Units which are then subject to the restrictions imposed by Section 1 shall be forfeited and of no further effect; provided, however, that if the Participant ceases employment by reason of Retirement (as defined in the Plan) or involuntary termination, the Compensation Committee (the “Compensation Committee”) of the Company’s Board of Directors may waive all remaining restrictions.

3. <u>Vesting and Payout of Units</u>.

As soon as practicable following the Vesting Date for one or more Units (the "Vested Units"), the Company shall cause to be delivered to the Participant: (i) a number of shares of Common Stock (less the number of shares, if any, withheld pursuant to Section 6(b) below) equal to the number of Vested Units in such manner as the Committee may deem appropriate, including book-entry or other electronic registration or issuance of one or more stock certificates and (ii) a lump sum cash payment equal to the amount of dividends that would have been declared, during the period from Grant Date through the Vesting Date(s), on the number of shares of Common Stock being issued under the preceding clause (i) of this Section 3.

4. <u>Participant’s Rights</u>.

The Participant acknowledges and agrees that the Units do not evidence, and do not entitle the Participant to, any rights of a shareholder of the Company.

5. <u>Acceptance of Award</u>.

By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan (a copy of which is attached as Annex I), and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Compensation Committee with respect to any questions arising under the Plan and this Agreement.

6. <u>Taxes and Other Matters</u>.

(a) By execution of this Agreement, the Participant agrees to pay all withholding and other taxes payable with respect to the Units evidenced by this Agreement, at such times and in such manner as the Company may request and to comply with all Federal and State securities laws.

(b) Participant may elect to satisfy Participant's minimum tax withholding requirements upon expiration or lapsing of a Restriction Period, in whole or in part, by having the Company withhold shares of Common Stock having a fair market value equal to all or a portion of the amount so required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable and (ii) made electronically through the Company Stock Plan Services Administrator.

7. <u>Other Condition</u>.

The award of Units evidenced by this Agreement shall be subject to delivery to the Company of an executed copy of this Agreement.

Dated this __________ day of ________________________________.

OGE ENERGY CORP.

BY: ______________________________
Chairman of the Board and
Chief Executive Officer

ACCEPTED AND AGREED TO this __________ day of ________________________________

____
Participant

Exhibit 10.37

OGE ENERGY CORP.
DEFERRED COMPENSATION PLAN

(As Amended and Restated Effective October 1, 2016)

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OGE ENERGY CORP.
DEFERRED COMPENSATION PLAN
(As Amended and Restated Effective October 1, 2016)

I. PURPOSE AND EFFECTIVE DATE

1.1 Purpose. The OGE Energy Corp. Deferred Compensation Plan has been established by OGE Energy Corp. to attract and retain key management employees by providing a tax-deferred capital accumulation vehicle and to supplement such employees' 401(k) contributions, thereby encouraging savings for retirement.

1.2 Effective Date. The following provisions constitute an amendment and restatement of the Plan, effective October 1, 2016. The Plan shall remain in effect until terminated in accordance with Article X.

1.3 Continuation of Prior Plan. The Plan as originally adopted was intended to be an amendment, restatement and continuation of the OGE Energy Corp. Restoration of Retirement Savings Plan (the "Supplemental RSP"). Effective March 27, 2001, the OGE Energy Corp. Directors' Deferred Compensation Plan (formerly known as the Stock Equivalent and Deferred Compensation Plan For Directors of OGE Energy Corp.) (the "Directors' Plan") was merged with and into the Plan.

II. DEFINITIONS

When used in the Plan and initially capitalized, the following words and phrases shall have the meanings indicated:

2.1 "Account" means the recordkeeping account established for each Participant in the Plan for purposes of accounting for the amount of Base Salary, Bonus or Director Compensation deferred under Article IV and Matching and Discretionary Credits, if any, to be credited under Article V, adjusted periodically to reflect assumed investment return on such deferrals, Matching and Discretionary Credits in accordance with Article VI. A Participant's Account may be divided into two or more subaccounts as the Administrator determines necessary or desirable for the administration of the Plan, and shall be divided into the following subaccounts, where applicable: (i) "Pre-2005 Account(s)" to which shall be credited any deferrals, Matching and Discretionary Credits, as adjusted to reflect assumed investment return, that were earned and vested as of December 31, 2004 and (ii) "Post-2004 Account(s)" to which shall be credited any deferrals, Matching and Discretionary Credits, as adjusted to reflect assumed investment return, made for Plan Years beginning before January 1, 2005 but that were not earned and vested as of December 31, 2004 and any deferrals, Matching and Discretionary Credits, as adjusted to reflect assumed investment return, made for Plan Years beginning on or after January 1, 2005.

2.2 “Administrator” means the Plan Administration Committee of the Company or such other individual or committee duly appointed to administer the Plan in accordance with Article IX.

2.3 “Affiliate” means in respect of the Company or other Employer, any corporation, partnership, joint venture, trust, association or other business enterprise which is a member of the same controlled group of corporations or other trades or businesses as the Company or other Employer, as the case may be, within the meaning of Code Section 414(b) or (c); provided, however, that, except for purposes of the term “Affiliate” when used in Section 2.31 below, in applying Code Section 1563(a)(1), (2), and (3) in determining a controlled group of corporations under Code Section 414(b), the language “at least 50 percent” shall be used instead of “at least 80 percent” each place it appears in Code Section 1563(a)(1), (2), and (3), and in applying Treasury Reg. § 1.414(c)-2 for purposes of determining trades or businesses (whether or not incorporated) that are under common control for purposes of Code Section 414(c), “at least 50 percent” shall be used instead of “at least 80 percent” each place it appears in Treasury Reg. § 1.414(c)-2. Notwithstanding the foregoing, any such entity which is an Affiliate of the Company solely because of the proviso in the preceding sentence shall be an Affiliate of the Company for purposes of Section 2.19 or 2.20 only if it has been designated by the Board as an Affiliate whose employees or non-employee directors, as the case may be, are eligible to participate in the Plan.

2.4 “Affiliate Board” means the Board of Directors of any Affiliate.

2.5 “Base Salary” means a Participant’s base salary, prior to any reductions therein, as shown in the personnel records of the Company or applicable Affiliate.

2.6 “Beneficiary” means the person or entity designated by the Participant to receive the Participant’s Plan benefits in the event of the Participant’s death. If the Participant does not designate a Beneficiary, or if the Participant’s designated Beneficiary predeceases the Participant, the Participant’s estate shall be the Beneficiary under the Plan. All Beneficiary designations shall be made in writing in such manner, including electronically, as the Administrator shall prescribe. Any properly completed Beneficiary designation, or changes therein, will be effective on the date it is filed with the Administrator or its delegate during the Participant’s lifetime and, once filed, shall revoke any prior designations.

2.7 “Board” means the Board of Directors of the Company.

2.8 “Bonus” means the annual incentive bonus payable to a Participant under the OGE Energy Corp. Annual Incentive Compensation Plan or any successor thereto or replacement thereof.

2.9 “Change in Control” means the happening of any of the following events:

(a) an acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (“Exchange Act”)) (a “Person”) of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (1) the then outstanding shares of Company Common Stock (the “Outstanding Company Common Stock”) or (2) the combined voting power of the then outstanding voting securities of the Company entitled to vote generally in the election of directors (the “Outstanding Company Voting Securities”); excluding however the following: (1) any acquisition directly from the Company, (2) any acquisition by the Company, (3) any acquisition by any employee benefit plan (or related trust) sponsored by or maintained by the Company or any corporation or other Person controlled by the Company or (4) any acquisition by any corporation or other Person pursuant to a transaction which complies with clauses (1), (2) and (3) of subsection (c) of this Section 2.9; or

(b) a change in the composition of the Board such that the individuals who, as of June 1, 2016, constitute the Board (the “Incumbent Board”) cease for any reason to constitute at least a majority of the Board; provided, however, for purposes of this Section 2.9, that any individual who becomes a member of the Board subsequent to January 1, 2005, whose election or nomination for election by the Company’s shareowners was approved by a vote of at least a majority of those individuals then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board; but provided further, that any such individual whose initial assumption of office occurs as a result of either an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board shall not be so considered as a member of the Incumbent Board; or

(c) consummation of a reorganization, merger, share exchange or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a “Business Combination”), excluding, however, a Business Combination pursuant to which (1) all or substantially all of the individuals and entities who are the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the then outstanding shares of common stock or equity interests and the combined voting power of the then outstanding voting securities entitled to vote generally in the election of directors or other controlling persons, as the case may be, of the corporation or other Person resulting from such Business Combination (including, without limitation, a corporation or other Person which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination, of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (2) no Person (other than the corporation or other Person resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation or other Person resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then outstanding shares of common stock or equity interests of the corporation or other Person resulting from such Business Combination or the combined voting power of the then outstanding voting securities of such corporation or other Person except to the extent that such ownership existed with respect to the Company prior to the Business Combination and (3) at least a majority of the members of the board of directors or other governing body of the corporation or other Person resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or the action of the Board providing for such Business Combination; or

(d) the approval by the shareholders of the Company of a complete liquidation or dissolution of the Company.

2.10 "Code" means the Internal Revenue Code of 1986, as amended.

2.11 "Company" means OGE Energy Corp. and any successor thereto.

2.12 "Company Common Stock" means the common stock, par value $.01 per share, of the Company.

2.13 "Compensation" means Base Salary and/or Bonus with respect to an Eligible Employee and means Director Compensation with respect to an Eligible Director.

2.14 "Deferral Election" means the election made by an Eligible Employee or Eligible Director to defer Compensation in accordance with Article IV.

2.15 "Director Compensation" means the annual cash retainer and cash attendance fees, prior to any reduction therein, payable to an Eligible Director for services as a member of the Board or an Affiliate Board.

2.16 "Disability" (i) as applicable to a Participant's Pre-2005 Account(s), shall have the same meaning as permanent disability under the RSP and (ii) as applicable to a Participant's Post-2004 Account(s), means that the Participant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of not less than 12 months; provided, however, that in either case, the Disability must be incurred prior to the Participant's Separation from Service or termination of service on the Board and Affiliate Boards, as the case may be. A Participant will be treated for purposes of the Plan as incurring a Disability on the date on which the Administrator makes its determination of Disability. A determination of Disability shall be made by the Administrator based upon the written opinion of a licensed physician who has been approved by the Administrator. The decision of the Administrator with respect to a Disability shall be conclusive for all purposes of the Plan.

2.17 "Discretionary Credit" means an amount credited to the Account of a Participant who is an Eligible Director, as determined by the Compensation Committee of the Board in its sole discretion, and shall include, unless otherwise determined by the Compensation Committee of the Board, the portion of the annual retainer fee payable to an Eligible Director in stock equivalent units.

2.18 "Election Period" means the period specified by the Administrator as provided in Article IV during which a Deferral Election may be made with respect to Compensation payable for a Plan Year.

2.19 "Eligible Director" means a member of the Board or an Affiliate Board who, in either case, is not also an employee of the Company or an Affiliate thereof.

2.20 "Eligible Employee" means, unless determined otherwise by the Board, an employee of the Company or of an Affiliate thereof who (i) is an executive or other key employee who is responsible for or contributes to the management, growth and profitability of the Company, as determined by the Administrator and, as determined by the employee's supervisor, is a supervisor or a key contributor, or (ii) was an Eligible Employee under the Plan as in effect prior to January 1, 2003 and had a Deferral Election in effect for the Plan Year beginning January 1, 2002. Notwithstanding the foregoing, an employee shall not be an Eligible Employee if he or she is deemed by the Administrator not to be a member of a select group of management or highly compensated employees of the Company and its Affiliates.

2.21 "Employer" means (i) the Company or (ii) an Affiliate thereof that employed an Eligible Employee or whose board of directors included an Eligible Director while the Eligible Employee or Eligible Director was a Participant and any successor thereto.

2.22 "Matching Credit" means the amount credited to a Participant's Account pursuant to Section 5.1.

2.23 “Participant” means an Eligible Employee or Eligible Director who has elected to defer Compensation or who has been credited with a Discretionary Credit.

2.24 “Partnership Units” means a common unit of Enable Midstream Partners, LP, a Delaware limited partnership, or any successor thereto.

2.25 “Plan” means this OGE Energy Corp. Deferred Compensation Plan, as amended from time to time.

2.26 “Plan Year” means the calendar year.

2.27 “Prior Plan” means the Supplemental RSP or the Directors’ Plan (as defined in Section 1.3), as applicable.

2.28 “Retirement” means a Separation from Service, for reasons other than death, occurring on or after the earlier of (i) the Participant’s attainment of at least age 55 with five (5) or more years of “Vesting Service”, as such term is defined in the OGE Energy Corp. Retirement Plan, as amended from time to time, or any successor thereto or (ii) the Participant’s attainment of age 65.

2.29 “RSP” means the OGE Energy Corp. Employees’ Stock Ownership and Retirement Savings Plan, as amended from time to time.

2.30 “Separation from Service” means in respect of a Participant (other than a Participant who is an Eligible Director), any termination of employment with the Participant’s Employer and its Affiliates due to Retirement, death or any other reason; provided, however, that in respect of a Participant’s Post-2004 Account(s), no Separation from Service for reasons other than death shall be deemed to occur for purposes of the Plan while the Participant is on military leave, sick leave, or other bona fide leave of absence that does not exceed six months or, if longer, the period during which the Participant’s right to reemployment with the Employer or its Affiliates is provided either under applicable statute or by contract; and provided further that, if the period of leave exceeds six months and the Participant does not retain a right to reemployment under an applicable statute or by contract, a Separation from Service will be deemed to have occurred on the first day following such six-month period. Whether and when a Separation of Service has occurred for purposes of the Plan in respect of a Participant’s Post-2004 Accounts shall be determined based on the meaning of “separation from service” under Code Section 409A and the regulations promulgated thereunder and, accordingly, shall be based on whether the facts and circumstances indicate that the Employer and its Affiliates and the Participant reasonably anticipate that no further services will be performed after a certain date or that the level of bona fide services the Participant will perform after such date (whether as an employee or as an independent contractor) will permanently decrease to no more than 20% of the average level of bona fide services performed (whether as an employee or independent contractor) over the immediately preceding 36-month period (or the full period of services to Employer and its Affiliates if the Participant has been providing services to the Employer and its Affiliates less than 36 months). A Participant shall be presumed for this purpose to have a Separation from Service where the level of bona fide services decreases to a level equal to 20% or less of such average level of services.

2.31 <u>“Specified Employee”</u> means, during the 12-month period beginning on April 1st of 2005 or of any subsequent calendar year, an employee or director of the Participant’s Employer or its Affiliates who met the requirements of Section 416(i)(1)(A)(i), (ii) or (iii) of the Code (applied in accordance with the regulations thereunder and without regard to Code Section 416(i)(5)) for being a “key employee” at any time during the 12-month period ending on the December 31st immediately preceding such April 1st. Notwithstanding the foregoing, a Participant who otherwise would be a Specified Employee under the preceding sentence shall not be a Specified Employee for the purposes of the Plan unless, as of the date of the Participant’s Separation from Service or termination of service on the Board and Affiliate Boards, as the case may be, stock of such Employer or an Affiliate thereof is publicly traded on an established securities market or otherwise.

2.32 <u>“Supplemental RSP”</u> has the meaning ascribed to such term in Section 1.3.

2.33 <u>“Valuation Date”</u> means the last business day of each calendar month and such other dates as may be specified by the Administrator; provided, however, that for purpose of Article VI (other than Section 6.4) only, Valuation Date shall mean each day the New York Stock Exchange is open.

III. PARTICIPATION

An Eligible Employee or Eligible Director shall become a Participant in the Plan by filing a Deferral Election with the Administrator in accordance with Article IV. In addition, an Eligible Director who is not otherwise a Participant in the Plan shall become a Participant in the Plan on the date he or she is credited with a Discretionary Credit. If the Administrator determines that participation by one or more Participants shall cause the Plan to be subject to Part 2, 3 or 4 of Title I of the Employee Retirement Income Security Act of 1974, as amended (“ERISA”), the entire interest of such Participant or Participants under the Plan shall be segregated from the Plan and held under a mirror plan with identical terms for the benefit of the Participant, and such Participant or Participants shall cease to have any interest under the Plan. Subject to the preceding sentence, if a Participant ceases for any Plan Year to be an Eligible Employee or Eligible Director, as the case may be, but remains or becomes an employee or member of the Board of Directors of the Company or an Affiliate, (i) the Participant’s Deferral Election shall continue in effect for the remainder of the Plan Year (or until payment of his Account balance under Section 7.2 or 7.3, if earlier) as if he had remained an Eligible Employee or

Eligible Director but the Participant shall be unable to defer Compensation under Article IV for any subsequent Plan Year until the Participant should again become an Eligible Employee or Eligible Director and becomes a Participant by filing a Deferral Election in accordance with Article IV, (ii) the Participant shall no longer be able to receive Matching and Discretionary Credits, if any, under Article V for such Plan Year or for any subsequent Plan Year until the Participant should again become an Eligible Employee or Eligible Director, and (iii) such Participant's Account shall continue to be subject to all the terms and conditions of the Plan, including Sections 5.3 and 5.4 and Articles VI, VII and VIII, as if such Participant had remained an Eligible Employee or Eligible Director.

