Boardwalk Pipeline Partners, LP
Form 10-K
February 15, 2017
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K
(Mark One)
ý 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: 01-32665

BOARDWALK PIPELINE PARTNERS, LP
(Exact name of registrant as specified in its charter)
DELAWARE
(State or other jurisdiction of incorporation or organization)
20-3265614
(I.R.S. Employer Identification No.)
9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122
(Address and Telephone Number of Registrant's Principal Executive Office)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	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 ý No o

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

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 ý No o

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 ý No o

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. (Check one)
Large accelerated filer ý Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2016, was approximately $2.2 billion. As of February 15, 2017, the registrant had 250,296,782 common units outstanding.
Documents incorporated by reference. None.

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BOARDWALK PIPELINE PARTNERS, LP

PART I

Item 1. Business

Unless the context otherwise requires, references in this Report to “we,” “our,” “us” or like terms refer to the business of Boardwalk Pipeline Partners, LP and its consolidated subsidiaries.

Introduction

We are a Delaware limited partnership formed in 2005. Our business, which is conducted by our primary subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines) and its operating subsidiaries, as shown in the diagram below (together, the operating subsidiaries), consists of integrated natural gas and natural gas liquids and other hydrocarbons (herein referred to together as NGLs) pipeline and storage systems. All of our operations are conducted by the operating subsidiaries. Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 125.6 million of our common units and, through Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, our 2% general partner interest and all of our incentive distribution rights (IDRs). As of February 13, 2017, the common units and general partner interest owned by BPHC represent approximately 51% of our equity interests, excluding the IDRs. Our Partnership Interests, as described in Part II, Item 5 of this Report, contains more information on how we calculate BPHC’s equity ownership. Our common units are traded under the symbol “BWP” on the New York Stock Exchange (NYSE).

The following diagram reflects a simplified version of our current organizational structure:

Our Business

We are a master limited partnership operating in the midstream portion of the natural gas and NGLs industry, providing transportation and storage for those commodities. We own approximately 14,365 miles of natural gas and NGLs pipelines and underground storage caverns having aggregate capacity of approximately 205.0 billion cubic feet (Bcf) of working natural gas and 24.0 million barrels (MMBbls) of NGLs. Our natural gas pipeline systems are located in the Gulf Coast region, Oklahoma, Arkansas and the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio, and our NGLs pipelines and storage facilities are located in Louisiana and Texas.

We serve a broad mix of customers, including producers of natural gas, local distribution companies (LDCs), marketers, electric power generators, industrial users and interstate and intrastate pipelines. We provide a significant portion of our natural gas pipeline transportation and storage services through firm contracts under which our customers pay monthly capacity reservation fees, which are fees owed regardless of actual pipeline or storage capacity utilization. Other fees are based on actual utilization of the capacity under firm contracts and contracts for interruptible services. Contracts for our NGLs services are generally fee-based or based on minimum volume requirements, while others are dependent on actual volumes transported or stored. For the year ended December 31, 2016, approximately 81% of our revenues were derived from capacity reservation fees under firm contracts, approximately 12% of our revenues were derived from fees based on utilization under firm contracts and approximately 7% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL) and other services. Part II, Item 6 of this Report contains a summary of our revenues from external customers, net income and total assets, all of which were attributable to our pipeline and storage systems operating in one reportable segment.

The maximum rates we can charge for most of our natural gas transportation services, as well as the general terms and conditions of those services, are established by, and subject to review and revision by, the Federal Energy Regulatory Commission (FERC). These rates are based upon certain assumptions to allow us the opportunity to recover the cost of providing these services and earn a reasonable return on equity. However, it is possible that we may not recover all of our costs or earn a return. We are authorized to charge market-based rates for the majority of our natural gas storage capacity pursuant to authority granted by the FERC. The Surface Transportation Board (STB), a division of the United States (U.S.) Department of Transportation (DOT), has authority to regulate the rates we charge for service on certain of our ethylene pipelines, while the Louisiana Public Service Commission (LPSC) regulates the rates we charge for service on our other NGL pipelines. The STB and LPSC require that our transportation rates are reasonable and that our practices cannot unreasonably discriminate among our shippers.

Our Pipeline and Storage Systems

We own and operate approximately 13,930 miles of interconnected natural gas pipelines, directly serving customers in thirteen states and indirectly serving customers throughout the northeastern and southeastern U.S. through numerous interconnections with unaffiliated pipelines. We also own and operate more than 435 miles of NGLs pipelines in Louisiana and Texas. In 2016, our pipeline systems transported approximately 2.3 trillion cubic feet (Tcf) of natural gas and approximately 64.8 MMBbls of NGLs. Average daily throughput on our natural gas pipeline systems during 2016 was approximately 6.3 Bcf. Our natural gas storage facilities are comprised of fourteen underground storage fields located in four states with aggregate working gas capacity of approximately 205.0 Bcf and our NGLs storage facilities consist of nine salt-dome caverns located in Louisiana with an aggregate storage capacity of approximately 24.0 MMBbls. We also own three salt-dome caverns and a brine pond for use in providing brine supply services and to support the NGLs storage operations.

The principal sources of supply for our natural gas pipeline systems are regional supply hubs and market centers located in the Gulf Coast and Mid-Continent regions, including offshore Louisiana, the Perryville, Louisiana, area, the Henry Hub in Louisiana and the Carthage, Texas, area. Our pipelines in the Carthage, Texas, area provide access to natural gas supplies from the Barnett and Haynesville Shales and other natural gas producing regions in eastern Texas and northern Louisiana. The Henry Hub serves as the designated delivery point for natural gas futures contracts traded on the New York Mercantile Exchange. Our pipeline systems also have access to unconventional supplies such as the Woodford Shale in southeastern Oklahoma, the Fayetteville Shale in Arkansas, the Eagle Ford Shale in southern Texas and wellhead supplies in northern and southern Louisiana and Mississippi, and we also receive gas in the Lebanon, Ohio, area from the Marcellus and Utica Shales located in the northeastern U.S. Our NGLs pipeline systems access the Gulf Coast petrochemical industry through our operations at our Choctaw Hub in the Mississippi River corridor area of Louisiana and the Sulphur Hub in the Lake Charles, Louisiana, area. We also access ethylene supplies at Port Neches, Texas, which we deliver to petrochemical-industry customers in Louisiana.

The following is a summary of each of our principal operating subsidiaries:

Gulf South Pipeline Company, LP (Gulf South): Our Gulf South pipeline system is located along the Gulf Coast in the states of Texas, Louisiana, Mississippi, Alabama and Florida. The on-system markets directly served by the Gulf South system are generally located in eastern Texas, Louisiana, southern Mississippi, southern Alabama and the Florida Panhandle. These markets include LDCs and municipalities located across the system, including New Orleans, Louisiana; Jackson, Mississippi; Mobile, Alabama; and Pensacola, Florida, and other end-users located across the system, including the Baton Rouge to New Orleans industrial corridor and Lake Charles, Louisiana. Gulf South also has indirect access to off-system markets through numerous interconnections with unaffiliated interstate and intrastate pipelines and storage facilities. These pipeline interconnections provide access to markets throughout the northeastern and southeastern U.S.

Gulf South has ten natural gas storage facilities. The two natural gas storage facilities located in Bistineau, Louisiana, and Jackson, Mississippi, have approximately 83.5 Bcf of working gas storage capacity from which Gulf South offers firm and interruptible storage service, including no-notice service (NNS), and support pipeline operations. Gulf South also owns and operates eight high deliverability salt-dome natural gas storage caverns in Forrest County, Mississippi, having approximately 46.0 Bcf of total storage capacity, of which approximately 29.6 Bcf is working gas capacity, and owns undeveloped land which is suitable for up to five additional storage caverns.

Texas Gas Transmission, LLC (Texas Gas): Our Texas Gas pipeline system is located in Louisiana, East Texas, Arkansas, Mississippi, Tennessee, Kentucky, Indiana and Ohio, with smaller diameter lines extending into Illinois. Texas Gas directly serves LDCs, municipalities and power generators in its market area, which encompasses eight states in the South and Midwest and includes the Memphis, Tennessee; Louisville, Kentucky; Cincinnati and Dayton, Ohio; and Evansville and Indianapolis, Indiana, metropolitan areas. Texas Gas also has indirect market access to, and receives supply from, the Northeast through interconnections with unaffiliated pipelines. A large portion of the gas delivered by the Texas Gas system is used for heating during the winter months.

Texas Gas owns nine natural gas storage fields, of which it owns the majority of the working and base gas. Texas Gas uses this gas to meet the operational requirements of its transportation and storage customers and the requirements of its NNS customers. Texas Gas also uses its storage capacity to offer firm and interruptible storage services.

Gulf Crossing Pipeline Company LLC (Gulf Crossing): Our Gulf Crossing pipeline system is located near Sherman, Texas, and proceeds to the Perryville, Louisiana, area. The market areas are in the Midwest, Northeast and Southeast, including Florida, through interconnections with Gulf South, Texas Gas and unaffiliated pipelines.

Boardwalk Louisiana Midstream, LLC and Boardwalk Petrochemical Pipeline, LLC (collectively, Louisiana Midstream):
Louisiana Midstream provides transportation and storage services for natural gas, NGLs and ethylene, fractionation services for NGLs and brine supply services for producers and consumers of petrochemicals through two hubs in southern Louisiana - the Choctaw Hub in the Mississippi River Corridor area and the Sulphur Hub in the Lake Charles area. These assets provide approximately 71.4 MMBbls of salt-dome storage capacity, including approximately 7.6 Bcf of working natural gas storage capacity; significant brine supply infrastructure; and approximately 270 miles of pipeline assets, including an extensive ethylene distribution system. Louisiana Midstream also owns and operates the Evangeline Pipeline (Evangeline), an approximately 180-mile interstate ethylene pipeline that is capable of transporting approximately 2.6 billion pounds of ethylene per year between Port Neches, Texas, and Baton Rouge, Louisiana, where it interconnects with the ethylene distribution system and storage facilities at the Choctaw Hub. Throughput for Louisiana Midstream was 64.8 MMBbls for the year ended December 31, 2016.

Boardwalk Field Services, LLC (Field Services): Field Services operates natural gas gathering, compression, treating and processing infrastructure primarily in South Texas.

The following table provides information for our pipeline and storage systems as of February 15, 2017:
Pipeline and Storage Systems

	Miles of Pipeline	Working Gas Storage Capacity (Bcf)	Liquids Storage Capacity (MMBbls)	Peak-day Delivery Capacity (Bcf/d) (1)	Average Daily Throughput (Bcf/d) (1)
Gulf South	7,225	113.1	—	8.3	2.7
Texas Gas	6,025	84.3	—	5.2	2.4
Gulf Crossing	375	—	—	1.9	1.1
Louisiana Midstream	450	7.6	24.0	—	—
Field Services	290	—	—	—	0.1

(1) Bcf per day (Bcf/d)

Current Growth Projects

In response to changes in the natural gas industry and growth in the petrochemical industry, we are currently engaged in several growth projects, which are described below. Several of our growth projects were placed into service in 2016, including the Ohio to Louisiana Access project, the Southern Indiana Lateral, the Western Kentucky Market Lateral and a power plant project in South Texas. These projects were completed on time at an aggregate cost which was approximately $30.0 million lower than the $350.0 million originally estimated. The estimated total costs of our remaining growth projects are expected to be approximately as follows (in millions):

	Estimated Total Cost(1)	Expected in-service date(1)	Approximate weighted-average contract life (in years)
Northern Supply Access	$ 230.0	Second quarter 2017	16
Sulphur Storage and Pipeline Expansion	145.0	Fourth quarter 2017	Confidential
Coastal Bend Header	720.0	First half 2018	20
Other growth projects (2)	170.0	Second half 2017-2019	Various

(1) Estimates are based on internally developed financial models and time-lines. Factors in the estimates include, but are not limited to, those related to pipeline costs based on mileage, size and type of pipe, materials and construction and engineering costs.

(2) Other growth projects consist of projects in Louisiana comprised of three ethylene transportation and storage projects to serve industrial customers, the development of storage wells and associated facilities for brine supply services and a natural gas transportation project to serve a power plant. The power plant project remains subject to customer and FERC approvals.

Refer to Liquidity and Capital Resources in Part II, Item 7 of this Report for further discussion of capital expenditures and financing.

Northern Supply Access Project: Our Northern Supply Access project will increase the peak-day transmission capacity on our Texas Gas system by the addition of compression facilities and other system modifications to make this portion of the system bi-directional. This project is supported by precedent agreements for approximately 0.3 Bcf/d of peak-day transmission capacity.

Sulphur Storage and Pipeline Expansion Project: We executed a long-term agreement to provide liquids transportation and storage services to support the development of a new ethane cracker plant in the Lake Charles, Louisiana, area. The project will involve significant storage and infrastructure development to serve petrochemical customers near our Sulphur Hub.

Coastal Bend Header Project: This project is supported by precedent agreements with foundation shippers to transport natural gas to serve a planned liquefied natural gas (LNG) liquefaction terminal in Freeport, Texas. As part of the project, we will construct an approximately 65-mile pipeline supply header with an approximate 1.4 Bcf/d of capacity to serve the terminal. Additionally, we will expand and modify our existing Gulf South pipeline facilities that will provide access to additional supply sources through various interconnects in South Texas and in the Louisiana area.

Nature of Contracts

We contract with our customers to provide transportation and storage services on a firm and interruptible basis. We also provide bundled firm transportation and storage services, which we provide to our natural gas customers as NNS, interruptible PAL services for our natural gas customers, gathering and processing services for our natural gas customers and brine supply services for certain petrochemical customers and fractionation services.

Transportation Services: We offer natural gas transportation services on both a firm and interruptible basis. Our natural gas customers choose, based upon their particular needs, the applicable mix of services depending upon availability of pipeline capacity, the price of services and the volume and timing of customer requirements. Our natural gas firm transportation customers reserve a specific amount of pipeline capacity at specified receipt and delivery points on our system. Firm natural gas customers generally pay fees based on the quantity of capacity reserved regardless of use, plus a commodity and a fuel charge paid on the volume of natural gas actually transported. Capacity reservation revenues derived from a firm service contract are generally consistent during the contract term, but can be higher in winter periods than the rest of the year, especially for NNS agreements.

Firm transportation contracts generally range in term from one to twenty years, although we may enter into shorter- or longer-term contracts. In providing interruptible natural gas transportation service, we agree to transport natural gas for a customer when capacity is available. Interruptible natural gas transportation service customers pay a commodity charge only for the volume of gas actually transported, plus a fuel charge. Interruptible transportation agreements have terms ranging from day-to-day to multiple years, with rates that change on a daily, monthly or seasonal basis. Our NGLs transportation services are generally fee-based or based on minimum volume requirements.

Storage Services: We offer natural gas storage services on both a firm and interruptible basis. Firm storage customers reserve a specific amount of storage capacity, including injection and withdrawal rights, while interruptible customers receive storage capacity and injection and withdrawal rights when available. Similar to firm transportation customers, firm storage customers generally pay fees based on the quantity of capacity reserved plus an injection and withdrawal fee. Firm storage contracts typically range in term from one to ten years. Interruptible storage customers pay for the volume of gas actually stored plus injection and withdrawal fees. Generally, interruptible storage agreements are for monthly terms. We are able to charge market-based rates for the majority of our natural gas storage capacity pursuant to authority granted by the FERC. Our NGLs storage rates are market-based, and the contracts for NGLs services are typically fixed-price arrangements with escalation clauses.

No-Notice Services: NNS consist of a combination of firm natural gas transportation and storage services that allow customers to inject or withdraw natural gas from storage with little or no notice. Customers pay a reservation charge based upon the capacity reserved plus a commodity and a fuel charge based on the volume of gas actually transported. In accordance with its tariff, Texas Gas loans stored gas to certain of its no-notice customers who are obligated to repay the gas in-kind.

Parking and Lending Service: PAL is an interruptible service offered to customers providing them the ability to park (inject) or borrow (withdraw) natural gas into or out of our pipeline systems at a specific location for a specific period of time. Customers pay for PAL services in advance or on a monthly basis depending on the terms of the agreement.

Customers and Markets Served

We contract directly with producers of natural gas and with end-use customers, including LDCs, marketers, electric power generators, industrial users and interstate and intrastate pipelines, who, in turn, provide transportation and storage services for end-users. Based on our 2016 transportation, storage and PAL revenues, net of fuel, our customer mix was as follows: natural gas producers (46%), power generators (18%), LDCs (16%), marketers (14%) and industrial end-users and others (6%). Based upon our 2016 transportation, storage and PAL revenues, net of fuel, our deliveries were as follows: pipeline interconnects (50%), LDCs (18%), industrial end-users (10%), power generators (10%), storage activities (9%) and others (3%). No customer comprises 10% or more of our 2016 operating revenues.

Natural Gas Producers: Producers of natural gas use our services to transport gas supplies from producing areas, including shale natural gas production areas, to supply pools and to other customers on and off of our systems. Producers contract with us for storage services to store excess production and to optimize the ultimate sales prices for their gas.

Power Generators: Our natural gas pipelines are directly connected to 47 natural-gas-fired power generation facilities in nine states. The demand of the power generating customers generally peaks during the summer cooling season which is counter to the winter season peak demands of the LDCs, although recently we have begun to see an increase in demand from power generators in the winter months as well, due to the overall increase in the use of natural gas over other sources such as coal to generate electricity. Our power-generating customers can use a combination of no-notice, firm and interruptible transportation services.

Local Distribution Companies: Most of our LDC customers use firm natural gas transportation services, including NNS. We serve approximately 168 LDCs at more than 300 delivery locations across our pipeline systems. The demand of these customers peaks during the winter heating season.

Marketers: Natural gas marketing companies utilize our services to provide services to our other customer groups as well as to customer groups in off-system markets. The services may include combined gas transportation and storage services to support the needs of the other customer groups. Some of the marketers are sponsored by LDCs or producers.

Industrial End-Users: We provide approximately 190 industrial facilities with a combination of firm and interruptible natural gas and NGLs transportation and storage services. Our pipeline systems are directly connected to industrial facilities in the Baton Rouge to New Orleans industrial corridor; Lake Charles, Louisiana; Mobile, Alabama; and Pensacola, Florida. We can also access the Houston Ship Channel through third-party natural gas pipelines.

Competition

We compete with numerous other pipelines that provide transportation, storage and other services at many locations along our pipeline systems. We also compete with pipelines that are attached to natural gas supply sources that are closer to some of our traditional natural gas market areas. In addition, regulators' continuing efforts to increase competition in the natural gas industry have increased the natural gas transportation options of our traditional customers. For example, as a result of regulators' policies, capacity segmentation and capacity release have created an active secondary market which increasingly competes with our own natural gas pipeline services. Further, natural gas competes with other forms of energy available to our customers, including electricity, coal, fuel oils and other alternative fuel sources.

The principal elements of competition among pipelines are availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. In many cases, the elements of competition, in particular flexibility, terms of service and reliability, are key differentiating factors between competitors. This is especially the case with capacity being sold on a longer-term basis. We are focused on finding opportunities to enhance our competitive profile in these areas by increasing the flexibility of our pipeline systems, such as modifying them to allow for bi-directional flows, to meet the demands of customers such as power generators and industrial users, and are continually reviewing our services and terms of service to offer customers enhanced service options.