IV. DEFERRAL OF COMPENSATION

4.1 Deferral of Base Salary. An Eligible Employee may elect to defer up to 70% of his or her Base Salary for a Plan Year by filing a Deferral Election in accordance with Section 4.4.

4.2 Deferral of Bonus. An Eligible Employee may elect to defer up to 100% of his or her Bonus for a Plan Year by filing a Deferral Election in accordance with Section 4.4.

4.3 Deferral of Director Compensation. An Eligible Director may elect to defer up to 100% of his or her Director Compensation for a Plan Year by filing a Deferral Election in accordance with Section 4.4.

4.4 Deferral Elections. A Participant's Deferral Election shall be in writing, and shall be filed with the Administrator at such time and in such manner, including electronically, as the Administrator shall provide, subject to the following:

(a) A Deferral Election shall be made during the Election Period established by the Administrator which, in the case of Base Salary and Director Compensation, shall end no later than the day preceding the first day of the Plan Year in which the services in respect of which such Base Salary or Director Compensation would otherwise be payable are performed and, in the case of Bonus, shall end no later than the last day of the Plan Year preceding the Plan Year to which such Bonus relates. For purposes of the Plan, a bonus relates to the Plan Year with respect to which the services entitling the Participant to the bonus are performed regardless of whether the bonus is payable in that or any later year.

(b) Deferral Elections may be expressed as a percentage or fixed dollar amount of Base Salary, Bonus, or Director Compensation, as applicable, within the limits provided under the Plan.

(c) In lieu of a Deferral Election under Section 4.1 or 4.2, the Participant may elect with respect to a Plan Year that deferrals of Base Salary and Bonus be made to the Plan starting when the Participant has made the maximum deferrals permitted for the Plan Year under the RSP because of limitations on such deferrals contained in the Code. Any such election will be based on a joint deferral percentage elected for that Plan Year under both the RSP and this Plan during the Election Period ending no later than the last day immediately preceding that Plan Year and may not be revoked or changed under this Plan during the Plan Year. If, notwithstanding the foregoing, the Participant should change his or her deferral election under the RSP during such Plan Year, deferrals will continue to be made under this Plan for the remainder of the Plan Year as if the RSP deferral election had remained unchanged. Notwithstanding the foregoing, (i) any such election under the RSP and this Plan applied to a Plan Year in which a Bonus is payable shall be applied independently of and separately from any election made previously under Section 4.2 with respect to the same Bonus, and (ii) if, at the time all or any portion of a Bonus is payable, the maximum deferrals permitted under the RSP for the Plan Year have been made due to the limitations on such deferrals contained in the Code, the election, if any, made under this Section 4.4(c) for the Plan Year to which the Bonus relates (as provided in Section 4.4(a)) shall apply under the Plan (and not the election made under this Section 4.4(c) for the Plan Year in which the Bonus is payable) to that portion of the Bonus that cannot be taken into account in making deferrals under the RSP for such Plan Year because of the Code limitations on deferrals.

(d) Notwithstanding the foregoing provisions of this Section 4.4, the Administrator may provide that an individual who becomes an Eligible Employee on his date of hire by the Company and its Affiliates that occurs on or after the first day and prior to December 1 of a Plan Year may make a Deferral Election for such Plan Year within 30 days of becoming an Eligible Employee; provided, however, that such Deferral Election shall relate only to (i) Base Salary paid for the services to be performed after the date such election becomes irrevocable; and/or (ii) the portion of the Bonus relating to the services performed after the election becomes irrevocable, determined by multiplying the total Bonus amount relating to the Plan Year by a ratio of the number of days remaining in such Plan Year after the Deferral Election becomes irrevocable to the total number of days in the Plan Year. Notwithstanding the foregoing, no individual who becomes an Eligible Employee on his date of hire by the Company and its Affiliates that occurs on or after the first day and prior to December 1 of a Plan Year as a result of or in connection with a corporate acquisition, merger or similar transaction shall be eligible to make a Deferral Election under this subsection (d) unless the Administrator determines, consistent with the provisions of Treas. Reg. Section 1.409A-2(a)(7), that the Eligible Employee is not already a participant or eligible to participate in any other nonqualified deferred compensation plan that would be aggregated with the Plan pursuant to Code Section 409A.

(e) Notwithstanding the foregoing provisions of this Section 4.4, the Administrator may provide that an individual who becomes an Eligible Director after the first day of a Plan Year may make a Deferral Election within 30 days of becoming an Eligible Director, which Deferral Election shall relate to Director Compensation paid for services to be performed after the date such election becomes irrevocable.

(f) Once made, a Deferral Election for a Plan Year shall become irrevocable at the end of the Plan Year in which occurs the Election Period during which the Deferral Election was made (or, where applicable, on the last day of the 30-day period described in subsection (d) or (e) above, as the case may be), but such Deferral Election may be changed or revoked prior to the time that the election becomes irrevocable in accordance with rules established by the Administrator. A Deferral Election which has become irrevocable shall remain in effect for the Plan Year for which made and for subsequent Plan Years unless changed or revoked by the Participant in accordance with rules established by the Administrator. Any such modification or revocation, however, shall be effective beginning for the Plan Year following the Plan Year in which the modification or revocation is filed with the Administrator; provided that, a revocation shall become effective as soon as practicable during the Plan Year in which filed with the Administrator in the event the revocation is required because the Participant obtained a hardship withdrawal under the RSP. If a Deferral Election is revoked during a Plan Year in accordance with the preceding sentence in order for the Participant to obtain a hardship withdrawal under the RSP, the Participant may not make a new Deferral Election before the Election Period established by the Administrator for making deferrals to be effective for the next Plan Year. As of the last day of each Plan Year, a Deferral Election then in effect, shall become irrevocable for the immediately following Plan Year except to the extent modified or revoked as provided above.

4.5 Crediting of Deferral Elections. The amount of Compensation that a Participant elects to defer under the Plan shall be credited by the Company to the Participant's Account as of the date on which the Compensation would have been payable absent the Deferral Election. The amounts so credited shall be deemed invested in the assumed investment alternatives available under the Plan as provided in Article VI.

V. EMPLOYER CREDITS

5.1 Matching Credits. A Participant (other than a Participant who is an Eligible Director) who has made a Deferral Election for a Plan Year shall be credited with a “Matching Credit” for the Plan Year equal to the excess of (i) the matching contribution that would have been made under the RSP for such Plan Year if the first 6% of the Participant’s Base Salary and Bonus otherwise payable in such Plan Year that is deferred under this Plan and the RSP (other than as “Catch-up Contributions” thereunder) were treated as “Tax-Deferred Contributions” under the RSP, without regard to any limitations on such matching contributions contained in the RSP due to the application of Sections 401(a)(17), 401(k)(3), 401(m), 402(g) or 415 of the Code, over (ii) the greater for such Plan Year of (A) the maximum amount of matching contributions the Participant is eligible to receive under the RSP with respect to Tax Deferred Contributions (determined by taking into account the provisions of the RSP), or (B) the actual matching contributions received under the RSP with respect to all contributions. Such Matching Credit shall be credited to the Participant’s Account at the same time that the underlying Base Salary or Bonus deferral is credited to the Participant’s Account. The amounts so credited shall be deemed invested in the assumed investment alternatives available under the Plan to the Participant as provided in Article VI. Notwithstanding the foregoing, if after the beginning of a Plan Year a Participant changes in any way his or her Tax-Deferred Contributions, Roth Contributions and/or After-Tax Contribution elections under the RSP in a manner that would affect the amount of Matching Credits to be made under the Plan for such Plan Year, the Matching Credits to be credited to the Participant’s Account for such Plan Year shall be appropriately reduced or increased, as the case may be, provided that the aggregate Matching Credits under the Plan for such Plan Year do not exceed 100% of the matching contributions that would be provided under the RSP absent any plan-based restrictions that reflect limits on contributions under the Code.

5.2 Discretionary Credits. The Compensation Committee of the Board may award a Participant who is an Eligible Director a Discretionary Credit at such time and in such amount determined by that Committee in its sole discretion. Any such Discretionary Credit shall be credited to the Participant’s Account at the time determined in writing by the Compensation Committee of the Board at the time of the award. Unless otherwise determined by the Compensation Committee of the Board, each Discretionary Credit shall be deemed invested under the Plan initially in Company Common Stock.

5.3 Vesting. Matching Credits credited to a Participant’s Account on or after January 1, 2012, as adjusted for assumed investment return, shall vest based on the Participant’s years of service (which shall be equal to the Participant’s “Years of Vesting Service” within the meaning of and as credited to the Participant under the RSP) under the following schedule:

Years of Service	Percentage of Matching Credits Vested
Less than 3	0%
3 or more	100%

With respect to any Participant who is employed by the Company or Affiliates on or after January 1, 2002, the Participant's vested percentage of the Participant's Matching Credits credited before January 1, 2012, as adjusted for assumed investment return, shall be determined in accordance with the following schedule:

Years of Service	Percentage of Matching Credits Vested
Less than 2	0%
2 but less than 3	20%
3 but less than 4	40%
4 but less than 5	60%
5 but less than 6	80%
6 or more	100%

A Participant's Discretionary Credit, if any, shall be 100% vested upon award unless provided otherwise in the terms established in writing by the Compensation Committee of the Board at the time it is awarded. Subject to Section 5.4, any portion of a Participant's Account that is not vested upon the Participant's Separation from Service or termination of service on the Board and Affiliate Boards, as the case may be, shall be permanently forfeited.

5.4 Acceleration of Vesting. Notwithstanding the provisions of Section 5.3, a Participant's Matching Credits and Discretionary Credits, if any, as adjusted for assumed investment return, shall become fully vested upon the following events:

(a) the Participant's Retirement (other than in respect of a Participant who is an Eligible Director);

(b) the Participant's Disability;

(c) the Participant's death;

(d) a Change in Control; or

(e) Termination of the entire Plan under Article X.

VI. PLAN ACCOUNTS

6.1 Valuation of Accounts. The Administrator has established or shall establish an Account for each Participant who has filed a Deferral Election to defer Compensation or who has been awarded a Discretionary Credit, or who had an account with respect to the Prior Plans as of January 1, 2005. Such Account and applicable subaccounts shall be credited with a Participant's deferrals, Matching Credits and Discretionary Credits as set forth in Sections 4.5, 5.1 and 5.2, respectively, and with the Participant's Prior Plan account balance, if any. Amounts credited to a Participant's Account and applicable subaccounts as set forth in Sections 4.5, 5.1 and 5.2 shall be deemed invested in the applicable assumed investment alternatives subject to the provisions of Section 6.2 and 6.3, as of the Valuation Date credited to the Account based on the fair market value of such investment as of such date. As of each Valuation Date, the Participant's Account and applicable subaccounts thereunder shall be adjusted upward or downward to reflect (i) the investment return to be credited as of such Valuation Date pursuant to Section 6.2, (ii) the amount of distributions, if any, debited since the next preceding Valuation Date under Article VII or Article VIII, and (iii) the amount of forfeitures or reductions, if any, debited since the next preceding Valuation Date under Sections 5.1, 5.3 or 7.4.

6.2 Crediting of Investment Return. Subject to such rules and limitations as the Administrator may determine and the provisions of Section 5.2 and this Section 6.2, each Participant shall designate from among the available assumed investment alternatives established by the Administrator under Section 6.3, one or more assumed investments in which the amounts credited to his or her Account shall be deemed invested. As of each Valuation Date, a Participant's Account balance and subaccounts thereunder shall be adjusted upward or downward for increases and decreases in the fair market value of, and for interest, dividends or other distributions paid on, the investments in which deemed invested during the period since the immediately preceding Valuation Date, net of any allocable expenses of the Plan and related trusts that the Company does not elect to pay. On each Valuation Date or other such time as the Administrator or its delegate shall provide from time to time, a Participant may make a new election, to be effective immediately after the close of business on such Valuation Date, with respect to the assumed investments in which his or her Account shall be deemed invested in the future (including the portion of any Eligible Director's Account attributable to Discretionary Credits that is deemed invested in Company Common Stock or, if the Compensation Committee of the Board has so determined, Partnership Units). Such new election may (i) redirect the investment of his or her ending Account balance as of the close of business on such last business day or Valuation Date, as the case may be, among the available assumed investment alternatives and/or (ii) change the assumed investment alternatives in which future contribution credits to be made as of or after the effective date of the election will be deemed invested (other than future Discretionary Credits, unless

the Compensation Committee specifically directs that Discretionary Credits are not required to be deemed invested in Company Common Stock or Partnership Units). Any such election shall be made in the form and at the time specified by the Administrator, including electronically. The portion of a Participant's Account that is deemed invested in Company Common Stock or Partnership Units, if any, shall also be credited with deemed dividends or other distributions as of the date on which dividends or other distributions on Company Common Stock or Partnership Units are paid, and such deemed dividends or other distributions shall be deemed reinvested in Company Common Stock or Partnership Units, as the case may be, based on the fair market value thereof as provided in Section 6.3.
Participants who are subject to the reporting requirements of Section 16 of the Securities Exchange Act of 1934 may be subject to election restrictions with respect to the assumed investment alternative based on Company Common Stock or Partnership Units, including a restriction that such election will not take effect until approved by the Secretary of the Company.

6.3 Assumed Investment Alternatives. The Administrator shall designate the assumed investment alternatives that will be available from time to time under the Plan for purposes of measuring a Participant's investment return under Section 6.2. Such assumed investment alternatives shall include an assumed investment in Company Common Stock and may include in respect of some or all Participants, an assumed investment in Partnership Units. Amounts credited to a Participant's Account and applicable subaccounts as set forth in Sections 4.5, 5.1 and 5.2 and dividends or other distributions on Company Common Stock or Partnership Units under Section 6.2 that are deemed invested in Company Common Stock or Partnership Units shall be deemed so invested based on the fair market value of a share of Company Common Stock or Partnership Unit, as the case may be, as reported on the New York Stock Exchange composite tape at the close of business on the Valuation Date on or next preceding the date on which the amount is being deemed so invested. Notwithstanding the foregoing, any assumed investment alternative made available under the Plan must qualify as a predetermined actual investment within the meaning of Treasury Reg. § 31.3121(v)(2)-1(d)(2) or for any Plan Year reflect a reasonable rate of interest (determined in accordance with Treasury Reg. § 31.3121(v)(2)-1(d)(2)(i)(C)).

6.4 Investment Alternatives After Death. For periods after the Valuation Date coincident with or next following a Participant's death, the Participant's Account balance shall be treated as if it were invested in a fixed interest rate account at prevailing short-term interest rates, as determined by the Administrator. Beneficiaries shall not be permitted to make elections with respect to assumed investment alternatives under the Plan.

VII. PAYMENT OF BENEFITS

7.1 Distribution at Specified Future Date.

(a) Elections by Eligible Employees.

(i) Initial Election. With respect to an Eligible Employee’s first Plan Year of participation, at the time the Eligible Employee initially elects to participate in the Plan or, if earlier, by 30 days after the date he or she becomes an Eligible Employee, the Eligible Employee may elect one or more specified future Valuation Dates on which and one or more forms of distribution set forth in paragraph (e) below under which all or a portion of the Compensation deferred pursuant to the applicable Deferral Election, as adjusted for assumed investment return, shall be paid or commence to be paid.

(ii) Subsequent Election. With respect to Plan Years subsequent to an Eligible Employee’s initial Plan Year of participation, during the Election Period for any such Plan Year, the Eligible Employee may elect one or more specified future Valuation Dates on which and one or more forms of distribution set forth in paragraph (e) below under which all or a portion of the Compensation deferred pursuant to the applicable Deferral Election, as adjusted for assumed investment return, shall be paid or commence to be paid.

(b) Elections by Eligible Directors

(i) Initial Election. With respect to an Eligible Director’s first Plan Year of participation, at the time the Eligible Director initially elects to participate in the Plan or, if earlier, by the last to occur of (A) 30 days after the date he or she becomes an Eligible Director or (B) the last day of the calendar year ending immediately prior to the calendar year in which he or she performs services for which a Discretionary Credit under the Plan is first made for the Participant, the Eligible Director may elect one or more specified future Valuation Dates on which and one or more forms of distribution set forth in paragraph (e) below under which all or a portion of the Compensation deferred pursuant to the applicable Deferral Election (or, in the case of an election with respect to Discretionary Credits, all or a portion of his Discretionary Credits credited in the Plan Year to which such election relates), as adjusted for assumed investment return, shall be paid or commence to be paid.

(ii) Subsequent Election. With respect to Plan Years subsequent to an Eligible Director's initial Plan Year of participation, during the Election Period for any such Plan Year, the Participant may elect one or more specified future Valuation Dates on which and one or more forms of distribution set forth in paragraph (e) below under which all or a portion of the Compensation deferred pursuant to the applicable Deferral Election (or, in the case of an election with respect to Discretionary Credits, all or a portion of his Discretionary Credits credited in the Plan Year to which such election relates), as adjusted for assumed investment return, shall be paid or commence to be paid.

(c) Limits on Distribution Elections.