Seasonality

Our revenues can be affected by weather, natural gas price levels, gas price differentials between locations on our pipeline systems (basis spreads), gas price differentials between time periods, such as winter to summer (time period price spreads), and natural gas price volatility. Weather impacts natural gas demand for heating needs and power generation, which in turn influences the short-term value of transportation and storage across our pipeline systems. Colder than normal winters can result in an increase in the demand for natural gas for heating needs and warmer than normal summers can impact cooling needs, both of which typically result in increased pipeline transportation revenues and throughput. While traditionally peak demand for natural gas occurs during the winter months driven by heating needs, the increased use of natural gas for cooling needs during the summer months has partially reduced the seasonality of our revenues. During 2016, approximately 53% of our operating revenues were recognized in the first and fourth quarters of the year.

Government Regulation

Federal Energy Regulatory Commission: The FERC regulates our natural gas operating subsidiaries under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. The FERC regulates, among other things, the rates and charges for the transportation and storage of natural gas in interstate commerce and the extension, enlargement or abandonment of facilities under its jurisdiction. Where required, our interstate natural gas pipeline subsidiaries hold certificates of public convenience and necessity issued by the FERC covering certain of their facilities, activities and services. The FERC also prescribes accounting treatment for our interstate natural gas pipeline subsidiaries which is separately reported pursuant to forms filed with the FERC. The regulatory books and records and other activities of our subsidiaries that operate under the FERC's jurisdiction may be periodically audited by the FERC.

The maximum rates that may be charged by our operating subsidiaries that operate under the FERC's jurisdiction for all aspects of the natural gas transportation services they provide are established through the FERC's cost-of-service rate-making process. Key determinants in the FERC's cost-of-service rate-making process are the costs of providing service, the volumes of gas being transported, the rate design, the allocation of costs between services, the capital structure and the rate of return a pipeline is permitted to earn. The maximum rates that may be charged by us for storage services on Texas Gas, with the exception of services associated with a portion of the working gas capacity on that system, are also established through the FERC's cost-of-service rate-making process. The FERC has authorized us to charge market-based rates for firm and interruptible storage services for the majority of our natural gas storage facilities. None of our FERC-regulated entities has an obligation to file a new rate case, and Gulf South is prohibited from filing a rate case until May 1, 2023, subject to certain exceptions.

U.S. Department of Transportation: We are regulated by DOT, through the Pipeline and Hazardous Material Safety Administration (PHMSA), under the Natural Gas Pipeline Safety Act of 1968, as amended (NGPSA), and the Hazardous Liquids Pipeline Safety Act of 1979, as amended (HLPSA). The NGPSA and HLPSA govern the design, installation, testing, construction, operation, replacement and management of interstate natural gas and NGLs pipeline facilities. We have received authority from PHMSA to operate certain natural gas pipeline assets under special permits that will allow us to operate those pipeline assets at higher than normal operating pressures of up to 0.80 of the pipe's Specified Minimum Yield Strength (SMYS). Operating at higher than normal operating pressures will allow us to transport all of the volumes we have contracted for with our customers. PHMSA retains discretion whether to grant or maintain authority for us to operate our natural gas pipeline assets at higher pressures. PHMSA has also developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain high risk areas, known as high consequence areas (HCAs), along our pipelines and take additional measures to protect pipeline segments located in those areas, including highly populated areas. The NGPSA and HLPSA were most recently amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 (2011 Act) in 2012. The 2011 Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. More recently, in June 2016, the NGPSA and HLPSA were amended by the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 (2016 Act), extending PHMSA’s statutory mandate through 2019 and, among other things, requiring PHMSA to complete certain of its outstanding mandates under the 2011 Act and developing new safety standards for natural gas storage facilities by June 22, 2018. The 2016 Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of gas or hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property or the environment.

Surface Transportation Board and Louisiana Public Service Commission: The STB has authority to regulate the rates we charge for service on certain of our ethylene pipelines, while the LPSC regulates the rates we charge for service on our other NGL pipelines. The STB and LPSC require that our transportation rates are reasonable and that our practices cannot unreasonably discriminate among our shippers.

Other: Our operations are also subject to extensive federal, state and local laws and regulations relating to protection of the environment. Such laws and regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases, discharges and emissions of various substances into the environment. Environmental regulations also require that our facilities, sites and other properties be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. The laws, as amended from time to time, that our operations are subject to include, for example:

- the Clean Air Act (CAA) and analogous state laws, which impose obligations related to air emission pollutants, greenhouse gas (GHG) emissions and regulations affecting reciprocating engines subject to Maximum Achievable Control Technology standards;
- the Federal Water Pollution Control Act, commonly referred to as the Clean Water Act, and analogous state laws, which regulate discharge of wastewater from our facilities into state and federal waters;
- the Comprehensive Environmental Response, Compensation and Liability Act, commonly referred to as CERCLA, or the Superfund law, and analogous state laws, which regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or locations to which we have sent wastes for disposal;
- the Resource Conservation and Recovery Act and analogous state laws, which impose requirements for the handling and discharge of solid and hazardous waste from our facilities; and
- the Occupational Safety and Health Act (OSHA) and analogous state laws, which establish workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances and appropriate control measures.

Many states where we operate also have, or are developing, similar environmental or occupational health and safety legal requirements governing many of the same types of activities and those requirements can be more stringent than those adopted under federal laws and regulations. Failure to comply with these federal, state and local laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations, the occurrence of delays in the development or expansion of projects and the issuance of orders enjoining performance of some or all of our operations in affected areas. Historically, our environmental compliance costs have not had a material adverse effect on our results of operations, but there can be no assurance that continued compliance with existing requirements will not materially affect us or that the current regulatory standards will not become more onerous in the future, resulting in more significant costs to maintain compliance or increased exposure to significant liabilities, which could diminish our ability to make distributions to our unitholders.

Effects of Compliance with Environmental Regulations

Note 4 in Part II, Item 8 of this Report contains information regarding environmental compliance.

Employee Relations

At December 31, 2016, we had approximately 1,280 employees, approximately 110 of whom are included in collective bargaining units. A satisfactory relationship exists between management and labor. We maintain various defined contribution plans covering substantially all of our employees and various other plans which provide regular active employees with medical, life and disability coverage. We also have a non-contributory, defined benefit pension plan and a postretirement medical plan which covers Texas Gas employees hired prior to certain dates. Note 11 in Part II, Item 8 of this Report contains further information regarding our employee benefits.

Available Information

Our website is located at www.bwpmlp.com. We make available free of charge through our website our Annual Reports on Form 10-K, which include our audited financial statements, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (Exchange Act) as soon as we electronically file such material with the Securities and Exchange Commission (SEC). These documents are also available at the SEC's Public Reference Room at 100 F Street, NE, Washington, District of Columbia 20549 or at the SEC's website at www.sec.gov. You can obtain additional information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Additionally, copies of these documents, excluding exhibits, may be requested at no cost by contacting Investor Relations, Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046.

We also make available within the “Governance” section of our website our corporate governance guidelines, the charter of our Audit Committee and our Code of Business Conduct and Ethics. Requests for copies may be directed in writing to: Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046, Attention: Corporate Secretary.

Interested parties may contact the chairpersons of any of our Board committees, our Board’s independent directors as a group or our full Board in writing by mail to Boardwalk Pipeline Partners, LP, 9 Greenway Plaza, Suite 2800, Houston, TX 77046, Attention: Corporate Secretary. All such communications will be delivered to the director or directors to whom they are addressed.

Item 1A. Risk Factors

Our business faces many risks and uncertainties. We have described below the most significant risks facing us. These risks and uncertainties could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations or cash flows, including our ability to make distributions to our unitholders.

All of the information included in this Report and any subsequent reports we may file with the SEC or make available to the public should be carefully considered and evaluated before investing in any securities issued by us.

Business Risks

We may not be able to replace expiring natural gas transportation contracts at attractive rates or on a long-term basis and may not be able to sell short-term services at attractive rates or at all due to market conditions.

Each year, a portion of our firm natural gas transportation contracts expire and need to be renewed or replaced. Over the past several years, we have renewed some expiring contracts at lower rates and for shorter terms than in the past, and in some cases we remarketed the capacity to other customers. We expect this trend to continue, including for the contracts we entered into in 2008 and 2009 related to our East Texas Pipeline, Southeast Expansion, Gulf Crossing Pipeline, and Fayetteville and Greenville Lateral growth projects. These projects are supported by firm transportation agreements, typically having a term of ten years and priced based on then current market conditions. As the terms of these contracts expire in 2018 and 2019, we will have significantly more transportation contract expirations than we have had during the past several years. We cannot predict what market conditions will prevail when these contracts expire. If these contracts are renewed, we expect that the new contracts will be at lower rates and for shorter contract terms than our current contracts. If these contracts are renewed at current market rates, the revenues earned from these transportation contracts would be materially lower than they are today.

The narrowing of the price differentials between natural gas supplies and market demand for natural gas has reduced the transportation rates that we can charge.

The transportation rates we are able to charge customers are heavily influenced by market trends (both short and longer term), including the available supply, geographical location of natural gas production, the competition between producing basins, the demand for gas by end-users such as power plants, petrochemical facilities and LNG export facilities and the price differentials between the gas supplies and the market demand for the gas (basis differentials). Current market conditions have resulted in a sustained narrowing of basis differentials on certain portions of our pipeline system, which has reduced transportation rates that can be charged in the affected areas and adversely affected the contract terms we can secure from our customers for available transportation capacity and for contracts being renewed or replaced. The prevailing market conditions may also lead some of our customers to seek to renegotiate existing contracts to terms that are less attractive to us; for example, seeking a current price reduction in exchange for an extension of the contract term. We expect these market conditions to continue.

We are exposed to credit risk relating to default or bankruptcy by our customers.

Credit risk relates to the risk of loss resulting from the default by a customer of its contractual obligations or the customer filing bankruptcy. We have credit risk with both our existing customers and those supporting our growth projects.

Natural gas producers comprise a significant portion of our revenues and support several of our growth projects. In 2016, approximately 46% of our revenues were generated from contracts with natural gas producers. For existing customers on our interstate pipelines, our FERC gas tariffs only allow us to require limited credit support. During

2016, the prices of oil and natural gas remained volatile. If gas prices continue to remain volatile for a sustained period of time, our producer customers will be adversely affected, which could lead some customers to default on their obligations to us or file for bankruptcy.

Credit risk also exists in relation to our growth projects, both because the foundation customers make long-term firm capacity commitments to us for such projects and certain of those foundation customers agree to provide credit support as construction for such projects progresses. If a customer fails to post the required credit support during the growth project process, overall returns on the project may be reduced to the extent an adjustment to the scope of the project results or we are unable to replace the defaulting customer.

Our credit exposure also includes receivables for services provided, future performance under firm agreements and volumes of gas owed by customers for imbalances or gas loaned by us to them under certain NNS and PAL services.

In 2016, the credit ratings of several of our producer customers, including some of those supporting our growth projects, were downgraded. The downgrades may restrict liquidity for those customers and indicate a greater likelihood of nonperformance of their contractual obligations, including failure to make future payments, or the failure to post required letters of credit or other forms of credit support. In addition, our customers that file for bankruptcy protection may also seek to have their contracts with us rejected in the bankruptcy proceedings. During 2016, several of our customers declared bankruptcy. While the overall impact of these bankruptcies was not material to our 2016 financial performance, one of the bankruptcies did negatively affect one of our growth projects.

We rely on a limited number of customers for a significant portion of revenues.

For 2016, while no customer comprised 10% or more of our operating revenues, our top ten customers comprised approximately 42% of our revenues. If any of our significant customers have credit or financial problems which result in bankruptcy, a delay or failure to pay for services provided by us, to post the required credit support for construction associated with our growth projects or existing contracts or to repay the gas they owe us, it could have a material adverse effect on our revenues.

Our actual construction and development costs could exceed our forecasts, our anticipated cash flow from construction and development projects will not be immediate and our construction and development projects may not be completed on time or at all.

We are engaged in multiple significant construction projects involving our existing assets and the construction of new facilities for which we have expended or will expend significant capital. We expect to continue to engage in the construction of additional growth projects and modifications of our system. When we build a new pipeline or expand or modify an existing facility, the design, construction and development occurs over an extended period of time, and we will not receive any revenue or cash flow from that project until after it is placed in service. Typically, there are several years between when the project is announced and when customers begin using the new facilities. During this period we spend capital and incur costs without receiving any of the financial benefits associated with the projects. The construction of new assets involves regulatory, environmental, activist, legal, political, materials and labor costs, as well as operational and other risks that are difficult to predict and beyond our control. Any of these projects may not be completed on time or at all due to a variety of factors, may be impacted by significant cost overruns or may be materially changed prior to completion as a result of developments or circumstances that we are not aware of when we commit to the project, including the inability of any shipper to provide adequate credit support or to otherwise perform their obligations under any precedent agreements. Any of these events could result in material unexpected costs or have a material adverse effect on our ability to realize the anticipated benefits from our growth projects.

Legislative and regulatory initiatives relating to pipeline safety that require the use of new or more prescriptive compliance activities, substantial changes to existing integrity management programs, or withdrawal of regulatory waivers could subject us to increased capital and operating costs and operational delays.

Our interstate pipelines are subject to regulation by PHMSA which is part of DOT. PHMSA regulates the design, installation, testing, construction, operation, replacement and management of existing interstate natural gas and NGLs pipeline facilities. PHMSA regulation currently requires pipeline operators to implement integrity management programs, including frequent inspections, correction of certain identified anomalies and other measures to promote pipeline safety in HCAs, such as high population areas, areas unusually sensitive to environmental damage and commercially navigable waterways. States have jurisdiction over certain of our intrastate pipelines and have adopted regulations similar to existing PHMSA regulations. State regulations may impose more stringent requirements than found under federal law. Compliance with these rules has resulted in an overall increase in our maintenance costs. PHMSA has issued notices of proposed rulemaking in April 2015 and March 2016, which have proposed new, more prescriptive regulations related to the overall operations of our interstate natural gas and NGLs pipelines which, if adopted as proposed, will cause us to incur increased capital and operating costs, experience operational delays, and result in potential adverse impacts to our ability to reliably serve our customers. Additionally, requirements that are imposed under the 2011 Act and 2016 Act may also increase our capital and operating costs or impact the operation of our pipeline.

We have entered into firm transportation contracts with shippers on certain of our expansion projects that utilize the design capacity of certain of our pipeline assets, based upon the authority we received from PHMSA to operate those pipelines at higher than normal operating pressures of up to 0.80 of the pipeline's SMYS. PHMSA retains discretion to withdraw or modify this authority. If PHMSA were to withdraw or materially modify such authority, it could affect our ability to transport all of our contracted quantities of natural gas on these pipeline assets and we could incur significant additional costs to reinstate this authority or to develop alternate ways to meet our contractual obligations.

Changes in energy prices, including natural gas, oil and NGLs, impact the supply of and demand for those commodities, which impact our business.

Our customers, especially producers, are directly impacted by changes in commodity prices. The prices of natural gas, oil and NGLs fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors. The declines in the levels of natural gas, oil and NGLs prices experienced in 2015 and 2016 have adversely affected the businesses of our producer customers and reduced the demand for our services and could result in defaults or the non-renewal of our contracted capacity when existing contracts expire. Future increases in the price of natural gas and NGLs could make alternative energy and feedstock sources more competitive and reduce demand for natural gas and NGLs. A reduced level of demand for natural gas and NGLs could reduce the utilization of capacity on our systems and reduce the demand for our services.

Our revolving credit facility contains operating and financial covenants that restrict our business and financing activities.

Our revolving credit facility contains operating and financial covenants that may restrict our ability to finance future operations or capital needs or to expand or pursue business activities. Our credit agreement limits our ability to make loans or investments, make material changes to the nature of our business, merge, consolidate or engage in asset sales, or grant liens or make negative pledges. This agreement also requires us to maintain a ratio of consolidated debt to consolidated EBITDA (as defined in the agreement) of not more than 5.0 to 1.0, or up to 5.5 to 1.0 for the three quarters following an acquisition, which limits the amount of additional indebtedness we can incur to grow our business, and could require us to reduce indebtedness if our earnings before interest, income taxes, depreciation and amortization (EBITDA) decreases to a level that would cause us to breach this covenant. Future financing agreements we may enter into could contain similar or more restrictive covenants or may not be as favorable as those under our existing indebtedness.

Our ability to comply with the covenants and restrictions contained in our credit agreement may be affected by events beyond our control, including economic, financial and market conditions. If market, economic conditions or our financial performance deteriorate, our ability to comply with these covenants may be impaired. If we are not able to incur additional indebtedness we may need to sell additional equity securities to raise needed capital, which could be dilutive to our existing equity holders, or to seek other sources of funding that may be on less favorable terms. If we default under our credit agreement or another financing agreement, significant additional restrictions may become applicable, including a restriction on our ability to make distributions to unitholders. In addition, a default could result in a significant portion of our indebtedness becoming immediately due and payable, and our lenders could terminate their commitment to make further loans to us. If such event occurs, we would not have, and may not be able to obtain, sufficient funds to make these accelerated payments.

A significant portion of our debt will mature over the next five years and will need to be paid or refinanced and changes to the debt and equity markets could adversely affect our business.

A significant portion of our debt is set to mature in the next five years, including our revolving credit facility. We may not be able to refinance our maturing debt on commercially reasonable terms, or at all, depending on numerous factors, including our financial condition and prospects at the time and the then current state of the banking and capital markets in the U.S.

Limited access to the debt and equity markets could adversely affect our business.

Our current strategy is to fund our announced growth projects through currently available financing options, including utilizing cash generated from operations, borrowings under our revolving credit facility, accessing proceeds from our

Subordinated Loan Agreement with BPHC (Subordinated Loan) and accessing the capital markets. Changes in the debt and equity markets, including market disruptions, limited liquidity, and interest rate volatility, may increase the cost of financing as well as the risks of refinancing maturing debt. Instability in the financial markets may increase our cost of capital while reducing the availability of funds. This may affect our ability to raise capital and reduce the amount of cash available to fund our operations or growth projects. If the debt and equity markets were not available, it is not certain if other adequate financing options would be available to us on terms and conditions that we would find acceptable.

Any disruption in the capital markets could require us to take additional measures to conserve cash until the markets stabilize or until we can arrange alternative credit arrangements or other funding for our business needs. Such measures could include reducing or delaying business activities, reducing our operations to lower expenses and reducing other discretionary uses of cash. We may be unable to execute our growth strategy or take advantage of certain business opportunities, any of which could negatively impact our business.

Climate change legislation and regulations restricting emissions of GHGs could result in increased operating and capital costs and reduced demand for our pipeline and storage services.

Climate change continues to attract considerable public and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. While no comprehensive climate change legislation has been implemented at the federal level, the Environmental Protection Agency (EPA) and states or groupings of states have pursued legal initiatives in recent years that seek to reduce GHG emissions through efforts that include consideration of cap-and-trade programs, carbon taxes and GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources.

In particular, the EPA has adopted rules that, among other things, establish certain permit reviews for GHG emissions from certain large stationary sources, which reviews could require securing permits at covered facilities emitting GHGs and meeting defined technological standards for those GHG emissions. The EPA has also adopted rules requiring the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore processing, transmission, storage and distribution facilities as well as gathering, compression and boosting facilities and blowdowns of natural gas transmission pipelines.

Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and natural gas operations. In June 2016, the EPA published regulations requiring certain new, modified or reconstructed facilities in the oil and natural gas sector to reduce these methane gas and volatile organic compound emissions and, in November 2016, the EPA began seeking additional information on methane emissions from certain existing facilities and operations in the oil and natural gas sector that could be developed into federal guidelines that states must consider in developing their own rules for regulating sources within their borders. In December 2015, the U.S. joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that prepared an agreement requiring member countries to review and “represent a progression” in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. This “Paris Agreement” was signed by the U.S. in April 2016 and entered into force in November 2016; however this agreement does not create any binding obligations for nations to limit their GHG emissions, but rather includes pledges to voluntarily limit or reduce future emissions.

The adoption and implementation of any international, federal or state legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs could result in increased compliance costs or additional operating restrictions. Finally, some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climate events.

Our natural gas transportation and storage operations are subject to extensive regulation by the FERC, including rules and regulations related to the rates we can charge for our services and our ability to construct or abandon facilities. The FERC's rate-making policies could limit our ability to recover the full cost of operating our pipelines, including earning a reasonable return.

Our natural gas transportation and storage operations are subject to extensive regulation by the FERC, including the types and terms of services we may offer to our customers, construction of new facilities, creation, modification or abandonment of services or facilities, recordkeeping and relationships with affiliated companies. An adverse FERC action in any of these areas could affect our ability to compete for business, construct new facilities, offer new services or recover the full cost of operating our pipelines. This regulatory oversight can result in longer lead times to develop and complete any future project than competitors that are not subject to the FERC's regulations. The FERC can also deny us the right to abandon certain facilities from service.

The FERC also regulates the rates we can charge for our natural gas transportation and storage operations. For our cost-based services, the FERC establishes both the maximum and minimum rates we can charge. The basic elements that the FERC considers are the costs of providing service, the volumes of gas being transported, the rate design, the allocation of costs between services, the capital structure and the rate of return a pipeline is permitted to earn. The FERC has issued a notice of inquiry concerning the inclusion of income taxes in the rates of an interstate pipeline that operates as a master limited partnership. The ultimate outcome of this proceeding could impact the maximum rates we can charge on our FERC-regulated pipelines. We may not be able to earn a return or recover all of our costs, including certain costs associated with pipeline integrity activities, through existing or future rates. The FERC or our customers can challenge the existing rates on any of our pipelines. Such a challenge against us could adversely affect our ability to charge rates that would cover future increases in our costs or even to continue to collect rates to maintain our current revenue levels that are designed to permit us a reasonable opportunity to recover current costs and depreciation and earn a reasonable return.

We may not continue making distributions to unitholders at the current distribution rate, or at all.

The amount of cash we have available to distribute to our unitholders depends upon the amount of cash we generate from our operations, financing activities, and the amount of cash we require, or determine to use, for other purposes, all of which fluctuate from quarter to quarter based on a number of factors, many of which are beyond our control. Some of the factors that influence the amount of cash we have available for distribution in any quarter include:

- fluctuations in cash generated by our operations, which may be affected by the seasonality of our business, timing of payments, defaults, general business conditions and market conditions that impact contract renewals, pricing, basis spreads, time period price spreads, market rates and supply and demand for natural gas and our services;

- the level of capital expenditures we make or anticipate making, including for expansion, growth projects and acquisitions;

- the amount of cash necessary to meet current or anticipated debt service requirements and other liabilities;

- fluctuations in our working capital needs;

- our ability to borrow funds and/or access capital markets on acceptable terms to fund operations or capital expenditures, including acquisitions, and restrictions contained in our debt agreements;

- the cost and form of payment for pending or anticipated acquisitions and growth or expansion projects and the timing and commercial success of any such initiatives; and

- unanticipated costs to operate our business, such as for maintenance and regulatory compliance.

There is no guarantee that unitholders will receive quarterly distributions from us. Our distributions are determined each quarter by the board of directors of our general partner based on the board’s consideration of our financial position, earnings, cash flow, current and future business needs and other relevant factors at the time when these decisions are made. We may reduce or eliminate distributions at any time our board determines that our cash reserves are insufficient or are otherwise required to fund current or anticipated future operations, capital expenditures, acquisitions, growth or expansion projects, debt repayment or other business needs.

A failure in our computer systems or a cybersecurity attack on any of our facilities, or those of third parties, may affect adversely our ability to operate our business.

We have become more reliant on technology to help increase efficiency in our business processes. Our businesses are dependent upon our operational and financial computer systems to process the data necessary to conduct almost all aspects of our business, including the operation of our pipeline and storage facilities and the recording and reporting of commercial and financial transactions. Any failure of our computer systems, or those of our customers, suppliers or others with whom we do business, could materially disrupt our ability to operate our business.

At the same time, the U.S. government has issued public warnings that indicate that energy assets might be specific targets of cybersecurity threats. Our technologies, systems and networks, and those of our vendors, suppliers and other business partners, may become the target of cyberattacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of operations. In addition, certain cyber-incidents may remain undetected for an extended period. As cyber-incidents continue to evolve, we will likely be required to expend additional resources to continue to modify or enhance our protective measures or to investigate and remediate any vulnerability to cyber-incidents. Our insurance coverage for cyberattacks may not be sufficient to cover all the losses we may experience as a result of such cyberattacks. Any cyberattacks that affect our facilities, or those of our customers, suppliers or others with whom we do business could have a material adverse effect on our business, cause us a financial loss and/or damage our reputation.

We may not be successful in executing our strategy to grow and diversify our business.

We rely primarily on the revenues generated from our natural gas long-haul transportation and storage services. Negative developments in these services have significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets. We are pursuing a strategy of growing and diversifying our business through acquisition and development of assets in complementary areas of the midstream energy sector, such as liquids transportation and storage assets. Our ability to grow, diversify and increase distributable cash flows will depend, in part, on our ability to expand our existing business lines and to close and execute on accretive acquisitions. We may not be successful in acquiring or developing such assets or may do so on terms that ultimately are not profitable. Any such transactions involve potential risks that may include, among other things:

- the diversion of management's and employees' attention from other business concerns;
- inaccurate assumptions about volume, revenues and project costs, including potential synergies;
- a decrease in our liquidity as a result of our using available cash or borrowing capacity to finance the acquisition or project;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance the acquisition or project;
- inaccurate assumptions about the overall costs of equity or debt;
- an inability to hire, train or retain qualified personnel to manage and operate the acquired business and assets or the developed assets;
- unforeseen difficulties operating in new product areas or new geographic areas; and
- changes in regulatory requirements or delays of regulatory approvals.

Additionally, acquisitions also contain the following risks:

- an inability to integrate successfully the businesses we acquire;
- the assumption of unknown liabilities for which we are not indemnified, for which our indemnity is inadequate or for which our insurance policies may exclude from coverage;
- limitations on rights to indemnity from the seller; and
- customer or key employee losses of an acquired business.

Our ability to replace expiring gas storage contracts at attractive rates or on a long-term basis and to sell short-term services at attractive rates or at all are subject to market conditions.

We own and operate substantial natural gas storage facilities. The market for the storage and PAL services that we offer is impacted by the factors and market conditions discussed above for our transportation services, and is also impacted by natural gas price differentials between time periods, such as winter to summer (time period price spreads), and the volatility in time period price spreads. When market conditions cause a narrowing of time period price spreads and a decline in the price volatility of natural gas, these factors adversely impact the rates we can charge for our storage and PAL services.

Failure to comply with environmental or worker safety laws and regulations or an accidental release of pollutants into the environment may cause us to incur significant costs and liabilities.

Our operations are subject to federal, regional, state and local laws and regulations relating to protection of worker safety or the environment. These laws include, for example, the CAA, the Clean Water Act, CERCLA, the Resource Conservation and Recovery Act, OSHA and analogous state laws. These laws and regulations may restrict or impact our business activities, including requiring the acquisition or renewal of permits or other approvals to conduct regulated activities, restricting the manner in which we handle or dispose of wastes, imposing remedial obligations to remove or mitigate contamination resulting from a spill or other release, requiring capital expenditures to comply with pollution control requirements and imposing safety and health criteria addressing worker protection. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, the occurrence of delays in the permitting or performance or expansion of projects and the issuance of orders enjoining future operations in a particular area. Under certain of these environmental laws and regulations, we could be subject to joint and several or strict liability for the removal or remediation of previously released pollutants or property contamination regardless of whether we were responsible for the release or contamination or if our operations were not in compliance with all laws. We may not be able to recover some or any of the costs incurred from insurance. Stricter environmental or worker safety laws, regulations or enforcement policies could significantly increase our operational or compliance costs and compliance with new or more stringent environmental legal requirements could delay or prohibit our ability to obtain permits for operations or require us to install additional pollution control equipment.

Our operations are subject to catastrophic losses, operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are a variety of operating risks inherent in transporting and storing natural gas, ethylene and NGLs, such as leaks and other forms of releases, explosions, fires, cyber-attacks and mechanical problems, some of which could have catastrophic consequences. Additionally, the nature and location of our business may make us susceptible to catastrophic losses from hurricanes or other named storms, particularly with regard to our assets in the Gulf Coast region, windstorms, earthquakes, hail, and severe winter weather. Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial financial losses. The location of pipelines in HCAs, which includes populated areas, residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from some of these risks.

We currently possess property, business interruption, cyber threat and general liability insurance, but proceeds from such insurance coverage may not be adequate for all liabilities or expenses incurred or revenues lost. Moreover, such insurance may not be available in the future at commercially reasonable costs and terms. The insurance coverage we do obtain may contain large deductibles or fail to cover certain events, hazards or all potential losses.