(i) Notwithstanding any other provision of the Plan, a Participant may have no more than five specified date distribution elections in place under this Section 7.1 at one time under the Plan. However, for the avoidance of doubt, once a Participant has in place one or more specified date elections under this Section 7.1, the Participant may elect, during the Election Period for any Plan Year, that all or a portion of the Compensation deferred pursuant to the applicable Deferral Election for the Plan Year (or, in the case of an election with respect to Discretionary Credits, all or a portion of his Discretionary Credits credited in the Plan Year to which such election relates), as adjusted for assumed investment return, be distributed to the Participant pursuant to any such election.

(ii) Distribution at a specified future date under this Section 7.1 is not permitted for Matching Credits.

(d) Permissible Election Dates. Any specified future date elected in an election under this Section 7.1 shall be a Valuation Date in a specified future year which is at least two Plan Years after the Plan Year for which the initial election is made.

(e) Form of Distribution. Distribution under this Section 7.1 pursuant to any election shall be made:

(i) in a lump sum in an amount equal to the balance in the portion of the Account to be paid in a lump sum determined as of the Valuation Date coincident with or next preceding the date of payment, or

(ii) in annual installments of up to 5 years as designated in the Participant's election, with the first such installment payment to be made as of the date designated in paragraph (d) above and the additional payments to be made on the next four (or such lesser number elected by the Participant) anniversaries thereof (and, for purposes of Section 409A of the Code, each such installment payment shall be one of a series of payments treated as a single payment).

The amount of each installment payment to be made to a Participant under clause (ii) above shall be equal to the quotient obtained by dividing the balance in the portion of his or her Account subject to the election as of the Valuation Date coincident with or next preceding the date of such installment payment by the number of installment payments remaining to be made to the Participant at the time of such calculation.

If the Participant does not make a valid distribution election in accordance with the foregoing provisions of this Section 7.1 with respect to all or any portion of the Participant's Account, the Participant's Account (or such portion thereof) shall be paid in a lump sum.

(f) Revocation/Modification of Distribution Election.

(i) Pre-2005 Accounts. A distribution election under this Section 7.1 applicable to a Participant's Pre-2005 Account may be revoked or extended to a Valuation Date in a future Plan Year by filing a revocation or extension election with the Administrator at least 12 months prior to the first day of the Plan Year in which such distribution was scheduled to take place; provided, however, that only one such subsequent change shall be permitted with respect to any distribution election.

(ii) Post-2004 Accounts. A distribution election under this Section 7.1 applicable to a Participant's Post-2004 Account may be modified as to form or timing of payment by filing a new election with the Administrator at least 12 months prior to the previously-designated Valuation Date on which such distribution was scheduled to take place; provided, however, that the election must provide a new Valuation Date that is at least five years subsequent to the previously-designated Valuation Date. Such election will become irrevocable upon receipt by the Administrator and will not be given effect until 12 months after it is filed with the Administrator.

(g) Early Disability or Termination. If the Participant elects pursuant to this Section 7.1 a distribution at or to commence at one or more specified future Valuation Dates and incurs a Disability or a Separation from Service or termination of service on the Board and Affiliate Boards, as the case may be, prior to any such selected Valuation Date, such election shall be without further effect and distribution shall commence pursuant to Section 7.2, 7.3, 8.1 or 8.2, as applicable.

7.2 Distribution Upon Retirement or Disability; Termination of Board Service.

(a) Elections by Eligible Employees. Subject to Section 7.8 relating to distributions to Specified Employees, if a Participant who is an Eligible Employee incurs a Disability or a Separation from Service by reason of Retirement, distribution of the Participant's Account (or in the case of Disability, the portion(s) of the Account with respect to which the Participant has incurred a Disability) shall be made or commence, but subject to Section 11.7, as of one of the dates set forth in paragraph (c) and in one of the forms set forth in paragraph (d) below and elected by the Participant in his or her Deferral Election made at the time the Participant initially elects to participate in the Plan or, if earlier, by 30 days after the date he or she becomes an Eligible Employee, provided that this Section 7.2(a) shall not apply with respect to the portion (if any) of such Eligible Employee's Account that has commenced to be distributed to the Participant in installments pursuant to Section 7.1.

(b) Elections by Eligible Directors.

(i) Initial Election. Subject to Section 7.8 relating to distributions to Specified Employees and Section 11.7, with respect to an Eligible Director's first Plan Year of participation, at the time the Eligible Director initially elects to participate in the Plan or, if earlier, by the last to occur of (i) 30 days after the date he or she becomes an Eligible Director, as the case may be or (ii) the last day of the calendar year ending immediately prior to the calendar year in which he or she performs services for which a Discretionary Credit under the Plan is first made for the Participant, the Eligible Director may elect one or more of the dates set forth in paragraph (c) below and one or more of the forms set forth in paragraph (d) below for distribution of all or a portion of the Compensation deferred pursuant to the applicable Deferral Election (or, in the case of an election with respect to Discretionary Credits, all or a portion of his Discretionary Credits credited in the Plan Year to which such election relates), as adjusted for assumed investment return, to be made or commence in the event the Participant incurs a Disability or terminates service on the Board and Affiliate Boards; provided that in the case of Disability, only the portion(s) of the Account with respect to which the Participant has incurred a Disability shall be distributed hereunder.

(ii) Subsequent Election. Subject to Section 7.8 relating to distributions to Specified Employees and Section 11.7, with respect to Plan Years subsequent to an Eligible Director's initial Plan Year of participation, during the Election Period for any such Plan Year, the Eligible Director may elect a date set forth in paragraph (c) below and a form set forth in paragraph (d) below for distribution of all or a portion of the Compensation deferred pursuant to the applicable Deferral Election (or, in the case of an election with respect to Discretionary Credits, all or a portion of his Discretionary Credits credited in the Plan Year to which such election relates), as adjusted for assumed investment return, to be made or commence in the event the Participant incurs a Disability or terminates service on the Board and Affiliate Boards; provided that in the case of Disability, only the portion(s) of the Account with respect to which the Participant has incurred a Disability shall be distributed hereunder.

(iii) Limitations.

(A) Notwithstanding any other provision of the Plan, an Eligible Director may have no more than two time and form of payment elections in place under this Section 7.2(b). However, for the avoidance of doubt, once an Eligible Director has in place one or two time and form of payment elections under this Section 7.2(b), the Eligible Director may elect, during the Election Period for any Plan Year, that all or a portion of the Compensation deferred pursuant to the applicable Deferral Election for the Plan Year (or, in the case of an election with respect to Discretionary Credits, all or a portion of his Discretionary Credits credited in the Plan Year to which such election relates), as adjusted for assumed investment return, be distributed to the Eligible Director pursuant to either such election.

(B) The provisions of this Section 7.2(b) shall not apply with respect to the portion (if any) of such Eligible Director's Account that has commenced to be distributed to the Participant in installments pursuant to Section 7.1.

(iv) Coordination with Section 7.1(d). If an Eligible Director has elected a distribution at or to commence at one or more specified future Valuation Dates pursuant to Section 7.1(b) and incurs a Disability or termination of service on the Board and Affiliate Boards (other than by reason of death) prior to any such selected Valuation Date, such election is without further effect pursuant to Section 7.1(d) and distribution shall commence pursuant to the time and form of payment applicable under Section 7.2(b)(i) (provided that if an Eligible Director has two time and form of payment elections in place under Section 7.2(b)(i), distribution shall be made pursuant to his “Retirement/Termination Account”).

(c) Permissible Election Dates. Distribution under this Section 7.2 pursuant to any election shall be made or commence on one of the following dates:

(i) the Valuation Date coincident with or next following the date the Participant incurs a Disability or a Separation from Service or termination of Board and Affiliate Board service, as applicable; or

(ii) January 1st of the Plan Year immediately following the Plan Year in which the Participant incurs a Disability or a Separation from Service or termination of Board and Affiliate Board service, as applicable.

(d) Form of Distribution. Distribution under this Section 7.2 pursuant to any election shall be made:

(i) in a lump sum in an amount equal to the balance in the portion of the Account to be paid in a lump sum determined as of the Valuation Date coincident with or next preceding the date of payment,

(ii) in annual installments of up to 15 years as designated in the Participant’s election, with such installments to be made as of the date designated above and anniversaries thereof (and, for purposes of Section 409A of the Code, each such installment payment shall be a separate payment and not one of a series of payments treated as a single payment), or

(iii) in a combination of (i) and (ii), as elected by the Participant in his or her election(s).

The amount of each installment payment to be made to a Participant under clause (ii) above shall be equal to the quotient obtained by dividing the balance in the portion of his or her Account subject to the election as of the Valuation Date coincident with or next preceding the date of such installment payment by the number of installment payments remaining to be made to the Participant at the time of such calculation.

(e) Default Time and Form of Payment. If a Participant does not make a valid distribution election, in accordance with the foregoing provisions of this Section 7.2, with respect to all or any portion of the Participant’s Account that is subject to this Section 7.2, the Participant’s Account (or such portion thereof) shall be paid in a lump sum on the Valuation Date coincident with or next following the date the Participant incurs a Disability, Separation from Service or termination of Board and Affiliate Board service, as applicable.

(f) Revocation/Modification of Distribution Election.

(i) Pre-2005 Accounts. A Participant may change the time and form of his or her distribution election under this Section 7.2 applicable to his or her Pre-2005 Account balance by filing a new election with the Administrator; provided, however, that any election change that has not been on file with the Administrator at least 12 months prior to the first day of the Plan Year in which the Participant's Disability, Separation from Service or termination of service on the Board and Affiliate Boards, as the case may be, occurs shall be void and disregarded. Notwithstanding the foregoing, a Participant who incurs a Disability may request that the Administrator distribute the Participant's Pre-2005 Account balance in a lump sum payment following the occurrence of such Disability in which case the Administrator, in its sole discretion, shall determine whether to make payment in a lump sum.

(ii) Post-2004 Accounts. A Participant may change the time and form of his or her distribution election under this Section 7.2 applicable to his or her Post-2004 Account balance by filing a new election with the Administrator; provided, however, that any such election will not be given effect until the date that is 12 months after the date the election was filed and provided, further, that the time of distribution shall (except with respect to payments due to Disability) be no sooner than the fifth (5^{th}) anniversary of the date distribution was previously scheduled to commence.

(iii) Any change election under this paragraph shall become irrevocable upon receipt by the Administrator.

7.3 Distribution On Other Termination of Employment. Subject to Section 7.8 relating to distributions to Specified Employees, if a Participant's Separation from Service occurs for any reason other than Retirement or death and the Participant has not incurred a Disability prior thereto, the Participant's Account (or the portion thereof with respect to which the Participant has incurred such a termination) shall be paid in a lump sum payment, but subject to Section 11.7, as of the Valuation Date coincident with or next following such Separation from Service. Notwithstanding the foregoing, the Administrator, in its sole discretion, may elect to distribute the Participant's Pre-2005 Account under this Section 7.3 in up to five substantially equal annual payments commencing as of the Valuation

Date coincident with or next following the Participant's Separation from Service. This Section 7.3 shall not apply to a Participant who is an Eligible Director.

7.4 Unscheduled Withdrawal of Pre-2005 Accounts. A Participant may request a withdrawal of all or a portion of his or her Pre-2005 Account by filing an election with the Administrator specifying the amount of the Pre-2005 Account to be withdrawn. Payment of such amount, adjusted by the amount forfeited as provided in the following sentence, shall be made as of the first Valuation Date administratively practicable after such request is received. An amount equal to 10% of the withdrawal requested shall be debited to the Participant's Account and permanently forfeited at the time the withdrawal is made.

7.5 Withdrawal on Unforeseeable Emergency. Prior to the date otherwise scheduled for payment under the Plan, upon showing of an unforeseeable emergency, a Participant who has not incurred a Disability, Separation from Service or terminated service on the Board and Affiliate Boards, as the case may be, may request that the Administrator accelerate payment of all or a portion of his or her vested Account in an amount not exceeding the amount necessary to meet the unforeseeable emergency (including amounts needed to pay any taxes that are reasonably anticipated as a result of the withdrawal). With respect to a Participant's Pre-2005 Account, an unforeseeable emergency means an unanticipated emergency that is caused by an event beyond the control of the Participant and that would result in severe financial hardship to the Participant if early withdrawal were not permitted. With respect to a Participant's Post-2004 Account, an unforeseeable emergency means an unforeseeable emergency as defined in Treasury Regulation Section 1.409A-3(i)(3). The determination of an unforeseeable emergency shall be made by the Administrator in its sole discretion, based on such information as the Administrator shall deem to be necessary and, with respect to a Participant's Post-2004 Account, shall be made and administered in accordance with the rules set forth in Treasury Regulation Section 1.409A-3(i)(3).

7.6 Form of Elections. All distribution and withdrawal elections under this Article VII shall be made in the form established by the Administrator.

7.7 Form of Payment; Withholding. All payments under the Plan shall be made in cash and are subject to the withholding of all applicable taxes.

7.8 Delay In Payment to Specified Employees. Notwithstanding the foregoing provisions of this Article VII, if a Participant is a Specified Employee at the time of his or her Separation from Service or termination of service on the Board and Affiliate Boards, as the case may be, for reasons other than death and is to receive as a result of such Separation from Service or termination of service a distribution from his or her Post-2004 Account under Section 7.2 or 7.3 before the date that is six months after the date of such Separation from Service or termination of service on the Board and Affiliate Boards, no distribution from the Participant's Post-2004 Account shall be made to or in respect of the Participant under section 7.2 or 7.3 of the Plan until the end of such six-month period (or until the Participant's death, if earlier). Any such distribution to which the Participant is otherwise entitled to receive during such six-month period shall instead be paid as of the first day of the seventh month following the date of Separation from Service or termination of service on the Board and Affiliate Boards or, in the event of the Participant's earlier death, as provided in Article VIII. Until paid, any amount otherwise distributable from the Participant's Post-2004 Account prior to the end of such six-month period (or the Participant's death, if earlier) shall continue to be adjusted under Article VI to reflect investment returns of the investments in which the Participant's Post-2004 Account is deemed invested, and the amount distributable shall be valued as of the Valuation Date coincident with or next preceding the date payment is made. Further, any installment payments to be made under Section 7.2 from the Post-2004 Account of a Participant to whom this Section 7.8 is applicable shall be made on the applicable anniversaries of the distribution date determined under this Section 7.8.

7.9 Termination of Service on Board or Affiliate Board. For purposes of the Plan, a Participant who is an Eligible Director shall be deemed to terminate service on the Board or an Affiliate Board only when the Participant is considered to have a "separation from service", within the meaning of Section 409A of the Code, with the Company and its Affiliates.

VIII. DEATH BENEFITS

8.1 Death Prior to Termination.

(a) Participants other than Eligible Directors. If a Participant, other than an Eligible Director, incurs a Separation from Service by reason of death and had not incurred a Disability prior thereto, the Participant's Beneficiary shall receive a survivor benefit in an amount equal to the sum of:

(i) the Participant's Account balance,

plus

(ii) the Participant's total Base Salary and Bonus deferrals deferred under the Plan and the Prior Plans, multiplied by two.

(b) Eligible Directors. If a Participant who is an Eligible Director dies prior to termination of his or her service on the Board and Affiliate Boards and prior to incurring a Disability, the Participant's Beneficiary shall receive a survivor benefit in an amount equal to the sum of:

(i) the Participant’s Account balance,

plus

(ii) the Participant’s total Director Compensation deferrals deferred under the Plan and the Prior Plans for periods on or after January 1, 2000, multiplied by two.

Such survivor benefits shall be paid in a single lump sum, but subject to Section 11.7, as of the Valuation Date coincident with or next following the date of Participant’s death.

8.2 Death After Termination. Subject to Section 8.3, if (i) a Participant incurs a Disability or (ii) prior to incurring a Disability a Participant’s Separation from Service for reasons other than death occurs or, in the case of an Eligible Director, the Participant terminates service on the Board and Affiliate Boards, and thereafter the Participant dies prior to the time his or her vested Account balance has been fully distributed, the Participant’s Beneficiary shall receive any remaining portion of the Participant’s vested Account at the regularly-scheduled date of payment of the Account balance or for the remaining installment payments of the Participant’s Account, as the case may be.

8.3 Post-Retirement Survivor Benefit. If a Participant has a Separation from Service by reason of Retirement and thereafter dies with an Eligible Spouse (defined below) surviving, then in addition to the remaining installments or Account balance payable to the Participant’s Beneficiary under Section 8.2, if any, the Participant’s Eligible Spouse shall be entitled to a “Supplemental Retirement Benefit.” The Supplemental Retirement Benefit shall be payable in the form of an annual annuity for the life of the Eligible Spouse, with such annuity to commence as provided in the following paragraph. The amount of the annuity shall be the amount that would be payable if 50% of the Participant’s Account balance as of the Valuation Date coincident with or next following the Participant’s Retirement had been used to purchase an annual annuity for the life of the Eligible Spouse, determined using interest and actuarial factors established by the Administrator, commencing as of the first day of the month following the month in which Retirement occurs. For purposes of this Section 8.3, the term “Eligible Spouse” means the person to whom the Participant was married both on the date of his or her Retirement and death.

If such Participant does not have an Account balance under the Plan at the time of his or her death, payment of the annual Supplemental Retirement Benefit shall commence as of the first day of the month following the month in which the Participant’s death occurs. If the Participant has an Account balance remaining unpaid under the Plan at the time of death, payment of the annual Supplemental Retirement Benefit shall commence as of the first day of the month that is 12 months after the month in which the payment of the Account in a lump sum or the last installment payment of the Participant's Account is made, as the case may be. Subsequent payments shall be made as of the anniversary of the annuity commencement date.