Our business requires the retention and recruitment of a skilled workforce and the loss of such workforce could result in the failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled executive team and workforce including engineers, technical personnel and other professionals. In addition, many of our current employees are approaching retirement age and have significant institutional knowledge that must be transferred to other employees. If we are unable to (a) retain our current employees, (b) successfully complete the knowledge transfer and/or (c) recruit new employees of comparable knowledge and experience, our business could be negatively impacted.

Our business is highly competitive.

The principal elements of competition among pipeline systems are availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability of service. Additionally, the FERC's policies promote competition in natural gas markets by increasing the number of natural gas transportation options available to our customer base. Increased competition could reduce the volumes of product we transport or store or, in instances where we do not have long-term contracts with fixed rates, could cause us to decrease the transportation or storage rates we can charge our customers. Competition could intensify the negative impact of factors that adversely affect the demand for our services, such as adverse economic conditions, weather, higher fuel costs and taxes or other regulatory actions that increase the cost, or limit the use, of products we transport and store.

Possible terrorist activities or military actions could adversely affect our business.

The continued threat of terrorism and the impact of retaliatory military and other action by the U.S. and its allies might lead to increased political, economic and financial market instability and volatility in prices for natural gas, which could affect the markets for our natural gas transportation and storage services. While we are taking steps that we believe are appropriate to increase the security of our assets, we may not be able to completely secure our assets or completely protect them against a terrorist attack.

Partnership Structure Risks

Our general partner and its affiliates own a controlling interest in us, have conflicts of interest and owe us only limited fiduciary duties, which may permit them to favor their own interests.

BPHC, a wholly-owned subsidiary of Loews, owns approximately 51% of our equity interests, excluding the IDRs, and owns and controls our general partner, which controls us. Although our general partner has a fiduciary duty to manage us in a manner beneficial to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner beneficial to BPHC. Furthermore, certain directors and officers of our general partner are also directors or officers of affiliates of our general partner. Conflicts of interest may arise between BPHC and its subsidiaries, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts, our general partner may favor its own interests and the interests of its affiliates over the interests of our unitholders. These potential conflicts include, among others, the following situations:

- BPHC and its affiliates may engage in competition with us;
- neither our partnership agreement nor any other agreement requires BPHC or its affiliates (other than our general partner) to pursue a business strategy that favors us. Directors and officers of BPHC and its affiliates have a fiduciary duty to make decisions in the best interest of BPHC shareholders, which may be contrary to our interests;
- our general partner is allowed to take into account the interests of parties other than us, such as BPHC and its affiliates, in resolving conflicts of interest, which has the effect of limiting its fiduciary duty to our unitholders;
- some officers of our general partner who provide services to us may devote time to affiliates of our general partner and may be compensated for services rendered to such affiliates;
- our partnership agreement limits the liability and reduces the fiduciary duties of our general partner and the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are consenting to some actions and conflicts of interest that might otherwise constitute a breach of fiduciary or other duties under applicable law;
- our general partner determines the amount and timing of asset purchases and sales, borrowings, repayments of indebtedness, issuances of additional partnership securities and cash reserves, each of which can affect the amount of cash that is available for distribution to our unitholders;
- our general partner determines the amount and timing of any capital expenditures and whether an expenditure is for maintenance capital, which reduces operating surplus, or a capital improvement expenditure, which does not. Such determination can affect the amount of cash that is distributed to our unitholders;
- in some instances, our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions;
- our general partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us;
- our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf, and provides that reimbursement to Loews for amounts allocable to us consistent with accounting and allocation methodologies generally permitted by the FERC for rate-making purposes and past business practices is deemed fair and reasonable to us;
- our general partner controls the enforcement of obligations owed to us by it and its affiliates;
- our general partner intends to limit its liability regarding our contractual obligations;
- our general partner decides whether to retain separate counsel, accountants or others to perform services for us; and
- our general partner may exercise its rights to call and purchase (1) all of our common units if, at any time, it and its affiliates own more than 80% of the outstanding common units or (2) all of our equity securities (including common units), if it and its affiliates own more than 50% in the aggregate of the outstanding common units and any other classes of equity securities and it receives an opinion of outside legal counsel to the effect that our being a pass-through entity for tax purposes has or is reasonably likely to have a material adverse effect on the maximum

applicable rates we can charge our customers.

Our partnership agreement limits our general partner's fiduciary duties to unitholders and restricts the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

Our partnership agreement contains provisions that reduce the standards to which our general partner would otherwise be held by state fiduciary duty law. For example, our partnership agreement:

- permits our general partner to make a number of decisions in its individual capacity, as opposed to its capacity as our general partner. This entitles our general partner to consider only the interests and factors that it desires, and it has no duty or obligation to give any consideration to any interest of, or factors affecting us, our affiliates or any limited partner. Decisions made by our general partner in its individual capacity will be made by a majority of the owners of our general partner, and not by the board of directors of our general partner. Examples of these kinds of decisions include the exercise of its call rights, its voting rights with respect to the units it owns and its registration rights and the determination of whether to consent to any merger or consolidation of the partnership;
- provides that our general partner shall not have any liability to us or our unitholders for decisions made in its capacity as general partner so long as it acted in good faith, meaning it believed that the decisions were in the best interests of the partnership;
- generally provides that affiliate transactions and resolutions of conflicts of interest not approved by the conflicts committee of the board of directors of our general partner and not involving a vote of unitholders must be on terms no less favorable to us than those generally provided to or available from unrelated third parties or be “fair and reasonable” to us and that, in determining whether a transaction or resolution is “fair and reasonable,” our general partner may consider the totality of the relationships between the parties involved, including other transactions that may be particularly advantageous or beneficial to us; and
- provides that our general partner and its officers and directors will not be liable for monetary damages to us, our limited partners or assignees for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that the general partner or those other persons acted in bad faith or engaged in fraud or willful misconduct.

We have a holding company structure in which our subsidiaries conduct our operations and own our operating assets, which may affect our ability to make distributions.

We are a partnership holding company and our operating subsidiaries conduct all of our operations and own all of our operating assets. We have no significant assets other than the ownership interests in our subsidiaries. As a result, our ability to make distributions to our unitholders depends on the performance of our subsidiaries and their ability to distribute funds to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of existing and future indebtedness, applicable state partnership and limited liability company laws and other laws and regulations, including FERC policies.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service (IRS) were to treat us as a corporation for federal income tax purposes, or if we were to become subject to material amounts of entity-level taxation for state tax purposes, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are organized as a limited partnership under Delaware law, we would be treated as a corporation for federal income tax purposes unless we satisfy a “qualifying income” requirement. Based upon our current operations, we believe we satisfy the qualifying income requirement. Failing to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate and would likely pay additional state income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution to our unitholders would be substantially reduced. Thus, treatment of us as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to a material amount of entity-level taxation for federal, state or local income tax purposes, the target distribution amounts will be adjusted to reflect the impact of that law on us. At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise, or other forms of taxation. Imposition of a similar tax on us in the jurisdictions in which we operate or in other jurisdictions to which we may expand could substantially reduce our cash available for distribution to our unitholders.

The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential administrative, legislative, or judicial changes or differing interpretations, possibly applied on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative, legislative, or judicial changes or differing interpretations at any time. From time to time, members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Although there is no current legislative proposal, a prior legislative proposal would have eliminated the qualifying income exception to the treatment of all publicly-traded partnerships as corporations upon which we rely for our treatment as a partnership for U.S. federal income tax purposes.

In addition, on January 24, 2017, final regulations regarding which activities give rise to qualifying income within the meaning of Section 7704 of the Code (the “Final Regulations”) were published in the Federal Register. The Final Regulations are effective as of January 19, 2017, and apply to taxable years beginning on or after January 19, 2017. We do not believe the Final Regulations affect our ability to continue to be treated as a partnership for U.S. federal income tax purposes.

Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. Any such changes could negatively impact the value of an investment in our common units.

If the IRS were to contest the federal income tax positions we take, the market for our common units may be adversely impacted and the costs of any IRS contest will reduce our cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the positions that we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take. A court may not agree with some or all of our counsel’s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. Moreover, the costs of any contest between us and the IRS will result in a reduction in our cash available for distribution to our unitholders.

If the IRS makes audit adjustments to our income tax returns for tax years beginning after December 31, 2017, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case our cash available for distribution to our unitholders might be substantially reduced.

Pursuant to the Bipartisan Budget Act of 2015, for tax years beginning after December 31, 2017, if the IRS makes audit adjustments to our income tax returns, it (and some states) may assess and collect any taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us. To the extent possible under the new rules, our general partner may choose to have us either pay the taxes (including any applicable penalties and interest) directly to the IRS or, if we are eligible, issue a revised Schedule K-1 to each unitholder with respect to an audited and adjusted return. Although our general partner may elect to have our unitholders take such audit adjustment into account in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. As a result, our current unitholders may bear some or all of the tax liability resulting from such audit adjustment, even if such unitholders did not own units in us during the tax year under audit. If, as a result of any such audit adjustment, we are required to make payments of taxes, penalties and interest, our cash available for distribution to our unitholders might be substantially reduced. These rules are not applicable for tax years beginning on or prior to December 31, 2017.

Our unitholders will be required to pay taxes on their share of our taxable income, including their share of income from the cancellation of debt, even if they do not receive any cash distributions from us.

Unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of our taxable income, whether or not they receive cash distributions from us. Unitholders may not receive cash distributions from us equal to such unitholders' share of our taxable income or even equal to the actual tax liability due from such unitholders' share of our taxable income.