This Section 8.3 shall not apply to a Participant who is an Eligible Director.

8.4 Other Conditions. Notwithstanding the foregoing provisions of this Article VIII, if the Participant's death occurs within two years of initial Plan participation, and such death occurs by reason of suicide (as reported on the Participant's death certificate or determined by the Administrator in good faith), the Participant's Beneficiary shall receive the Participant's vested Account balance as of the date of his or her death, subject to adjustment for investment return under Article VI until distributed, in full satisfaction of the Company's obligations under the Plan, and no other benefit, including a Supplemental Retirement Benefit or the amount referenced in Sections 8.1(a)(ii) and (b)(ii) above shall be payable under the Plan.

8.5 Administrator Discretion Regarding Form. Notwithstanding the foregoing provisions of this Article VIII, a Beneficiary may request that the Administrator approve an alternate form of payment of survivor benefits payable under this Article VIII from a Participant's Pre-2005 Account, which request may be granted in the sole discretion of the Administrator.

IX. ADMINISTRATION

9.1 Authority of Administrator. The Administrator shall have full power and authority to carry out the terms of the Plan, including the discretionary authority to construe and interpret the Plan, make factual findings, decide all questions of eligibility and determine the amount, manner and time of payment of any benefits hereunder. The Administrator's interpretation, construction and administration of the Plan, including any adjustment of the amount or recipient of the payments to be made, shall be binding and conclusive on all persons for all purposes. Neither the Company, including its officers, employees or directors, nor the Administrator or the Board or any member thereof, shall be liable to any person for any action taken or omitted in connection with the interpretation, construction and administration of the Plan.

9.2 Participant's Duty to Furnish Information. Each Participant shall furnish to the Administrator such information as it may from time to time request for the purpose of the proper administration of this Plan.

9.3 Claims Procedure. If a Participant or Beneficiary ("Claimant") is denied all or a portion of an expected benefit under this Plan for any reason, he or she may file a claim with the Administrator. The Administrator shall notify the Claimant within 90 days (45 days in the case of a claim for benefits payable by reason of a

Disability (a “disability claim”)) of allowance or denial of the claim, unless with respect to a claim other than a disability claim, the Claimant receives written notice from the Administrator prior to the end of the 90-day period stating that special circumstances require an extension (of up to 90 additional days) of the time for decision. In the case of a disability claim, the 45-day period provided for above may be extended by the Administrator for up to 30 days (and an additional period of up to 30 days), provided the Administrator:

(i) determines that such an extension is necessary due to matters beyond the control of the Plan,

(ii) notifies the Claimant, before the expiration of the initial 45-day period or the additional 30-day period, as the case may be, of the circumstances requiring the extension of time and the date by which the Plan expects to render a decision;

(iii) includes in the notice of the extension an explanation of (A) the standards on which entitlement to a benefit is based, (B) the unresolved issues that prevent a decision on the claim, and (C) the additional information needed to resolve those issues; and

(iv) provides the Claimant at least 45 days within which to provide the additional information described in (iii)(C) above.

In the event that a period of time is extended due to a Claimant’s failure to submit information necessary to decide a disability claim, the period for making the benefit determination shall be tolled from the date on which the notification of the extension is sent to the Claimant until the date on which the Claimant responds to the request for additional information.

The notice of the decision on a claim shall be in writing, sent by mail to Claimant’s last known address, and if a denial of the claim, shall contain the following information: (a) the specific reasons for the denial; (b) specific reference to pertinent provisions of the Plan on which the denial is based; (c) if applicable, a description of any additional information or material necessary to perfect the claim and an explanation of why such information or material is necessary; (d) an explanation of the claims review procedure and the time limits applicable, including a statement of the Claimant’s rights to bring a civil action under Section 502(a) of ERISA following an adverse determination on review; and (e) in the case of denial of a disability claim:

(i) the specific internal rule, guideline, protocol, or similar factor (if any) on which the adverse determination was based or a statement that a copy thereof is available to the Claimant free of charge upon request; and

(ii) a statement explaining the scientific or clinical judgment (if any) used in applying the terms of the Plan to the Claimant's medical circumstances or a statement that such explanation will be provided free of charge to the Claimant.

A Claimant is entitled to request a review of any denial of his or her claim by the Board. The request for review must be submitted within 60 days (180 days in the case of a disability claim) of mailing of notice of the denial. Absent a request for review within the 60-day period (180 days for a disability claim), the claim shall be deemed to be conclusively denied. The Claimant or his or her representatives shall be entitled to review all pertinent documents, and to submit issues and comments orally and in writing. The Claimant will be provided, upon request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claim. The Board shall render a review decision in writing within 60 days (45 days in the case of a disability claim) after receipt of a request for a review, provided that, in special circumstances the Board may extend the time for decision by not more than 60 days (45 days in the case of a disability claim) upon written notice to the Claimant. A claim will be reviewed by the Board taking into account all comments, documents, records, and other information submitted by the Claimant and relating to the claim, without regard to whether such information was submitted or considered in the initial benefit determination. A claim will be reviewed by the Board without any deference to the initial claim denial. In addition, in the case of denial of a disability claim, the Board will (i) if the original adverse determination was based, in whole or in part, on a medical judgment, consult a health care professional who has appropriate training and experience in the field of medicine involved in the medical judgment and who did not consult the Plan in connection with the original adverse determination; and (ii) provide the Claimant with the name of any medical or vocational experts with whom the Plan consulted in making its original determination, whether or not the determination was based on such experts' advice. The Claimant shall receive written notice of the Board's review decision, together with specific reasons for the decision and reference to the pertinent provisions of the Plan, a statement that the Claimant is entitled to receive, upon request and free of charge, reasonable access to and copies of all documents, records, and other relevant information to the claim for benefits, a statement of the Claimant's right to bring an action under ERISA Section 502(a), and in the case of denial of a disability claim:

(i) the specific internal rule, guideline, protocol, or similar factor (if any) on which the adverse determination was based or a statement that a copy thereof is available to the claimant free of charge upon request;

(ii) a statement explaining the scientific or clinical judgment (if any) used in applying the terms of the Plan to the Claimant's medical circumstances or a statement that such explanation will be provided free of charge to the Claimant; and

(iii) the following statement: "You and your Plan may have other voluntary alternative dispute resolution options, such as mediation. One way to find out what may be available is to contact your local U.S. Department of Labor Office."

The Board's decision shall be final and binding. In performing the duties under this Section 9.3, the Board shall have the same powers to interpret the Plan and make factual findings with respect thereto as are granted to the Administrator under Section 9.1.

9.4 Participant Statements. As soon as practicable after the end of each calendar quarter, a statement will be furnished or made available to each Participant showing the status of his or her Account as of the beginning and end of the calendar quarter, any changes to such Account during such calendar quarter, and such other information as the Administrator may determine. The Administrator may, in its sole discretion, change the frequency in which statements are provided to any or all Participants.

X. AMENDMENT AND TERMINATION

The Board may amend or terminate the Plan in whole or in part at any time; provided, however, the Benefits Oversight Committee of the Company shall also have the authority to amend the Plan to the extent that such amendment (i) is necessary or desirable to comply with legal requirements, (ii) is a non-substantive administrative amendment, or (iii) does not result, alone or in the aggregate with other amendments adopted by the Benefits Oversight Committee and not ratified by the Board, in an estimated annual cost to the Plan of $1 million or more. Notwithstanding the foregoing, no such amendment or termination shall have a material adverse affect on any Participant's rights under the Plan accrued as of the date of such amendment or termination except to the extent necessary to comply with Section 409A of the Code. Upon termination of the Plan, in whole or in part, the Board (i) shall cause a lump-sum payment of all benefits under the Plan, or the portion thereof being terminated, attributable to Pre-2005 Accounts to be made to all Participants or Beneficiaries or other persons entitled thereto at substantially the same time and (ii) shall cause a lump-sum payment of all benefits under the Plan, or the portion thereof being terminated, attributable to Post-2004 Accounts to be made to all Participants or Beneficiaries or other persons entitled thereto at substantially the same time to the extent such acceleration of the time and form of payment is permitted under Section 409A and the regulations and guidance issued thereunder and, if not, as provided under Articles VII and VIII.

XI. MISCELLANEOUS

11.1 No Implied Rights; Rights on Termination of Service. Neither the establishment of the Plan nor any amendment thereof shall be construed as giving any Participant, Beneficiary or any other person, individually or as a member of a group, any legal or equitable right unless such right shall be specifically provided for in the Plan or conferred by specific action of the Board or the Administrator in accordance with the terms and provisions of the Plan. Except as expressly provided in this Plan, neither the Company or other Employer nor any of their Affiliates shall be required or be liable to make any payment under the Plan.

11.2 No Employment Rights. Nothing herein shall constitute a contract of employment or of continuing service or in any manner obligate the Company or any Affiliate to continue the services of any Participant, or obligate any Participant to continue in the service of the Company or Affiliates, or as a limitation of the right of the Company or Affiliates to discharge any of their employees, with or without cause.

11.3 Unfunded Plan. The Plan is an unfunded and unsecured nonqualified deferred compensation plan. No funds shall be segregated or earmarked for any current or former Participant, Beneficiary or other person under the Plan. Payment of benefits from the Plan in respect of a Participant who is an Eligible Director that are attributable to service on the Board shall only be made by the Company and payment of benefits from the Plan in respect of a Participant who is an Eligible Director that are attributable to service on an Affiliate Board shall only be made by such Affiliate. Payment of benefits from the Plan in respect of a Participant who is an Eligible Employee shall be made only by the Employer which last employed the Participant before payments commence; provided, however, that each other Employer shall reimburse the paying Employer for the period, if any, that the Participant was employed while a Participant by such other Employer, in a manner as determined by the Company in its sole discretion. Notwithstanding the foregoing, the Company may establish one or more trusts to assist in meeting its obligations under the Plan, the assets of which shall be subject to the claims of the Company's general creditors in the event of insolvency. No current or former Participant, Beneficiary or other person, individually or as a member of a group, shall have any right, title or interest in any account, fund, grantor trust, or any asset that may be acquired by the Company in respect of its obligations under the Plan (other than as a general creditor of the Company with an unsecured claim against its general assets). The Company may also choose to use life insurance to assist in meeting obligations under the Plan. As a condition of participation in the Plan, each Participant agrees to execute any documents that may be required in connection with obtaining such insurance and to cooperate with any life insurance underwriting requirements; provided, however, that a Participant shall not be required to undergo a medical examination in connection therewith.

11.4 Nontransferability. Prior to payment thereof, no benefit under the Plan shall be assignable or subject to any manner of alienation, sale, transfer, claims of creditors, pledge, attachment or encumbrances of any kind, except pursuant to a domestic relations order (as defined in Code Section 414(p)(1)(B)) awarding benefits to an "alternate payee" (within the meaning of Code Section 414(p)(8)) that the Administrator determines satisfies the criteria set forth in paragraphs (1), (2) and (3) of Code Section 414(p) (a "DRO"). Notwithstanding any provision of the Plan to the contrary, the Plan benefits awarded to an alternate payee under a DRO may be paid pursuant to the DRO in a single lump sum to the alternate payee on the Valuation Date as soon as administratively practicable following the date the Administrator determines the order is a DRO, and such amounts, as adjusted for earnings, gains and losses, will be deducted from the Participant's Accounts as of such Valuation Date.

11.5 Successors and Assigns. The rights, privileges, benefits and obligations under the Plan are intended to be, and shall be treated as legal obligations of and binding upon the Company and each Employer, and their respective successors and assigns, including successors by merger, consolidation, reorganization or otherwise.

11.6 Applicable Law. This Plan is established under and will be construed according to the laws of the State of Oklahoma, to the extent not preempted by the laws of the United States.

11.7 Timing of Payments. Notwithstanding any provision of the Plan to the contrary, a distribution to be made as of a specified date in Article VII or Article VIII shall be made on the date specified or as soon as administratively practicable thereafter, but in no event shall any portion of the distribution attributable to a Participant's Post-2004 Accounts be made later than the last day of the same calendar year in which such date occurs or, if later and provided that Participant or Beneficiary is not permitted, directly or indirectly, to designate the year in which the distribution is made, by the 15th day of the third calendar month following the specified date. Until paid, any amount otherwise distributable from a Participant's Account shall continue to be adjusted under Article VI to reflect investment returns of the investments in which the Account is deemed invested, and the amount distributable shall be valued as of the Valuation Date coincident with or next preceding the date payment is made. In addition, if calculation of the amount of a payment is not administratively practicable due to events beyond the control of the Participant or his or her Beneficiary, a payment will be treated as made on the specified date for purposes of Code Section 409A if the payment is made during the first calendar year in which the calculation of the amount of the payment is administratively practicable.

11.8 Section 409A Compliance. To the extent applicable, it is intended that this Plan be in full compliance with the provisions of Section 409A of the Code. The Plan shall be interpreted, construed and administered in a manner consistent with this intent.

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be executed in its name by its duly authorized officer on this ____ day of ______________, 2016.

OGE Energy Corp.

By:

Exhibit 12.01

OGE Energy Corp.
Ratio of Earnings to Fixed Charges

Year ended December 31 *(In millions)*	**2016**	2015	2014	2013	2012
Earnings:					
Pre-tax income (A)	**$ 384.5**	$ 353.2	$ 396.0	$ 422.2	$ 520.1
Add: Fixed charges	**152.0**	156.3	153.9	157.2	174.4
Distributions received from equity method investment	**141.2**	139.3	143.7	51.7	—
Subtotal	**677.7**	648.8	693.6	631.1	694.5
Subtract:					
Allowance for borrowed funds used during construction	**7.5**	4.2	2.4	3.4	3.5
Other capitalized interest	**—**	—	—	2.0	4.5
Total earnings	**670.2**	644.6	691.2	625.7	686.5
Fixed Charges:					
Interest on long-term debt	**143.2**	147.8	144.6	147.6	163.4
Interest on short-term debt and other interest charges	**6.4**	5.4	6.2	5.3	8.7
Calculated interest on leased property	**2.4**	3.1	3.1	4.3	2.3
Total fixed charges	**$ 152.0**	$ 156.3	$ 153.9	$ 157.2	$ 174.4
Ratio of Earnings to Fixed Charges	**4.41**	4.12	4.49	3.98	3.94

(A) Excludes amounts attributable to income or loss from equity method investment.

Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
OGE Enogex Holdings LLC	Delaware	100.0

The above listed subsidiaries have been consolidated in the Registrant's financial statements. Certain of the Company's subsidiaries have been omitted from the list above in accordance with Rule 1-02(w) of Regulation S-X.

Exhibit 23.01

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the employees' stock ownership and retirement savings plan, Registration Statement (Form S-8 No. 333-190406) pertaining to the employees stock ownership and retirement savings plan, Registration Statement (Form S-8 No. 333-190405) pertaining to the 2013 stock incentive plan, the Registration Statement, including Post-Effective No. 1, (Form S-3ASR No. 333-200178) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-213005) pertaining to common stock and debt securities of our reports dated February 22, 2017, with respect to the consolidated financial statements and schedule of OGE Energy Corp., and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in this Annual Report (Form 10-K) for the year ended December 31, 2016.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 22, 2017

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement on Form S-8 (No. 333-92423), Registration Statement on Form S-8 (No. 333-104497), Registration Statement on Form S-8 (No. 333-190406), Registration Statement on Form S-8 (No. 333-190405), Registration Statement on Form S-3ASR (No. 333-200178) and Registration Statement on Form S-3ASR (No. 333-213005), of our report dated February 21, 2017 relating to the consolidated financial statements of Enable Midstream Partners, LP and subsidiaries, (collectively the "Partnership"), appearing in this Annual Report on Form 10-K of OGE Energy Corp. for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Houston, Texas
February 22, 2017

Exhibit 24.01

Power of Attorney

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2016; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints SEAN TRAUSCHKE, STEPHEN E. MERRILL and SCOTT FORBES and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 22nd day of February, 2017.

Sean Trauschke, Chairman, Principal Executive Officer and Director	/s/ Sean Trauschke
Frank A. Bozich, Director	/s/ Frank A. Bozich
James H. Brandi, Director	/s/ James H. Brandi
Luke R. Corbett, Director	/s/ Luke R. Corbett
John D. Groendyke, Director	/s/ John D. Groendyke
David L. Hauser, Director	/s/ David L. Hauser
Kirk Humphreys, Director	/s/ Kirk Humphreys
Robert O. Lorenz, Director	/s/ Robert O. Lorenz
Judy R. McReynolds, Director	/s/ Judy R. McReynolds
Sheila G. Talton, Director	/s/ Sheila G. Talton
Stephen E. Merrill, Principal Financial Officer	/s/ Stephen E. Merrill
Scott Forbes, Principal Accounting Officer	/s/ Scott Forbes

STATE OF OKLAHOMA)
) SS
COUNTY OF OKLAHOMA)

On the date indicated above, before me, Kelly Hamilton-Coyer, Notary Public in and for said County and State, the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, known to me to be the persons whose names are subscribed to the foregoing instrument, severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 22nd day of February, 2017.

/s/ Kelly Hamilton-Coyer
By: Kelly Hamilton-Coyer
Notary Public

My commission expires:
July 6, 2017

Exhibit 31.01

CERTIFICATIONS

I, Sean Trauschke, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2017

/s/ Sean Trauschke

Sean Trauschke

Chairman of the Board, President and Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, Stephen E. Merrill, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 22, 2017

/s/ Stephen E. Merrill

Stephen E. Merrill
Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of the Company on Form 10-K for the period ended December 31, 2016, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

February 22, 2017

/s/ Sean Trauschke

Sean Trauschke
Chairman of the Board, President and Chief Executive Officer

/s/ Stephen E. Merrill

Stephen E. Merrill
Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enable GP, LLC and
Unitholders of Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the accompanying consolidated balance sheets of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2016 and 2015, and the related consolidated statements of income, comprehensive income, cash flows, and partners’ equity for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Enable Midstream Partners, LP and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 21, 2017

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except per unit data)		
Revenues (including revenues from affiliates (Note 14)):			
Product sales	$ 1,172	$ 1,334	$ 2,300
Service revenue	1,100	1,084	1,067
Total Revenues	2,272	2,418	3,367
Cost and Expenses (including expenses from affiliates (Note 14)):			
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,017	1,097	1,914
Operation and maintenance	367	419	420
General and administrative	98	103	107
Depreciation and amortization	338	318	276
Impairments (Note 8, Note 11)	9	1,134	8
Taxes other than income taxes	58	59	56
Total Cost and Expenses	1,887	3,130	2,781
Operating (Loss) Income	385	(712)	586
Other Income (Expense):			
Interest expense (including expenses from affiliates (Note 14))	(99)	(90)	(70)
Equity in earnings of equity method affiliate	28	29	20
Other, net	—	2	(1)
Total Other Income (Expense)	(71)	(59)	(51)
Income (Loss) Before Income Taxes	314	(771)	535
Income tax expense	1	—	2
Net Income (Loss)	$ 313	$ (771)	$ 533
Less: Net income (loss) attributable to noncontrolling interest	1	(19)	3
Net Income (Loss) Attributable to Limited Partners	$ 312	$ (752)	$ 530
Less: Series A Preferred Unit distributions (Note 5)	22	—	—
Net Income (Loss) Attributable to Common and Subordinated Units (Note 4)	$ 290	(752)	$ 530
Basic earnings (loss) per unit (Note 4)			
Common units	$ 0.69	$ (1.78)	$ 1.29
Subordinated units	$ 0.68	$ (1.78)	$ 1.28
Diluted earnings (loss) per unit (Note 4)			
Common units	$ 0.69	$ (1.78)	$ 1.29
Subordinated units	$ 0.68	$ (1.78)	$ 1.28

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2016	2015	2014
		(In millions)	
Net Income (Loss)	$ 313	$ (771)	$ 533
Comprehensive Income (Loss)	313	(771)	533
Less: Comprehensive income (loss) attributable to noncontrolling interest	1	(19)	3
Comprehensive Income (Loss) Attributable to Enable Midstream Partners, LP	$ 312	$ (752)	$ 530

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2016	December 31, 2015
	(In millions, except units)	
Current Assets:		
Cash and cash equivalents	$ 6	$ 4
Restricted cash	17	—
Accounts receivable, net	249	245
Accounts receivable—affiliated companies	13	21
Inventory	41	53
Gas imbalances	41	23
Other current assets	29	35
Total current assets	396	381
Property, Plant and Equipment:		
Property, plant and equipment	11,567	11,293
Less accumulated depreciation and amortization	1,424	1,162
Property, plant and equipment, net	10,143	10,131
Other Assets:		
Intangible assets, net	306	333
Investment in equity method affiliate	329	344
Other	38	37
Total other assets	673	714
Total Assets	$ 11,212	$ 11,226
Current Liabilities:		
Accounts payable	$ 181	$ 248
Accounts payable—affiliated companies	3	9
Short-term debt	—	236
Taxes accrued	30	30
Gas imbalances	35	25
Accrued compensation	37	23
Customer deposits	31	18
Other	45	26
Total current liabilities	362	615
Other Liabilities:		
Accumulated deferred income taxes, net	10	8
Notes payable—affiliated companies	—	363
Regulatory liabilities	19	18
Other	34	20
Total other liabilities	63	409
Long-Term Debt	2,993	2,671
Commitments and Contingencies (Note 15)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at December 31, 2016 and 0 issued and outstanding at December 31, 2015)	362	—
Common units (224,535,454 issued and outstanding at December 31, 2016 and 214,541,422 issued and outstanding at December 31, 2015, respectively)	3,737	3,714
Subordinated units (207,855,430 issued and outstanding at December 31, 2016 and December 31, 2015, respectively)	3,683	3,805
Noncontrolling interest	12	12
Total Partners' Equity	7,794	7,531
Total Liabilities and Partners' Equity	$ 11,212	$ 11,226

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Cash Flows from Operating Activities:			
Net income (loss)	$ 313	$ (771)	$ 533
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	338	318	276
Deferred income taxes	2	(1)	1
Impairments	9	1,134	8
Loss on sale/retirement of assets	17	5	—
Equity in earnings of equity method affiliate, net of distributions	—	5	3
Equity based compensation	13	9	13
Amortization of debt expense and discount (premium)	(3)	(2)	(1)
Changes in other assets and liabilities:			
Accounts receivable, net	(4)	9	52
Accounts receivable—affiliated companies	8	6	1
Inventory	12	10	7
Gas imbalance assets	(18)	22	(35)
Other current assets	6	2	17
Other assets	(1)	(4)	5
Accounts payable	(34)	—	(138)
Accounts payable—affiliated companies	(6)	(29)	(2)
Gas imbalance liabilities	10	12	—
Other current liabilities	45	6	29
Other liabilities	14	(5)	—
Net cash provided by operating activities	721	726	769
Cash Flows from Investing Activities:			
Capital expenditures	(383)	(869)	(837)
Acquisitions, net of cash acquired	—	(80)	—
Proceeds from sale of assets	1	3	13
Return of investment in equity method affiliate	15	8	198
Investment in equity method affiliate	—	(8)	(189)
Net cash used in investing activities	(367)	(946)	(815)
Cash Flows from Financing Activities:			
Repayment of long term debt	—	—	(1,500)
Proceeds from long term debt, net of issuance costs	—	450	1,635
Proceeds from revolving credit facility	1,734	585	122
Repayment of revolving credit facility	(1,408)	(275)	(495)
Increase (decrease) in short-term debt	(236)	(17)	253
Repayment of notes payable—affiliated companies	(363)	—	—
Proceeds from issuance of common units	137	—	464
Proceeds from issuance of Series A Preferred Units, net of issuance costs	362	—	—
Distributions	(561)	(531)	(529)
Net cash provided by (used in) financing activities	(335)	212	(50)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	19	(8)	(96)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	4	12	108
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 23	$ 4	$ 12

See Notes to the Consolidated Financial Statements

Exhibit 99.05

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
				(In millions)				
Balance as of December 31, 2013	—	$ —	390	$ 8,148	—	$ —	$ 33	$ 8,181
Conversion to subordinated units	—	—	(208)	(4,372)	208	4,372	—	—
Net income	—	—	—	349	—	181	3	533
Issuance of IPO common units	—	—	25	464	—	—	—	464
Issuance of common units upon interest acquisition of SESH	—	—	6	161	—	—	—	161
Distributions	—	—	—	(410)	—	(114)	(5)	(529)
Equity based compensation, net of units for employee taxes	—	—	1	13	—	—	—	13
Balance as of December 31, 2014	—	$ —	214	$ 4,353	208	$ 4,439	$ 31	$ 8,823
Net loss	—	—	—	(379)	—	(373)	(19)	(771)
Issuance of common units upon interest acquisition of SESH	—	—	—	1	—	—	—	1
Distributions	—	—	—	(270)	—	(261)	—	(531)
Equity based compensation, net of units for employee taxes	—	—	—	9	—	—	—	9
Balance as of December 31, 2015	—	$ —	214	$ 3,714	208	$ 3,805	$ 12	$ 7,531
Net income	—	22	—	147	—	143	1	313
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Issuance of common units	—	—	10	137	—	—	—	137
Distributions	—	(22)	—	(274)	—	(265)	(1)	(562)
Equity based compensation, net of units for employee taxes	—	—	—	13	—	—	—	13
Balance as of December 31, 2016	15	$ 362	224	$ 3,737	208	$ 3,683	$ 12	$ 7,794

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a Delaware limited partnership formed on May 1, 2013 by CenterPoint Energy, OGE Energy and ArcLight, pursuant to the terms of the MFA. The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers. The Partnership's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Crude oil gathering assets are located in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. The Partnership's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma, and our investment in SESH, a pipeline extending from Louisiana to Alabama.

CenterPoint Energy and OGE Energy each have 50% of the management interests in Enable GP. Enable GP is the general partner of the Partnership and has no other operating activities. Enable GP is governed by a board made up of two representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and three independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

At December 31, 2016, CenterPoint Energy held approximately 54.1% of the Partnership's common and subordinated units, or 94,151,707 common units and 139,704,916 subordinated units, and OGE Energy held approximately 25.7% of the Partnership's common and subordinated units, or 42,832,291 common units and 68,150,514 subordinated units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's General Partner (Enable GP) on an annual or continuing basis and may not remove Enable GP without at least a 75% vote by all unitholders, including all units held by the Partnership's limited partners, and Enable GP and its affiliates, voting together as a single class.

For the period from December 31, 2013 through May 29, 2014, the financial statements reflect a 24.95% interest in SESH. For the period of May 30, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units. As of December 31, 2016, the Partnership owned a 50% interest in SESH. See Note 9 for further discussion of SESH.

In addition, for the years ended December 31, 2016, 2015 and 2014, the Partnership held a 50% ownership interest in Atoka and consolidated Atoka in its Consolidated Financial Statements as EOIT acted as the managing member of Atoka and had control over the operations of Atoka.

On April 16, 2014, the Partnership completed the IPO of 25,000,000 common units at a price to the public of $20.00 per common unit. The Partnership received net proceeds of $464 million from the sale of the common units, after deducting underwriting discounts and commissions, the structuring fee and offering expenses. In connection with the IPO, underwriters exercised their option to purchase 3,750,000 additional common units, which were fulfilled with units held by ArcLight. As a result, the Partnership did not receive any proceeds from the sale of common units pursuant to the exercise of the underwriters' option to purchase additional common units. The exercise of the underwriters' option to purchase additional common units did not affect the total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all outstanding units. The Partnership retained the net proceeds of the IPO for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts. In connection with the IPO, 139,704,916 of CenterPoint Energy's common units and 68,150,514 of OGE Energy's common units were converted into subordinated units.

Basis of Presentation

The accompanying consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP.

For a description of the Partnership's reportable segments, see Note 18.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition

The Partnership generates the majority of its revenues from midstream energy services, including natural gas gathering, processing, transportation and storage and crude oil gathering. The Partnership performs these services under various contractual arrangements, which include fee-based contract arrangements and arrangements pursuant to which it purchases and resells commodities in connection with providing the related service and earns a net margin for its fee. While the Partnership's transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to a customer. The Partnership reflects revenue as Product sales and Service revenue on the Consolidated Statements of Income as follows:

Product sales: Product sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and used in connection with providing the Partnership's midstream services.

Service revenue: Service revenue represents all other revenue generated as a result of performing the Partnership's midstream services.

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts receivable, net or Accounts receivable—affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Revenues on the Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil gathering services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The Partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership had $34 million and $30 million of deferred revenues, including deferred revenue—affiliated companies, on the Consolidated Balance Sheets at December 31, 2016 and 2015, respectively.

The Partnership relies on certain key natural gas producer customers for a significant portion of natural gas and NGLs supply. The Partnership relies on certain key utilities for a significant portion of transportation and storage demand. The Partnership depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally, for the years ended December 31, 2016, 2015 and 2014, one third party purchased approximately 22%, 18% and 21%, respectively, of the NGLs delivered off our system, which accounted for approximately $129 million, $108 million and $235 million, or 6%, 4% and 7%, respectively, of total revenues. Other than revenues from affiliates discussed in Note 14, there are no other revenue concentrations with individual customers in the years ended December 31, 2016, 2015 and 2014.

Natural Gas and Natural Gas Liquids Purchases

Cost of natural gas and natural gas liquids represents cost of our natural gas and natural gas liquids purchased exclusive of depreciation, Operation and maintenance and General and administrative expenses and consists primarily of product and fuel costs. Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable or Accounts Payable-affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Cost of natural gas and natural gas liquids, excluding Depreciation and amortization on the Consolidated Statements of Income.

Operation and Maintenance and General and Administrative Expense

Operation and maintenance expense represents the cost of our service related revenues and consists primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses directly related with the operations of assets. General and administrative expense represents cost incurred to manage the business. This expense includes cost of general corporate services, such as treasury, accounting, legal, information technology and human resources and all other expenses necessary or appropriate to the conduct of business. Any Operation and maintenance expense and General and administrative expense associated with product sales is immaterial.

Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2016 or 2015.

Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets.

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. Intangible assets are amortized on a straight-line basis over their useful lives using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Income Taxes

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries, Enable Midstream Services and Enable Muskogee Intrastate Transmission) and are taxable at the individual partner level. For more information, see Note 16.

We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future taxes attributable to the difference between financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of tax net operating loss carryforwards. In the event future utilization is determined to be unlikely, a valuation allowance is provided to reduce the tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the period in which the temporary differences and carryforwards are expected to be recovered or settled. The effect of a change in tax rates is recognized in the period which includes the enactment date. The Partnership recognizes interest and penalties as a component of income tax expense.

Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. The Consolidated Balance Sheets have $6 million and $4 million of cash and cash equivalents as of December 31, 2016 and 2015, respectively.

Restricted Cash

Restricted cash consists of cash which is restricted by agreements with third parties. The Consolidated Balance Sheets have $17 million of restricted cash as of December 31, 2016. The Partnership had no restricted cash as of December 31, 2015.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, we evaluate our customers' financial strength based on aging of accounts receivable, payment history and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $3 million allowance for doubtful accounts was required as of December 31, 2016, and no allowance for doubtful accounts was required as of December 31, 2015.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or net realizable value. During the years ended December 31, 2016 and 2014, the Partnership recorded write-downs to net realizable value related to materials and supplies inventory disposed or identified as excess or obsolete of $1 million and $9 million, respectively. There were no material write-downs related to materials and supplies inventory for the year ended December 31, 2015. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to operation and maintenance expense on the Consolidated Statements of Income or capitalized to property, plant and equipment on the Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the transportation and storage segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the gathering and processing segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or net realizable value. During the years ended December 31, 2016, 2015 and 2014, the Partnership recorded write-downs to net realizable value related to natural gas and natural gas liquids inventory of $3 million, $13 million and $4 million, respectively. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of natural gas and natural gas liquids, excluding depreciation and amortization on the Consolidated Statements of Income.

	December 31,	
	2016	2015
	(In millions)	
Materials and supplies	$ 30	$ 34
Natural gas and natural gas liquids inventories	11	19
Total	$ 41	$ 53

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or natural gas depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Long-Lived Assets (including Intangible Assets)

The Partnership records property, plant and equipment and intangible assets at historical cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Operation and maintenance expense. The Partnership expenses repair and maintenance costs as incurred. Repair, removal and maintenance costs are included in the Consolidated Statements of Income as Operation and maintenance expense.

Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. For more information, see Note 11.

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the transportation and storage and gathering and processing segment level at the operating segment level. For more information, see Note 8.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the transportation and storage segment. The Partnership's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of each of December 31, 2016 and 2015, these removal costs of $19 million and $18 million, respectively, are classified as Regulatory liabilities in the Consolidated Balance Sheets.

Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for combined entities that apply guidance for accounting for regulated operations. Capitalized interest represents the approximate net composite interest cost of borrowed funds used for construction. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the years ended December 31, 2016, 2015 and 2014, the Partnership capitalized interest and AFUDC of $4 million, $10 million and $8 million, respectively.

Derivative Instruments

The Partnership is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. At times, the Partnership utilizes derivative instruments such as physical forward contracts, financial futures and swaps to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership's Consolidated Balance Sheets at their fair value unless the Partnership elects hedge accounting or the normal purchase and sales exemption for qualified physical transactions. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized in Product sales in the Consolidated Statements of Income. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

The Partnership's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

Fair Value Measurements

The Partnership determines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

Equity Based Compensation

The Partnership awards equity based compensation to officers, directors and employees under the Long Term Incentive Plan. All equity based awards to officers, directors and employees under the Long Term Incentive Plan, including grants of performance units, time-based phantom units (phantom units) and time-based restricted units (restricted units) are recognized in the Consolidated Statements of Income based on their fair values. The fair value of the phantom units and restricted units are based on the closing market price of the Partnership's common unit on the grant date. The fair value of the performance units is estimated on the grant date using a lattice-based valuation model that factors in information, including the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the phantom unit and restricted unit awards is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period. The vesting of the performance unit awards is also contingent upon the probable outcome of the market condition. Depending on forfeitures and actual vesting, the compensation expense recognized related to the awards could increase or decrease.

Reverse Unit Split

On March 25, 2014, the Partnership effected a 1 for 1.279082616 reverse unit split. All unit and per unit amounts presented within the consolidated financial statements reflect the effects of the reverse unit split.