We may engage in transactions to delever the partnership and manage our liquidity that may result in income to our unitholders without a corresponding cash distribution. For example, if we sell assets and use the proceeds to repay existing debt or fund capital expenditures, you may be allocated taxable income and gain resulting from the sale without receiving a cash distribution. Further, taking advantage of opportunities to reduce our existing debt, such as debt exchanges, debt repurchases, or modifications of our existing debt could result in "cancellation of indebtedness income" (also referred to as "COD income") being allocated to our unitholders as taxable income. Unitholders may be allocated COD income, and income tax liabilities arising therefrom may exceed cash distributions or the value of the units. The ultimate effect of any such allocations will depend on the unitholder's individual tax position with respect to its units. Unitholders are encouraged to consult their tax advisor with respect to the consequences to them of COD income.

Tax gain or loss on the disposition of our common units could be more or less than expected.

If our unitholders sell their common units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those common units. Because distributions in excess of a unitholder's allocable share of our net taxable income result in a decrease to such unitholder's tax basis in their common units, the amount, if any, of such prior excess distributions with respect to the units they sell will, in effect, become taxable income to the unitholder if they sell such units at a price greater than their tax basis in those units, even if the price they receive is less than their original cost. Furthermore, a substantial portion of the amount realized, whether or not representing a gain, may be taxed as ordinary income due to potential recapture of depreciation deductions and certain other items. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if our unitholders sell their units, they may incur a tax liability in excess of the amount of cash they receive from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investments in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (IRAs) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Distributions to non-U.S. persons will be subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. persons, and each non-U.S. person will be required to file federal tax returns and pay tax on their share of our taxable income. If you are a tax exempt entity or a non-U.S. person, you should consult your tax advisor before investing in our common units.

We will treat each purchaser of common units as having the same tax benefits without regard to the common units actually purchased. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we have adopted depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. It also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We generally prorate our items of income, gain, loss and deduction between transferors and transferees of our units each month based upon the ownership of our units on the first business day of each month (the "Allocation Date"), instead of on the basis of the date a particular unit is transferred. Similarly, we generally allocate certain deductions for depreciation of capital additions, gain or loss realized on a sale or other disposition of our assets and, in the discretion of the general partner, any other extraordinary item of income, gain, loss or deduction based upon ownership on the Allocation Date. Treasury Regulations allow a similar monthly simplifying convention, but may not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are the subject of a securities loan, (e.g., a loan to a "short seller" to cover a short sale of units) may be considered as having disposed of those units. If so, the unitholder would no longer be treated for tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because there are no specific rules governing the federal income tax consequences of loaning a partnership interest, a unitholder whose units are the subject of a securities loan may be considered as having disposed of the loaned units. In that case, the unitholder may no longer be treated for tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a securities loan are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies in determining unitholders' allocations of income, gain, loss and deduction. The IRS may challenge these methods or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we must routinely determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our common units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the timing or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of the common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered to have terminated as a partnership for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same interest will be counted only once. Our termination would, among other things, result in the closing of our taxable year for all unitholders, which would result in us filing two tax returns for one calendar year, and may result in a significant deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a calendar year, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in his taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes, but it would result in our being treated as a new partnership for tax purposes. If we were treated as a new partnership, we would be required to make new tax elections and could be subject to penalties if we were unable to determine that a termination occurred. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership may be permitted to provide only a single Schedule K-1 to unitholders for the two short tax periods included within the fiscal year in which the termination occurs.

Our unitholders may be subject to state and local taxes and return filing requirements as a result of investing in our common units.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or own property now or in the future, even if our unitholders do not reside in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, unitholders may be subject to penalties for failure to comply with those requirements. We conduct business in thirteen states. We may own property or conduct business in other states or foreign countries in the future. It is our unitholders' responsibility to file all federal, state and local tax returns.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We are headquartered in approximately 103,000 square feet of leased office space located in Houston, Texas. We also have approximately 60,000 square feet of leased office space in Owensboro, Kentucky. Our operating subsidiaries own their respective pipeline systems in fee. However, substantial portions of these systems are constructed and maintained on property owned by others pursuant to rights-of-way, easements, permits, licenses or consents. Our Pipeline and Storage Systems, in Item 1 of this Report contains additional information regarding our material property, including our pipelines and storage facilities.

Item 3. Legal Proceedings

Refer to Note 4 in Part II, Item 8 of this Report for a discussion of our legal proceedings.

Item 4. Mine Safety Disclosures

None.

PART II

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

Our Partnership Interests

As of December 31, 2016, we had outstanding 250.3 million common units, a 2% general partner interest and IDRs. The common units represent all of our limited partner interests and 98% of our total ownership interests, in each case excluding our IDRs. As discussed below under Our Cash Distribution Policy—Incentive Distribution Rights, the IDRs represent the right for the holder to receive varying percentages of quarterly distributions of available cash from operating surplus in excess of certain specified target quarterly distribution levels. As such, the IDRs cannot be expressed as a constant percentage of our total ownership interests.

BPHC, a wholly-owned subsidiary of Loews, owns 125.6 million of our common units and, through Boardwalk GP, an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of our IDRs. As of February 13, 2017, the common units and general partner interest owned by BPHC represent approximately 51% of our equity interests, excluding IDRs. The additional interest represented by the IDRs is not included in such ownership percentage because, as noted above, the IDRs cannot be expressed as a constant percentage of our ownership.

Market Information

As of February 13, 2017, we had 250.3 million common units outstanding held by approximately 41 holders of record. Our common units are traded on the NYSE under the symbol “BWP.”

The following table sets forth, for the periods indicated, the high and low sales prices for our common units, as reported on the NYSE Composite Transactions Tape, and information regarding our quarterly distributions. The closing sales price of our common units on the NYSE on February 13, 2017, was $18.49 per unit.

	Sales Price Range per Common Unit		Cash Distributions per Common Unit [1]
	High	Low	
Year Ended December 31, 2016:			
Fourth quarter	$18.49	$16.02	$0.1000
Third quarter	17.97	15.97	0.1000
Second quarter	18.16	13.96	0.1000
First quarter	14.83	8.86	0.1000
Year Ended December 31, 2015:			
Fourth quarter	$13.99	$10.54	$0.1000
Third quarter	15.08	11.26	0.1000
Second quarter	17.93	14.26	0.1000
First quarter	18.32	14.77	0.1000

(1) Represents cash distributions attributable to the quarter and declared and paid to limited partner unitholders within 60 days after quarter end.

Our Cash Distribution Policy

Our cash distribution policy is consistent with the terms of our partnership agreement which requires us to distribute our “available cash,” as that term is defined in our partnership agreement, on a quarterly basis. Our distributions are determined by the board of directors of our general partner based on our financial position, earnings, cash flow and other relevant factors. However, there is no guarantee that unitholders will receive quarterly distributions from us. Our distribution policy may be changed at any time and is subject to certain restrictions or limitations, including, among others, our general partner’s broad discretion to establish reserves which could reduce cash available for distributions, FERC regulations which place restrictions on various types of cash management programs employed by companies in the energy industry, including our operating subsidiaries subject to FERC jurisdiction, the requirements of applicable state partnership and limited liability company laws and the requirements of our revolving credit facility which would prohibit us from making distributions to unitholders if an event of default were to occur. In addition, we may lack sufficient cash to pay distributions to unitholders due to a number of factors, including those described in Risk Factors in Part I, Item 1A of this Report.

Incentive Distribution Rights

IDRs represent a limited partner ownership interest and include the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the target distribution levels have been achieved, as defined in our partnership agreement. Our general partner currently holds all of our IDRs, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement. Since 2014, no distributions have been paid on behalf of the IDRs. Note 12 in Part II, Item 8 of this Report contains more information regarding our distributions.

Assuming we do not issue any additional classes of units and our general partner maintains its 2% general partner interest, we will distribute any available cash from operating surplus for any quarter among the unitholders and our general partner as follows:

	Total Quarterly Distributions	Marginal Percentage Interest in Distributions	
	Target Amount	Limited Partner Unitholders	General Partner and IDRs
First Target Distribution	up to \$0.4025	98%	2%
Second Target Distribution	above \$0.4025 up to \$0.4375	85%	15%
Third Target Distribution	above \$0.4375 up to \$0.5250	75%	25%
Thereafter	above \$0.5250	50%	50%

Equity Compensation Plans

For information about our equity compensation plans, see Note 11 in Part II, Item 8 of this Report.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The following table presents our selected historical financial and operating data. As used herein, EBITDA means earnings before interest, income taxes, depreciation and amortization. EBITDA and distributable cash flow are not calculated or presented in accordance with accounting principles generally accepted in the U.S. of America (GAAP). We explain these measures below and reconcile them to the most directly comparable financial measures calculated and presented in accordance with GAAP in (2) Non-GAAP Financial Measures below. The financial data below should be read in conjunction with the Consolidated Financial Statements and Notes thereto included in Item 8 of this Report (in millions, except Net income per common unit (basic and diluted), Net income per class B unit (basic and diluted), Distributions per common unit and Distributions per class B unit):

	For the Year Ended December 31,				
	2016	2015	2014	2013	2012
Total operating revenues	$1,307.2	$1,249.2	$1,233.8	$1,205.6	$1,185.0
Net income attributable to controlling interest	302.2	222.0	233.6	253.7	306.0
Total assets	8,637.8	8,300.3	8,194.3	7,900.1	7,845.6
Long-term debt and capital lease obligation	3,558.0	3,459.3	3,677.2	3,410.0	3,522.3
Net income per common unit — basic	1.18	0.87	0.94	1.00	1.37
Net income per class B unit — basic (1)	—	—	—	0.05	0.36
Net income per common unit — diluted	—	—	—	0.96	1.37
Net income per class B unit — diluted (1)	—	—	—	0.48	0.36
Distributions per common unit	0.40	0.40	0.40	2.13	2.1275
Distributions per class B unit (1)	—	—	—	0.90	1.20
EBITDA (2)	803.0	722.2	687.6	688.7	726.5
Distributable cash flow (2)	507.3	413.3	449.4	558.6	497.4

(1) On October 9, 2013, the class B units converted to common units on a one-for-one basis pursuant to the terms of our partnership agreement.