Third Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On February 18, 2016, in connection with the closing of the private placement of 14,520,000 Series A Preferred Units and pursuant to the Purchase Agreement, the General Partner adopted the Third Amended and Restated Agreement of Limited Partnership which, among other things, authorized and established the terms of the Series A Preferred Units and the other series of preferred units that are issuable upon conversion of the Series A Preferred Units. For further information related to the issuance of the Series A Preferred Units, see Note 5.

Fourth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On June 22, 2016, the General Partner adopted the Fourth Amended and Restated Agreement of Limited Partnership (the Partnership Agreement), which changed the last permitted distribution date with respect to each fiscal quarter from 45 days following the close of such quarter to 60 days following the close of such quarter.

(2) New Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606),” which supersedes the revenue recognition requirements in “Revenue Recognition (Topic 605).” Topic 606 is based on the core principle that revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. Topic 606 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, including significant judgments and changes in judgments and assets recognized from costs incurred to obtain or fulfill a contract.

Topic 606 is effective for fiscal years beginning after December 15, 2017, and interim periods within those years, with early adoption permitted in 2017, however we do not plan to adopt the standard early. Entities will have the option to apply the standard using a full retrospective or modified retrospective adoption method. The Partnership expects to adopt this ASU using the modified retrospective method. Our evaluation of the impact on our Consolidated Financial Statements and related disclosures is ongoing and not complete. In connection with our assessment work, we formed an implementation work team, completed training on the Topic 606 revenue recognition model and are continuing our review of contracts relative to the provisions of Topic 606.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The Partnership expects to adopt this standard in the first quarter of 2019 and is currently evaluating the impact of this standard on our Consolidated Financial Statements and related disclosures. In connection with our assessment work, we formed an implementation work team and are continuing a review of our contracts relative to the provisions of the lease standard.

Share-Based Compensation

In March 2016, the FASB issued ASU No. 2016-09, "Compensation—Stock Compensation (Topic 718)." This standard makes several modifications to Topic 718 related to the accounting for forfeitures, employer tax withholding on share-based compensation and the financial statement presentation of excess tax benefits or deficiencies. ASU 2016-09 also clarifies the statement of cash flows presentation for certain components of share-based awards. The standard is effective for interim and annual reporting periods beginning in 2017, although early adoption is permitted. The Partnership will adopt the amendment in the fourth quarter of 2017, and does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The guidance requires application using a modified retrospective method. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Statement of Cash Flows

In August 2016, the FASB issued ASU No. 2016-15, "Statement of Cash Flows (Topic 230): Classification of Certain Cash Receipts and Cash Payments." This standard is intended to reduce existing diversity in practice in how certain transactions are presented on the statement of cash flows. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted. The guidance requires application using a retrospective transition method. The Partnership will adopt ASU No. 2016-15 in the first quarter of 2017 and has determined the amendment will not have a material impact on our Consolidated Financial Statements and related disclosures.

Income Taxes

In October 2016, the FASB issued ASU No. 2016-16, "Income Taxes (Topic 740): Intra-Entity Transfers of Assets Other Than Inventory." This standard requires entities to recognize the tax consequences of an intra-entity transfer of an asset other than inventory when the transfer occurs. The standard is effective for interim and annual reporting periods beginning after December 15, 2017, although early adoption is permitted as of the beginning of an annual period (i.e., only in the first interim period). The guidance requires application using a modified retrospective approach. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Consolidated Financial Statements and related disclosures.

Restricted Cash

In November 2016, the FASB issued ASU No. 2016-18, “Statement of Cash Flows (Topic 230): Restricted Cash.” The standard is intended to provide specific guidance on the cash flow classification and presentation of changes in restricted cash. The Partnership early adopted the amendment in the fourth quarter of 2016, using a retrospective basis. As of December 31, 2016, the Partnership had restricted cash of $17 million. The Partnership had no restricted cash as of December 31, 2015.

(3) Acquisition

On April 22, 2015, Enable entered into an agreement with Monarch Natural Gas, LLC, pursuant to which the Partnership agreed to acquire approximately 106 miles of gathering pipeline, approximately 5,000 horsepower of associated compression, right-of-ways and certain other midstream assets that provide natural gas gathering services in the Greater Granite Wash area of Texas. The transaction closed on May 1, 2015. The aggregate purchase price for this transaction was approximately $80 million, which was funded from cash generated from operations and borrowings under our Revolving Credit Facility.

The acquisition was accounted for as a business combination. During the third quarter of 2015, the Partnership, with the assistance of a third-party valuation expert, finalized the purchase price allocation as of May 1, 2015.

Purchase price allocation (in millions):		
Property, plant and equipment	$	51
Intangibles		10
Goodwill		19
Total	$	80

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 15 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Anadarko Basin. See Note 8 for further information related to the Partnership’s goodwill impairment. The Partnership incurred less than $1 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Consolidated Statements of Income.

(4) Earnings Per Limited Partner Unit

Basic and diluted earnings per limited partner unit is calculated by dividing net income (loss) allocable to common and subordinated unitholders by the weighted average number of common and subordinated units outstanding during the period. Any common units issued during the period are included on a weighted average basis for the days in which they were outstanding. The dilutive effect of the unit-based awards discussed in Note 17 was less than $0.01 per unit during the years ended December 31, 2016, 2015 and 2014.

The following table illustrates the Partnership's calculation of earnings (loss) per unit for common and subordinated units:

	Year Ended December 31,		
	2016	2015	2014
	(In millions, except per unit data)		
Net income (loss)	$ 313	$ (771)	$ 533
Net income (loss) attributable to noncontrolling interest	1	(19)	3
Series A Preferred Unit distribution	22	—	—
General partner interest in net income	—	—	—
Net income (loss) available to common and subordinated unitholders	$ 290	$ (752)	$ 530
Net income (loss) allocable to common units	$ 148	$ (381)	$ 339
Net income (loss) allocable to subordinated units	142	(371)	191
Net income (loss) available to common and subordinated unitholders	$ 290	$ (752)	$ 530
Net income (loss) allocable to common units	$ 148	$ (381)	$ 339
Dilutive effect of Series A Preferred Unit distribution	—	—	—
Dilutive effect of performance units	—	—	—
Diluted net income (loss) allocable to common units	148	(381)	339
Diluted net income (loss) allocable to subordinated units	142	(371)	191
Total	$ 290	$ (752)	$ 530
Basic weighted average number of outstanding			
Common units	216	214	264
Subordinated units	208	208	148
Total	424	422	412
Basic earnings (loss) per unit			
Common units	$ 0.69	$ (1.78)	$ 1.29
Subordinated units	$ 0.68	$ (1.78)	$ 1.28
Basic weighted average number of outstanding common units	216	214	264
Dilutive effect of Series A Preferred Units	—	—	—
Dilutive effect of performance units	—	—	—
Diluted weighted average number of outstanding common units	216	214	264
Diluted weighted average number of outstanding subordinated units	208	208	148
Total	424	422	412
Diluted earnings (loss) per unit			
Common units	$ 0.69	$ (1.78)	$ 1.29
Subordinated units	$ 0.68	$ (1.78)	$ 1.28

(5) Enable Midstream Partners, LP Partners' Equity

The Partnership Agreement requires that, within 60 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date. The Partnership did not make distributions for the period that began on April 1, 2014 and ended on April 15, 2014, the day prior to the closing of the IPO, other than the required distributions to CenterPoint Energy, OGE Energy and ArcLight under the Partnership Agreement.

On February 14, 2014, May 14, 2014 and August 14, 2014, the Partnership distributed $114 million, $155 million and $22 million to the unitholders of record as of January 1, 2014, April 1, 2014 and April 1, 2014, respectively in accordance with the Partnership's First Amended and Restated Agreement of Limited Partnership.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders during 2016, 2015 and 2014 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution		Total Cash Distribution	
December 31, 2016[(1)]	February 21, 2017	February 28, 2017	$	0.318	$	137
September 30, 2016	November 14, 2016	November 22, 2016	$	0.318	$	134
June 30, 2016	August 16, 2016	August 23, 2016	$	0.318	$	134
March 31, 2016	May 6, 2016	May 13, 2016	$	0.318	$	134
December 31, 2015	February 2, 2016	February 12, 2016	$	0.318	$	134
September 30, 2015	November 3, 2015	November 13, 2015	$	0.318	$	134
June 30, 2015	August 3, 2015	August 13, 2015	$	0.316	$	134
March 31, 2015	May 5, 2015	May 15, 2015	$	0.3125	$	132
December 31, 2014	February 4, 2015	February 13, 2015	$	0.30875	$	130
September 30, 2014	November 4, 2014	November 14, 2014	$	0.3025	$	128
June 30, 2014 [(2)]	August 4, 2014	August 14, 2014	$	0.2464	$	104

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on February 10, 2017, to be paid on February 28, 2017, to common and subordinated unitholders of record at the close of business on February 21, 2017.

(2) The quarterly distribution for three months ended June 30, 2014 was prorated for the period beginning immediately after the closing of the Partnership's IPO, April 16, 2014 through June 30, 2014.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution		Total Cash Distribution	
December 31, 2016[(1)]	February 10, 2017	February 15, 2017	$	0.625	$	9
September 30, 2016	November 1, 2016	November 14, 2016	$	0.625	$	9
June 30, 2016	August 2, 2016	August 12, 2016	$	0.625	$	9
March 31, 2016[(2)]	May 6, 2016	May 13, 2016	$	0.2917	$	4

(1) The board of directors of Enable GP declared this $0.625 per Series A Preferred Unit cash distribution on February 10, 2017, which was paid on February 15, 2017 to Series A Preferred unitholders of record at the close of business on February 10, 2017.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus (as defined in the Partnership Agreement) in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units or subordinated units that they own.

Subordinated Units

General

As of December 31, 2016, all subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because for a period of time, defined by the Partnership Agreement as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received distributions of available cash each quarter from operating surplus in an amount equal to the minimum quarterly distribution plus any arrearages on minimum quarterly distributions on the common units from prior quarters. In addition, the subordinated units are not entitled to arrearages on minimum quarterly distributions. On the expiration of the subordination period, the subordinated units will convert to common units on a one-for-one basis.

Subordination Period

The subordination period began on the closing date of the IPO and expires on the first to occur of the following dates: (1) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2017 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal or exceed $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date; (b) the adjusted operating surplus generated during each of the three consecutive, non-overlapping four-quarter periods immediately preceding that date equaled or exceeded the sum $1.15 (the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during those periods on a fully diluted weighted average basis; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units or (2) the first business day following the distribution of available cash in respect of any quarter beginning with the quarter ending June 30, 2015 that the following tests are met: (a) distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150% of the annualized minimum quarterly distribution) for the four consecutive quarter period immediately preceding that date; (b) the adjusted operating surplus generated during the four consecutive quarter period immediately preceding that date equaled or exceed $1.725 per unit (150% of the annualized minimum quarterly distribution) on all of the common units and subordinated units outstanding during that period on a fully diluted weighted average basis plus the corresponding incentive distribution rights; and (c) there are no arrearages in the payment of the minimum quarterly distributions on the common units.

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership’s common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;
- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership

Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

2016 Equity Issuance

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting discounts, structuring fees and offering expenses) of $137 million from the offering.

(6) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2016	December 31, 2015
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	37	$ 6,987	$ 6,478
Transportation and Storage	36	4,498	4,444
Construction work-in-progress		82	371
Total		$ 11,567	$ 11,293
Accumulated depreciation:			
Gathering and Processing		681	510
Transportation and Storage		743	652
Total accumulated depreciation		1,424	1,162
Property, plant and equipment, net		$ 10,143	$ 10,131

The Partnership recorded depreciation expense of $311 million, $291 million and $249 million during the years ended December 31, 2016, 2015 and 2014, respectively.

(7) Intangible Assets, Net

As of December 31, 2016, the Partnership has $405 million in intangible assets associated with customer relationships due to the acquisition of Enogex and Monarch Natural Gas, LLC.

Intangible assets consist of the following:

	December 31,	
	2016	2015
	(In millions)	
Customer relationships:		
Total intangible assets	$ 405	$ 405
Accumulated amortization	99	72
Net intangible assets	$ 306	$ 333

The Partnership determined that intangible assets related to customer relationships have a weighted average useful life of 15 years. Intangible assets do not have any significant residual value or renewal options of existing terms. There are no intangible assets with indefinite useful lives.

The Partnership recorded amortization expense of $27 million, $27 million and $27 million during the years ended December 31, 2016, 2015 and 2014, respectively. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years:

	2017	2018	2019	2020	2021
	(In millions)				
Expected amortization of intangible assets	$ 27	$ 27	$ 27	$ 27	$ 27

(8) Goodwill

For the periods ended prior to September 30, 2015, the goodwill associated with the gathering and processing reportable segment is primarily related to the acquisitions of Enogex, Waskom and Monarch. The Partnership recognized $438 million of goodwill as a result of the acquisition of Enogex, which occurred at the time of the formation of the Partnership in 2013. The $579 million of goodwill associated with the transportation and storage reportable segment was related to the original acquisitions of EGT and MRT in 1997 by predecessors of the Partnership. Subsequent to the completion of the October 1, 2014 annual test and previous interim assessment as of December 31, 2014, the crude oil and natural gas industry was impacted by further commodity price declines, which consequently resulted in decreased producer activity in certain regions in which the Partnership operates. Due to the continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, the Partnership determined that the impact on our forecasted discounted cash flows for our gathering and processing and transportation and storage reportable segments would be significantly reduced. As a result, when the Partnership performed our annual goodwill impairment analysis as of October 1, 2015, we determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Consolidated Statements of Income for the year ended December 31, 2015. As a result, the Partnership did not have any goodwill recorded as of December 31, 2016 and 2015.

Exhibit 99.05

The change in carrying amount of goodwill in each of our reportable segments is as follows:

	Gathering and Processing	Transportation and Storage	Total
	(in millions)		
Balance as of December 31, 2014	$ 489	$ 579	$ 1,068
Acquisition of Monarch	19	—	19
Goodwill impairment	(508)	(579)	(1,087)
Balance as of December 31, 2015	$ —	$ —	$ —
Balance as of December 31, 2016	$ —	$ —	$ —

(9) Investment in Equity Method Affiliate

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence.

For the period December 31, 2013 through May 29, 2014, the Partnership held a 24.95% interest in SESH, which is accounted for as an investment in equity method affiliate, and CenterPoint Energy indirectly owned a 25.05% interest in SESH. Pursuant to the MFA, that interest could be contributed to the Partnership upon exercise of certain put or call rights, under which CenterPoint Energy would contribute to the Partnership CenterPoint Energy's retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised. On May 13, 2014, CenterPoint Energy exercised its put right with respect to a 24.95% interest in SESH. Pursuant to the put right, on May 30, 2014, CenterPoint Energy contributed a 24.95% interest in SESH to the Partnership in exchange for 6,322,457 common units, which had a fair value of $161 million based upon the closing market price of the Partnership's common units. For the period from May 30, 2014 through June 29, 2015, the Partnership held a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to its remaining 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed a 0.1% interest in SESH to the Partnership in exchange for 25,341 common units, which had a fair value of $1 million based upon the closing market price of the Partnership's common units. Spectra Energy Partners, LP owns the remaining 50% interest in SESH. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its limited partner interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP could have the right to purchase our interest in SESH at fair market value, subject to certain exceptions. As of December 31, 2016, the Partnership owned a 50% interest in SESH.

In connection with CenterPoint Energy's exercise of its put right with respect to its 24.95% interest in SESH, the parties agreed to allocate the distributions for the quarter ended June 30, 2014 on (i) the SESH interest acquired by Enable and (ii) the Enable units issued to CenterPoint Energy for the SESH interest pro rata based on the time each party held the relevant interest. On July 25, 2014, the Partnership received a $7 million distribution from SESH for the three month period ended June 30, 2014, representing the Partnership's 49.90% interest in SESH. Under the terms of the agreement, the Partnership made a payment of approximately $1 million to CenterPoint Energy related to the additional 24.95% interest during the quarter ending September 30, 2014.

On June 13, 2014, SESH made a special distribution of the proceeds of its $400 million senior note issuance, less debt issuance costs, which resulted in a $198 million return of investment to the Partnership. In August 2014, the Partnership contributed $187 million to SESH which was utilized to repay SESH's $375 million senior notes due August 2014, increasing the book value of Enable's 50% investment in SESH. The Partnership and other members of SESH intend to contribute or otherwise return the remaining special distribution to SESH as necessary for general SESH purposes, including capital expenditures associated with SESH's expansion plans.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. During the years ended December 31, 2016, 2015 and 2014, the Partnership billed SESH $13 million, $12 million and $13 million, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliate under the Other Income (Expense) caption in the Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014.

Investment in Equity Method Affiliate:

		(In millions)
Balance as of December 31, 2013	**$**	**198**
Interest acquisition of SESH		161
Return of investment from SESH refinancing		(198)
Additional investment in SESH		187
Equity in earnings of equity method affiliate		20
Contributions to equity method affiliate		3
Distributions from equity method affiliate[(1)]		(23)
Balance as of December 31, 2014		**348**
Interest acquisition of SESH		1
Equity in earnings of equity method affiliate		29
Contributions to equity method affiliate		8
Distributions from equity method affiliate[(1)]		(42)
Balance as of December 31, 2015		**344**
Equity in earnings of equity method affiliate		28
Distributions from equity method affiliate[(1)]		(43)
Balance as of December 31, 2016	**$**	**329**

(1) Distributions from equity method affiliate includes a $28 million, $34 million and $23 million return on investment and a $15 million, $8 million and zero return of investment for the years ended December 31, 2016, 2015 and 2014, respectively.

Equity in Earnings of Equity Method Affiliate:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
SESH	$ 28	$ 29	$ 20

Distributions from Equity Method Affiliate:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
SESH [(1)]	$ 43	$ 42	$ 23

(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.

Summarized financial information of SESH:

	December 31,	
	2016	2015
	(In millions)	
Balance Sheet Data:		
Current assets	$ 31	$ 45
Property, plant and equipment, net	1,110	1,127
Total assets	$ 1,141	$ 1,172
Current liabilities	$ 18	$ 18
Long-term debt	397	397
Members' equity	726	757
Total liabilities and members' equity	$ 1,141	$ 1,172
Reconciliation:		
Investment in SESH	$ 329	$ 344
Less: Capitalized interest on investment in SESH	(1)	(1)
Add: Basis differential, net of amortization	35	36
The Partnership's share of members' equity	$ 363	$ 379

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Income Statement Data:			
Revenues	$ 115	$ 115	$ 108
Operating income	$ 73	$ 71	$ 69
Net income	$ 55	$ 57	$ 48

(10) Debt

The following table presents the Partnership's outstanding debt as of December 31, 2016 and 2015.

	December 31,	
	2016	2015
	(In millions)	
Commercial Paper	$ —	$ 236
Revolving Credit Facility	636	310
2015 Term Loan Agreement	450	450
Notes payable—affiliated companies (Note 14)	—	363
2019 Notes	500	500
2024 Notes	600	600
2044 Notes	550	550
EOIT Senior Notes	250	250
Premium (Discount) on long-term debt	17	23
Total debt	3,003	3,282
Less: Short-term debt[1]	—	236
Less: Unamortized debt expense	10	12
Less: Notes payable—affiliated companies	—	363
Total long-term debt	$ 2,993	$ 2,671

(1) There were no commercial paper borrowings outstanding as of December 31, 2016. Short-term debt includes $236 million of commercial paper as of December 31, 2015.

Maturities of outstanding debt, excluding unamortized premiums, are as follows (in millions):

2017	$ —
2018	450
2019	500
2020	886
2021	—
Thereafter	1,150

Revolving Credit Facility

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. As of December 31, 2016, there were $636 million of principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 2.21% as of December 31, 2016.

The Revolving Credit Facility provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2016, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2016, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership's credit ratings. The commitment fee is recorded as interest expense in the Partnership's Consolidated Statements of Income.

The Revolving Credit Facility contains a financial covenant requiring us to maintain a ratio of consolidated funded debt to consolidated EBITDA as defined under the Revolving Credit Facility as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for any three fiscal quarters including and following any fiscal quarter in which the aggregate value of one or more acquisitions by us or certain of our subsidiaries with a purchase price of at least $25 million in the aggregate, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The Revolving Credit Facility also contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the Revolving Credit Facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the Revolving Credit Facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Commercial Paper

The Partnership has a commercial paper program pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was zero and $236 million outstanding under our commercial paper program as of December 31, 2016 and 2015, respectively. On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a non-investment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a non-investment grade rating. As a result of the downgrade, the Partnership repaid its outstanding borrowings under the commercial paper program upon maturity and did not issue any additional commercial paper.

Term Loan Agreement

On July 31, 2015, the Partnership entered into a Term Loan Agreement dated as of July 31, 2015, providing for an unsecured three-year $450 million term loan agreement (2015 Term Loan Agreement). The entire $450 million principal amount of the 2015 Term Loan Agreement was borrowed by the Partnership on July 31, 2015. The 2015 Term Loan Agreement contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Agreement, in each case, for an additional one-year term. The 2015 Term Loan Agreement provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of December 31, 2016, there was $450 million outstanding under the 2015 Term Loan Agreement.

The 2015 Term Loan Agreement provides that outstanding borrowings bear interest at LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of December 31, 2016, the applicable margin for LIBOR-based borrowings under the 2015 Term Loan Agreement was 1.375% based on our credit ratings. As of December 31, 2016, the weighted average interest rate of the 2015 Term Loan Agreement was 1.86%.

The 2015 Term Loan Agreement contains substantially the same covenants as the Revolving Credit Facility.

Senior Notes

On May 27, 2014, the Partnership completed the private offering of $500 million 2.400% senior notes due 2019 (2019 Notes), $600 million 3.900% senior notes due 2024 (2024 Notes) and $550 million 5.000% senior notes due 2044 (2044 Notes), with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the $1.05 billion senior unsecured 2013 Term Loan Agreement, the EOIT $250 million variable rate term loan, the EOIT $200 million 6.875% senior notes due July 15, 2014 and for general corporate purposes. On July 15, 2014, the Partnership repaid the EOIT $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy guaranteed collection of the Partnership's obligations under the 2019 Notes and 2024 Notes. The guarantee expired on May 1, 2016. The 2019 Notes, 2024 Notes and 2044 Notes have a $1 million unamortized discount and $10 million of unamortized debt expense at December 31, 2016, resulting in effective interest rates of 2.59%, 4.02% and 5.09%, respectively, during the year ended December 31, 2016.

In connection with the issuance of the 2019 Notes, 2024 Notes and 2044 Notes, the Partnership, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers, entered into a registration rights agreement whereby the Partnership and the guarantor agreed to file with the SEC a registration statement relating to a registered offer to exchange the 2019 Notes, 2024 Notes and 2044 Notes for new series of the Partnership's notes in the same aggregate principal amount as, and with terms substantially identical in all respects to, the 2019 Notes, 2024 Notes and 2044 Notes. The agreement provided for the accrual of additional interest if the Partnership did not complete an exchange offer by October 9, 2015. Because an exchange offer was not consummated by October 9, 2015, additional interest began accruing on the 2019 Notes, 2024 Notes and 2044 Notes on October 10, 2015, at a rate of 0.25% per year until the first 90-day period after such date. On December 29, 2015, the Partnership completed the exchange offer. As a result, the Partnership recognized approximately $1 million of additional interest expense during 2015.

The indenture governing the 2019 Notes, 2024 Notes and 2044 Notes contains certain restrictions, including, among others, limitations on our ability and the ability of our principal subsidiaries to: (i) consolidate or merge and sell all or substantially all of our and our subsidiaries' assets and properties; (ii) create, or permit to be created or to exist, any lien upon any of our or our principal subsidiaries' principal property, or upon any shares of stock of any principal subsidiary, to secure any debt; and (iii) enter into certain sale-leaseback transactions. These covenants are subject to certain exceptions and qualifications.

As of December 31, 2016, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes have an $18 million unamortized premium at December 31, 2016, resulting in an effective interest rate of 3.83% during the year ended December 31, 2016. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

Financing Costs

Unamortized debt expense of $15 million and $18 million at December 31, 2016 and 2015, respectively, is classified as either a reduction to Long-Term Debt or Other Assets in the Consolidated Balance Sheets and is being amortized over the life of the respective debt. Unamortized premium, net of unamortized discount on long-term debt of $17 million and $23 million at December 31, 2016 and 2015, respectively, is classified as either Long-Term Debt or Short-Term Debt, consistent with the underlying debt instrument, in the Consolidated Balance Sheets and is being amortized over the life of the respective debt.

The Partnership recorded a $4 million loss on extinguishment of debt in the year ended December 31, 2014 associated with the retirement of the $1.05 billion 2013 Term Loan Agreement and the EOIT $250 million variable rate term loan, which is included in Other, net on the Consolidated Statements of Income.

As of December 31, 2016, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(11) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter WTI crude oil swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership's judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership's own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the period ended December 31, 2016, there were no transfers between Level 2 and Level 3 instruments.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, commercial paper and other such financial instruments on the Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership's financial instruments at December 31, 2016 and 2015:

	December 31, 2016		December 31, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Long-term notes payable—affiliated companies (Level 2)	$ —	$ —	$ 363	$ 350
Revolving Credit Facility (Level 2)[1]	636	636	310	310
2015 Term Loan Agreement (Level 2)	450	450	450	450
EOIT Senior Notes (Level 2)	268	260	273	280
Enable Midstream Partners, LP, 2019, 2024 and 2044 Notes (Level 2)	1,649	1,521	1,650	1,255

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. There was zero and $236 million of commercial paper outstanding as of December 31, 2016 and 2015, respectively.

The fair value of the Partnership's Long-term notes payable—affiliated companies, Revolving Credit Facility, and 2015 Term Loan Agreement, along with the EOIT Senior Notes and Enable Midstream Partners, LP, 2019, 2024 and 2044 Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

During the years ended December 31, 2016, 2015 and 2014, the Partnership remeasured the Service Star assets at fair value. At December 31, 2016, 2015 and 2014, management reassessed the carrying value of the Service Star business line, a component of the gathering and processing segment that provides measurement and communication services to third parties. The 2016 impairment, which impaired substantially all of the remaining net book value of the Service Star business line, was primarily driven by the impact of planned technology changes affecting Service Star. The 2015 impairment was based upon higher than expected losses of customers and the 2014 impairment was due to decreases of crude oil and natural gas prices. Based on forecasted future undiscounted cash flows management determined that the carrying value of the Service Star assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecasted cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the years ended December 31, 2016, 2015 and 2014, the Partnership recognized a $9 million, $10 million and $7 million impairment, respectively. The $9 million consisted of an $8 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The $10 million impairment consisted of a $9 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The $7 million impairment consisted of write-downs of property, plant and equipment.

At December 31, 2015, due to decreases of crude oil and natural gas prices during 2015, management reassessed the carrying value of the Partnership's investment in the Atoka assets, a component of the gathering and processing segment. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Atoka assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and intangible assets, the Partnership recognized a $25 million impairment during the year ended December 31, 2015. The $25 million impairment consisted of a $19 million write-down of property, plant and equipment and a $6 million write-down of intangible assets.

Additionally, during the year ended December 31, 2015, the Partnership recorded a $12 million impairment on jurisdictional pipelines in our transportation and storage segment.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2016 and 2015:

December 31, 2016	**Commodity Contracts**		**Gas Imbalances (1)**	
	Assets	**Liabilities**	**Assets (2)**	**Liabilities (3)**
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 2	$ 22	$ —	$ —
Significant other observable inputs (Level 2)	—	4	41	30
Unobservable inputs (Level 3)	—	8	—	—
Total fair value	2	34	41	30
Netting adjustments	—	—	—	—
Total	$ 2	$ 34	$ 41	$ 30

December 31, 2015	**Commodity Contracts**		**Gas Imbalances (1)**	
	Assets	**Liabilities**	**Assets (2)**	**Liabilities (3)**
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 17	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	10	—	17	20
Unobservable inputs (Level 3)	4	—	—	—
Total fair value	31	3	17	20
Netting adjustments	(3)	(3)	—	—
Total	$ 28	$ —	$ 17	$ 20

(1) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by EOIT are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of December 31, 2016 and 2015.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of zero and $6 million at December 31, 2016 and 2015, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $5 million at each of December 31, 2016 and 2015, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following tables provides a reconciliation of changes in the fair value of our Level 3 financial assets between the periods presented.

	Commodity Contracts	
	Crude oil (for condensate) financial futures/swaps	Natural gas liquids financial futures/swaps
	(In millions)	
Balance as of December 31, 2014	$ 5	$ —
Gains included in earnings	12	10
Settlements	(8)	(6)
Transfers out of Level 3[1]	(9)	—
Balance as of December 31, 2015	—	4
Losses included in earnings	—	(13)
Settlements	—	1
Transfers out of Level 3	—	—
Balance as of December 31, 2016	$ —	$ (8)

(1) The Partnership utilizes WTI crude oil swaps to manage exposure to condensate price risk. As the over-the-counter WTI crude oil swap is an active market, these derivative instruments were classified as Level 2 as of December 31, 2015.

Quantitative Information on Level 3 Fair Value Measurements

The Partnership utilizes the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

	December 31, 2016	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$ (8)	$0.385 - $0.936

(12) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price risk. The Partnership is also exposed to credit risk in its business operations.

Commodity Price Risk

The Partnership has used forward physical contracts, commodity price swap contracts and commodity price option features to manage the Partnership's commodity price risk exposures in the past. Commodity derivative instruments used by the Partnership are as follows:

- NGL put options, NGL futures and swaps, and WTI crude oil futures and swaps for condensate sales are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps are used to manage the Partnership's natural gas exposure associated with its gathering, processing and transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in Other Assets or Liabilities in the Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership's gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

As of December 31, 2016 and 2015, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may seek or be forced to enter into alternative arrangements. In that event, the Partnership's financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership's processing contracts, which are not derivative instruments.

As of December 31, 2016 and 2015, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	December 31, 2016		December 31, 2015	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas— TBtu(1)				
Financial fixed futures/swaps	2	29	1	37
Financial basis futures/swaps	2	30	4	38
Physical purchases/sales	1	25	2	51
Crude oil (for condensate)— MBbl(2)				
Financial futures/swaps	—	540	—	506
Natural gas liquids— MBbl(3)				
Financial futures/swaps	60	1,133	75	1,011

(1) As of December 31, 2016, 100% of the natural gas contracts have durations of one year or less. As of December 31, 2015, 97.7% of the natural gas contracts had durations of one year or less and 2.3% had durations of more than one year and less than two years.
(2) As of December 31, 2016 and 2015, 100% of the crude oil (for condensate) contracts have durations of one year or less.
(3) As of December 31, 2016 and 2015, 100% of the natural gas liquid contracts have durations of one year or less.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Consolidated Balance Sheet at December 31, 2016 and 2015 that were not designated as hedging instruments for accounting purposes are as follows:

		December 31, 2016		December 31, 2015	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$ 2	$ 22	$ 17	$ 3
Physical purchases/sales	Other Current	—	1	1	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current	—	3	9	—
Natural gas liquids					
Financial futures/swaps	Other Current	—	8	4	—
Total gross derivatives [1]		$ 2	$ 34	$ 31	$ 3

(1) See Note 11 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Consolidated Balance Sheets as of December 31, 2016 and 2015.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014:

	Amounts Recognized in Income		
	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Natural gas financial futures/swaps gains (losses)	$ (19)	$ 26	$ 37
Natural gas physical purchases/sales gains (losses)	(7)	(9)	1
Crude oil (for condensate) financial futures/swaps gains (losses)	(4)	12	9
Natural gas liquids financial futures/swaps gains (losses)	(13)	10	2
Total	$ (43)	$ 39	$ 49

For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2016, 2015 and 2014, if any, are reported in Product sales.

The following table presents the components of gain (loss) on derivative activity in the Partnership's Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Change in fair value of derivatives	$ (60)	$ (8)	$ 38
Realized gain on derivatives	17	47	11
Gain (loss) on derivative activity	$ (43)	$ 39	$ 49

Credit-Risk Related Contingent Features in Derivative Instruments

Based upon the Partnership's senior unsecured debt rating with Moody's Investors Services or Standard & Poor's Ratings Services, the Partnership could be required to provide credit assurances to third parties, which could include letters of credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position. As of December 31, 2016, under these obligations, $3 million of cash collateral has been posted. Based on positions as of December 31, 2016, there was no additional collateral required to be posted by the Partnership.

(13) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Year Ended December 31,		
	2016	2015	2014
		(In millions)	
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 105	$ 85	$ 77
Income taxes, net of refunds	—	1	1
Non-cash transactions:			
Accounts payable related to capital expenditures	18	52	93
Issuance of common units upon interest acquisition of SESH (Note 9)	—	1	161

The following table reconciles cash and cash equivalents and restricted cash on the Consolidated Balance Sheets to cash, cash equivalents and restricted cash on the Consolidated Statement of Cash Flows:

	2016
	(In millions)
Cash and cash equivalents	$ 6
Restricted cash	17
Cash, cash equivalents and restricted cash shown in the Consolidated Statement of Cash Flows	$ 23

(14) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides the following services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas: (1) firm transportation with seasonal contract demand, (2) firm storage, (3) no notice transportation with associated storage and (4) maximum rate firm transportation. The first three services are in effect through March 31, 2021, and will remain in effect from year to year thereafter unless either party provides 180 days' written notice prior to the contract termination date. The maximum rate firm transportation is in effect through March 31, 2018. MRT provides firm transportation and firm storage services to CenterPoint Energy's LDCs under agreements that are in effect through May 15, 2018, but will continue year to year thereafter unless either party provides twelve months' written notice prior to the contract termination date.

In 2015, EGT relocated a portion of its pipeline in Arkansas to improve reliability and increase capacity by constructing an approximately 28.5 mile new pipeline segment and abandoning approximately 34.2 miles of existing pipelines segments. In connection with the project, EGT sold an approximately 12.4 mile pipeline segment to CenterPoint Energy's Arkansas LDC for its remaining book value of $1 million, and EGT reimbursed CenterPoint Energy's Arkansas LDC approximately $7 million dollars for cost incurred in connecting the LDC to EGT's new pipeline segment.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to OGE Energy. On March 17, 2014, EOIT entered into a transportation agreement with OGE Energy, with a primary term of May 1, 2014 through April 30, 2019. Following the primary term, the agreement will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period.

On December 6, 2016, EOIT entered into a transportation agreement with OGE Energy, with a primary term expected to begin in late 2018 and extend for 20 years. In connection with the agreement, an approximately 80 mile pipeline will be built to serve OGE Energy's Muskogee Power Plant.

Gas Sales and Purchases Transactions

The Partnership sells natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchase natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. The Partnership enters into these physical natural gas transactions in the normal course of business based upon relevant market prices.

The Partnership's revenues from affiliated companies accounted for 7%, 7% and 6% of revenues during the years ended December 31, 2016, 2015 and 2014, respectively.

Amounts of revenues from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2016	2015	2014
		(In millions)	
Gas transportation and storage service revenue — CenterPoint Energy	$ 110	$ 110	$ 112
Natural gas product sales — CenterPoint Energy	1	7	22
Gas transportation and storage service revenue — OGE Energy	36	37	39
Natural gas product sales — OGE Energy	12	8	13
Total revenues — affiliated companies	$ 159	$ 162	$ 186

Amounts of natural gas purchased from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2016	2015	2014
		(In millions)	
Cost of natural gas purchases — CenterPoint Energy	$ —	$ 2	$ 2
Cost of natural gas purchases — OGE Energy	14	15	19
Total cost of natural gas purchases — affiliated companies	$ 14	$ 17	$ 21

Corporate services and seconded employee expense

For the year ended December 31, 2014, the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership reimbursed each of CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until the seconded employees transition from CenterPoint Energy and OGE Energy to the Partnership. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $6 million in 2016, $5 million in 2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

Under the terms of the MFA, the Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term that ended on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice prior to the end of any extension. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2016 are $7 million and $6 million, respectively.

On November 1, 2016, the Partnership entered into a new lease with an affiliate of CenterPoint Energy pursuant to which the Partnership leases office space in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and extends through December 31, 2019. The Partnership expects to incur approximately $3 million in rent and maintenance expenses through the end of the initial term of the lease. Prior to October 1, 2016, CenterPoint Energy provided the office space in Shreveport, Louisiana under the services agreement. As of December 31, 2016, CenterPoint Energy continues to provide office and data center space to the Partnership in Houston, Texas under the services agreement.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in Operation and maintenance expenses and General and administrative expenses in the Partnership's Consolidated Statements of Income are as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Seconded Employee Costs - CenterPoint Energy	$ —	$ —	$ 138
Corporate Services - CenterPoint Energy	6	15	29
Seconded Employee Costs - OGE Energy	29	35	105
Corporate Services - OGE Energy	5	11	17
Total corporate services and seconded employees expense	$ 40	$ 61	$ 289

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 5 for further discussion of the Series A Preferred Units.

Notes payable

The Partnership had outstanding long-term notes payable—affiliated companies to CenterPoint Energy at December 31, 2015 of $363 million, which were scheduled to mature in 2017. On February 18, 2016, in connection with the private placement of the Series A Preferred Units, the Partnership redeemed the $363 million of notes payable—affiliated companies payable to a subsidiary of CenterPoint Energy.

The Partnership recorded affiliated interest expense to CenterPoint Energy on note payable—affiliated companies of $1 million, $8 million and $8 million during the years ended December 31, 2016, 2015 and 2014, respectively.

(15) Commitments and Contingencies

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

	Year Ended December 31,						
	2017	2018	2019	2020	2021	After 2021	Total
	(In millions)						
Noncancellable operating leases	$ 10	$ 4	$ 3	$ —	$ —	$ —	$ 17

Total rental expense for all operating leases was $27 million, $32 million and $23 million during the years ended December 31, 2016, 2015 and 2014, respectively.

The Partnership currently occupies 162,053 square feet of office space at its executive offices under a lease that expires June 30, 2019. The lease payments are $19 million over the lease term, which began April 1, 2012. This lease has rent escalations which increase after 5 years, and will further escalate after 10 years if the lease is renewed. These lease expenses are included in General and administrative expense in the Consolidated Statements of Income.

The Partnership currently has 78 compression service agreements, of which 40 agreements are on a month-to-month basis, 32 agreements will expire in 2017 and 6 agreements will expire in 2018. The Partnership also has 6 gas treating lease agreements, all of which are on a month-to-month basis. These lease expenses are reflected in Operation and maintenance expense in the Consolidated Statements of Income.

Legal, Regulatory and Other Matters

The Partnership is involved in legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(16) Income Taxes

The Partnership's earnings are generally not subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries, Enable Midstream Services and Enable Muskogee Intrastate Transmission) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the consolidated financial statements. Consequently, the Consolidated Statements of Income do not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiaries).

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Provision (benefit) for current income taxes			
Federal	$ (1)	$ —	$ —
State	—	1	1
Total provision (benefit) for current income taxes	(1)	1	1
Provision (benefit) for deferred income taxes, net			
Federal	$ 3	—	$ —
State	(1)	(1)	1
Total provision (benefit) for deferred income taxes, net	2	(1)	1
Total income tax expense	$ 1	$ —	$ 2

The following schedule reconciles the statutory Federal income tax rate to the effective income tax rate:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Income (loss) before income taxes	$ 314	$ (771)	$ 535
Federal statutory rate	—%	—%	—%
Expected federal income tax expense	—	—	—
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	1	—	2
Total	1	—	2
Total income tax expense	$ 1	$ —	$ 2
Effective tax rate	0.3%	—%	0.4%

The components of Deferred Income Taxes as of December 31, 2016 and 2015 were as follows:

	December 31,	
	2016	2015
	(In millions)	
Deferred tax assets:	$ —	$ —
Deferred tax liabilities:		
Non-current:		
Depreciation	7	9
Other	3	(1)
Total non-current deferred tax liabilities	10	8
Accumulated deferred income taxes, net	$ 10	$ 8

Uncertain Income Tax Positions

There were no unrecognized tax benefits as of December 31, 2016, 2015 and 2014.

Tax Audits and Settlements

The federal income tax return of the Partnership has been audited through the 2013 tax year.

(17) Equity Based Compensation

Enable GP has adopted the Enable Midstream Partners, LP Long Term Incentive Plan (LTIP) for officers, directors and employees of the Partnership and its affiliates, including any individual who provides services to the Partnership as a seconded employee. The long-term incentive plan provides for the following types of awards: restricted units, phantom units, appreciations rights, option rights, cash incentive awards, performance units, distribution equivalent rights, and other awards denominated in, payable in, valued in or otherwise based on or related to common units.

The long-term incentive plan is administered by the Compensation Committee of the Board of Directors. With respect to any grant of equity as long-term incentive awards to our independent directors and our officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The long-term incentive plan limits the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled are available for delivery pursuant to other awards.

The Board of Directors may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made, including amending the long-term incentive plan to increase the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would be adverse to the participant without the consent of the participant.

The following table summarizes the Partnership’s equity based compensation expense for the years ended December 31, 2016, 2015 and 2014 related to performance units, restricted units and phantom units for the Partnership’s employees and independent directors:

	Year Ended December 31,		
	2016	2015	2014
	(In millions)		
Performance units	$ 9	$ 3	$ 3
Restricted units	3	7	10
Phantom units	1	1	2
Total compensation expense	$ 13	$ 11	$ 15

Performance Units

Awards of performance based phantom units (performance units) have been made under the LTIP in 2016, 2015 and 2014 to certain officers and employees providing services to the Partnership. Subject to the achievement of performance goals, the performance unit awards cliff vest three years from the grant date, with distribution equivalent rights paid at vesting. The performance goals for 2016, 2015 and 2014 awards are based on total unitholder return over a three calendar year performance cycle. Total unitholder return is based on the relative performance of the Partnership's common units against a peer group. The performance unit awards have a payout from 0% to 200% of the target based on the level of achievement of the performance goal. Performance units awards are paid out in common units, with distribution equivalent rights paid in cash at vesting. Any unearned performance units are cancelled. Pay out requires the confirmation of the achievement of the performance level by the Compensation Committee. Prior to vesting, performance units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. In the event of retirement, a participant will receive a pro rated payment based on the target performance, rather than actual performance, of the performance goals during the award cycle. Performance unit awards are classified as equity on the Partnership's Consolidated Balance Sheet.

The fair value of each performance unit award was estimated on the grant date using a lattice-based valuation model. The valuation information factored into the model includes the expected distribution yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition over the expected life of the performance units. Compensation expense for each performance unit award is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Distributions are accumulated and paid at vesting and, therefore, are included in the fair value calculation of the performance unit award. Due to the short trading history of the Partnership's common units, the expected price volatility for the awards granted in 2016 is based on two years of daily stock price observations, combined with the average of the one-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2015 is based on one year of daily stock price observations, combined with the average of the two-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2014 is based on the average of the two-year volatility of the applicable peer group companies used to determine the total unitholder return ranking. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Partnership's performance units. The number of performance units granted based on total unitholder return and the assumptions used to calculate the grant date fair value of the performance units based on total unitholder return are shown in the following table.

	2016	2015	2014
Number of units granted	1,235,429	501,474	563,963
Fair value of units granted	$10.42 - $27.77	$ 16.59	$ 29.61
Expected price volatility	43.2% - 46.0%	27.6%	22.2%
Risk-free interest rate	0.86% - 0.90%	0.99%	0.83%
Expected life of units (in years)	3.00	3.00	3.00

Phantom Units

Awards of phantom units have been made under the LTIP in 2016, 2015 and 2014 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. In 2014, 100,000 phantom units were awarded to certain officers and employees providing services to the Partnership that vested on the first anniversary of the grant date with distribution equivalent rights paid at vesting. Also in 2014, 6,718 phantom units were awarded to the independent directors for their service as directors that vested on the first anniversary of the grant date with distribution equivalent rights paid during the vesting period. In 2015, 9,817 phantom units were granted to employees providing services to the Partnership that vest on the first, second or third anniversary of the grant date with distribution equivalent rights paid during the vesting period. In April 2016, 653,286 phantom units were awarded to certain officers and employees providing services to the Partnership that vest on the first, second or third anniversary of the award with distribution equivalent rights paid during the vesting period. Phantom units awards are paid out in common units, with distributions equivalent rights paid in cash. Phantom units cliff-vest at the end of the vesting period. Any unearned phantom units are cancelled. Prior to vesting, phantom units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. Phantom unit awards are classified as equity on the Partnership's Consolidated Balance Sheet.

The fair value of the phantom units was based on the closing market price of the Partnership's common unit on the grant date. Compensation expense for the phantom unit is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over the vesting period. Distributions on phantom units are either accumulated and paid at vesting or paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the phantom unit is based on the applicable vesting period. The number of phantom units granted and the grant date fair value are shown in the following table.

	2016	2015	2014
Phantom units granted	653,286	9,817	106,718
Fair value of phantom units granted	$8.12 - $15.30	$ 12.70	$23.16 - $23.70

Restricted Units

Awards of restricted units were made under the LTIP in 2015 and 2014 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. These restricted unit awards cliff vest on the first, second, third or fourth anniversary of grant date, with distribution equivalent rights paid during the vesting period. Restricted units are outstanding and issued common units that cannot be sold, assigned, transferred or pledged by the recipient prior to vesting. Any unearned restricted units are cancelled. Prior to vesting, restricted units are subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control.

In 2014, 375,000 restricted units were granted to Lynn Bourdon, who was then the Chief Executive Officer of Enable GP, of which 40% vested on August 1, 2014, 20% vested on February 1, 2015 and 40% vested on July 15, 2015; 150,000 restricted units to Mr. Bourdon, of which 50% vested on May 29, 2015 and 50% was forfeited upon his departure; 137,500 restricted units were granted to Rodney J. Sailor, who was then the Chief Financial Officer of Enable GP, of which 45.46% vested on March 1, 2015 and 54.54% vested on March 1, 2016; 25,000 restricted units were granted to Mr. Sailor, which vest four years from the grant date; and 304,901 restricted units were granted to officers and employees providing services to the Partnership which vest on the first, second, third or fourth anniversary of grant date. In 2015, 279,677 restricted units were granted to officers and employees providing services to the Partnership which vest on the first, second, or third anniversary of grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture. Restricted unit awards are classified as equity on the Partnership's Consolidated Balance Sheet.

The fair value of the restricted units was based on the closing market price of the Partnership's common unit on the grant date. Compensation expense for the restricted units is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period, as defined in the agreements. Distributions are paid as declared prior to vesting and, therefore, are included in the fair value calculation. After payment, distributions are not subject to forfeiture. The expected life of the restricted units is based on the non-vested period since inception of the award cycle.

The number of restricted units granted related to the Partnership's employees and the grant date fair value are shown in the following table.

	2015	2014
Restricted units granted on April 16, 2014 to the Chief Executive Officer and Chief Financial Officer of Enable GP	—	687,500
Fair value of restricted units granted	$ —	$ 22.60
Restricted units granted to the Partnership's employees	279,677	304,901
Fair value of restricted units granted	$16.75 - $19.18	$23.56 - $25.50

Other Awards

In 2016 and 2015, the Board of Directors granted 14,914 and 17,384 common units, respectively, to the independent directors of Enable GP, for their service as directors, which vested immediately. The fair value of the common units were based on the closing market price of the Partnership's common unit on the grant date.

	2016	2015
Common units granted	14,914	17,384
Fair value of common units granted	$ 15.35	$ 11.12

Units Outstanding

A summary of the activity for the Partnership's performance units, restricted units and phantom units as of December 31, 2016 and changes during 2016 are shown in the following table.

	Performance Units		Restricted Stock		Phantom Units	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)					
Units Outstanding at 12/31/2015	814,510	$ 22.16	581,772	$ 21.04	9,817	$ 12.70
Granted(1)	1,235,429	10.80	—	—	653,286	8.45
Vested	(6,427)	20.77	(125,843)	22.78	(5,594)	12.44
Forfeited	(74,405)	15.94	(62,934)	19.43	(13,905)	8.12
Units Outstanding at 12/31/2016	1,969,107	15.27	392,995	20.74	643,604	8.49
Aggregate Intrinsic Value of Units Outstanding at 12/31/2016	$ 31		$ 6		$ 10	

(1) For performance units, this represents the target number of performance units granted. The actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

A summary of the Partnership's performance, restricted and phantom units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the year ended December 31, 2016 are shown in the following table.

	December 31, 2016		
	Performance Units	Restricted Stock	Phantom Units
	(In millions)		
Aggregate Intrinsic Value of Units Vested	$ —	$ 1	$ —
Fair Value of Units Vested	—	3	—

Unrecognized Compensation Cost

A summary of the Partnership's unrecognized compensation cost for its non-vested performance units, restricted units and phantom units, and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

	December 31, 2016	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 15	1.81
Restricted Units	2	1.12
Phantom Units	4	2.20
Total	$ 21	

As of December 31, 2016, there were 9,307,350 units available for issuance under the long term incentive plan.

(18) Reportable Segments

The Partnership's determination of reportable segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the reportable segments are the same as those described in the summary of significant accounting policies described in Note 1. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) transportation and storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily to natural gas producers, utilities and industrial customers.

Financial data for reportable segments are as follows:

Year Ended December 31, 2016	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$ 1,081	$ 479	$ (388)	$ 1,172
Service revenue	559	545	(4)	1,100
Total Revenues[2]	1,640	1,024	(392)	2,272
Cost of natural gas and natural gas liquids	915	492	(390)	1,017
Operation and maintenance, General and administrative	276	191	(2)	465
Depreciation and amortization	212	126	—	338
Impairments	9	—	—	9
Taxes other than income tax	32	26	—	58
Operating income	$ 196	$ 189	$ —	$ 385
Total assets	$ 7,453	$ 4,963	$ (1,204)	$ 11,212
Capital expenditures	$ 312	$ 71	$ —	$ 383

Year Ended December 31, 2015	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$ 1,118	$ 590	$ (374)	$ 1,334
Service revenue	545	542	(3)	1,084
Total Revenues[2]	1,663	1,132	(377)	2,418
Cost of natural gas and natural gas liquids	908	565	(376)	1,097
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating loss	$ (306)	$ (406)	$ —	$ (712)
Total assets	$ 7,536	$ 4,976	$ (1,286)	$ 11,226
Capital expenditures	$ 839	$ 110	$ —	$ 949

Year Ended December 31, 2014	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Product sales	$ 1,907	$ 1,009	$ (616)	$ 2,300
Service revenue	517	568	(18)	1,067
Total Revenues[2]	2,424	1,577	(634)	3,367
Cost of natural gas and natural gas liquids	1,585	961	(632)	1,914
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$ 349	$ 237	$ —	$ 586
Total Assets	$ 8,356	$ 5,493	$ (2,012)	$ 11,837
Capital expenditures	$ 740	$ 103	$ (6)	$ 837

(1) Equity in earnings of equity method affiliate is included in Other Income (Expense) on the Consolidated Statements of Income, and is not included in the table above. See Note 9 for discussion regarding ownership interest in SESH and related equity earnings included in the transportation and storage segment for the years ended December 31, 2016, 2015 and 2014.

(2) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 14 for revenues from affiliated companies.