(2) Non-GAAP Financial Measures.

We use non-GAAP measures to evaluate our business and performance, including EBITDA and distributable cash flow. EBITDA is used as a supplemental financial measure by management and by external users of our financial statements, such as investors, commercial banks, research analysts and rating agencies, to assess:

- our operating performance and return on invested capital as compared to those of other companies in the midstream portion of the natural gas and NGLs industry, without regard to financing methods and capital structure;
- our ability to generate cash sufficient to pay interest on our indebtedness and to make distributions to our partners; and
- the viability of acquisitions and capital expenditure projects.

Management and the external users of our financial statements, as described above, use distributable cash flow as an approximation of net operating revenues generated by us, that when realized in cash, will be available to be distributed to our unitholders and our general partner.

EBITDA and distributable cash flow should not be considered alternatives to, or more meaningful than, net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Certain items excluded from EBITDA and distributable cash flow are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as historic costs of depreciable assets. We have included information concerning EBITDA because EBITDA provides additional information as to our ability to meet our fixed charges and is presented solely as a supplemental measure. Likewise, we have included information concerning distributable cash flow as a supplemental financial measure we use to assess our ability to make distributions to our unitholders and general partner, because distributable cash flow approximates our net operating revenues that will be realized in cash. However, viewing EBITDA and distributable cash flow as indicators of our ability to make cash distributions on our common units should be done with caution, as we might be required to conserve funds or to allocate funds to business or legal purposes rather than making distributions. EBITDA and distributable cash flow are not necessarily comparable to similarly titled measures of another company.

The following table presents a reconciliation of EBITDA and distributable cash flow to net income, the most directly comparable GAAP financial measure for each of the periods presented below (in millions):

	For the Year Ended December 31,				
	2016	2015	2014	2013	2012
Net Income	$302.2	$222.0	$146.8	$250.2	$306.0
Net loss attributable to noncontrolling interests	—	—	(86.8)	(3.5)	—
Net income attributable to controlling interests	302.2	222.0	233.6	253.7	306.0
Income taxes	0.6	0.5	0.4	0.5	0.5
Depreciation and amortization	317.8	323.7	288.7	271.6	252.3
Interest expense	182.8	176.4	165.5	163.4	168.4
Interest income	(0.4)	(0.4)	(0.6)	(0.5)	(0.7)
EBITDA	$803.0	$722.2	$687.6	$688.7	$726.5
Less:					
Cash paid for interest net of capitalized interest (1)	170.6	170.6	153.0	151.0	169.8
Maintenance capital expenditures (2)	121.3	142.5	91.4	69.7	79.8
Base gas capital expenditures	—	—	14.7	—	—
Add:					
Proceeds from insurance recoveries and settlements (3)	—	6.2	6.3	—	9.2
Proceeds from sale of operating assets	0.2	0.8	2.9	60.7	5.9
Net gain on sale of operating assets	(0.1)	(0.5)	(1.1)	(29.5)	(3.3)
Asset impairment	3.8	0.4	3.0	4.1	9.1
Goodwill impairment	—	—	—	51.5	—
Bluegrass project impairment, net of noncontrolling interest	—	—	10.0	—	—
Other: (4)	(7.7)	(2.7)	(0.2)	3.8	(0.4)
Distributable Cash Flow	$507.3	$413.3	$449.4	$558.6	$497.4

(1) The year ended December 31, 2012, included $9.6 million of payments related to the settlements of interest rate derivatives.

(2) In 2014, the level of annual maintenance capital expenditures has risen due to an increase in integrity management activities, further discussed below under Pipeline System Maintenance. For the year ended December 31, 2015, maintenance capital expenditures were impacted by pipeline maintenance associated with our brine operations, pipeline integrity upgrades and continued increased integrity management activities.

(3) The amounts recorded for the years ended December 31, 2015 and 2014, represent amounts associated with legal settlements. The amount recorded for the year ended December 31, 2012, represents insurance recoveries associated with a fire at a compressor station and recoveries from legal settlements. All years exclude any proceeds recognized in earnings.

(4) Includes non-cash items such as the equity component of allowance for funds used during construction and equity in earnings, net of noncontrolling interests. The year ended December 31, 2013, includes the sale of ethylene inventory that was acquired through the acquisition of Louisiana Midstream.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A)

Overview

We are a master limited partnership operating in the midstream portion of the natural gas and NGLs industry, providing transportation and storage for those commodities. Our pipeline systems contain approximately 13,930 miles of interconnected natural gas pipelines, directly serving customers in thirteen states and indirectly serving customers throughout the northeastern and southeastern U.S. through numerous interconnections with unaffiliated pipelines. We also own approximately 435 miles of NGLs pipelines serving customers in Louisiana and Texas. In 2016, our pipeline systems transported approximately 2.3 Tcf of natural gas and approximately 64.8 MMBbls of NGLs. Average daily throughput on our natural gas pipeline systems during 2016 was approximately 6.3 Bcf. Our natural gas storage facilities are comprised of fourteen underground storage fields located in four states with aggregate working gas capacity of approximately 205.0 Bcf. Our NGLs storage facilities consist of nine salt-dome caverns located in Louisiana with a storage capacity of 24.0 MMBbls. We also have three salt-dome caverns being used to provide brine supply services and to support NGLs storage operations. We are not in the business of buying and selling natural gas and NGLs other than for system management purposes, but changes in natural gas and NGLs prices may impact the volumes of natural gas or NGLs transported and stored by customers on our systems. We conduct all of our business through our operating subsidiaries as one reportable segment.

Our transportation services consist of firm natural gas transportation, whereby the customer pays a capacity reservation charge to reserve pipeline capacity at receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume of natural gas actually transported, and interruptible natural gas transportation, under which the customer pays to transport gas only when capacity is available and used. The transportation rates we are able to charge customers are heavily influenced by market trends (both short and longer term), including the available natural gas supplies, geographical location of natural gas production, the demand for gas by end-users such as power plants, petrochemical facilities and LNG export facilities and the price differentials between the gas supplies and the market demand for the gas (basis differentials). Rates for short-term firm and interruptible transportation services are influenced by shorter-term market conditions such as current and forecasted weather.

We offer firm natural gas storage services in which the customer reserves and pays for a specific amount of storage capacity, including injection and withdrawal rights, and interruptible storage and PAL services where the customer receives and pays for capacity only when it is available and used. The value of our storage and PAL services (comprised of parking gas for customers and/or lending gas to customers) is affected by natural gas price differentials between time periods, such as between winter and summer (time period price spreads), price volatility of natural gas and other factors. Our storage and parking services have greater value when the natural gas futures market is in contango (a positive time period price spread, meaning that current price quotes for delivery of natural gas further in the future are higher than in the nearer term), while our lending service has greater value when the futures market is backwardated (a negative time period price spread, meaning that current price quotes for delivery of natural gas in the nearer term are higher than further in the future). The value of both storage and PAL services may also be favorably impacted by increased volatility in the price of natural gas, which allows us to optimize the value of our storage and PAL capacity.

We also transport and store NGLs. Contracts for our NGLs services are generally fee-based or based on minimum volume requirements, while others are dependent on actual volumes transported. Our NGLs storage rates are market-based and contracts are typically fixed-price arrangements with escalation clauses.

Due to the capital-intensive nature of our business, our operating costs and expenses typically do not vary significantly based upon the amount of products transported, with the exception of fuel consumed at our compressor stations and not included in a fuel tracker, which is included in Fuel and transportation expenses on our Consolidated Statements of Income.

Firm Transportation Agreements

A substantial portion of our transportation capacity is contracted for under firm transportation agreements. The table below sets forth the approximate projected revenues from capacity reservation and minimum bill charges under committed firm transportation agreements in place as of December 31, 2016, for 2017 and 2018, as well as the actual comparative amount recognized in revenues for 2016. The table does not include additional revenues we have recognized and may receive under firm transportation agreements based on actual utilization of the contracted pipeline capacity, any expected revenues for periods after the expiration dates of the existing agreements, execution of precedent agreements associated with growth projects or other events that occurred or will occur subsequent to December 31, 2016.

	As of December 31, 2016 (1) (in millions)
2016	$1,023.0
2017	1,055.0
2018	975.0

(1) For a discussion of risks associated with construction, the receipt of regulatory and other approvals and the nonperformance of our customers, refer to Part I, Item 1A. Risk Factors - Our actual construction and development costs could exceed our forecasts, our anticipated cash flow from construction and development projects will not be immediate and our construction and development projects may not be completed on time or at all and We are exposed to credit risk relating to default or bankruptcy by our customers.

The amounts shown for 2016 and 2017 increased approximately $13.0 million and $25.0 million from what was reported in our 2015 10-K. The increase in each year is primarily due to contract renewals and new contracts that were entered into during 2016.

Each year a portion of our firm transportation agreements expire and need to be renewed or replaced. In the 2018 to 2020 timeframe, the agreements associated with our East Texas Pipeline, Southeast Expansion, Gulf Crossing Pipeline and Fayetteville and Greenville Laterals, which were placed into service in 2008 and 2009, will expire. These projects were large, new pipeline expansions, developed to serve growing production in Texas, Oklahoma, Arkansas and Louisiana and anchored primarily by 10-year firm transportation agreements with producers. Since our expansion projects went into service, gas production from the Utica and Marcellus area in the Northeast, has grown significantly and has altered the flow patterns of natural gas in North America. Over the last few years, gas production from other basins such as Barnett and Fayetteville, which primarily supported two of our expansions, has declined because the production economics in those basins are not as competitive as other production basins, such as Utica and Marcellus. These market dynamics have resulted in less production from certain basins tied to our system and a narrowing of basis differentials across portions of our pipeline systems, primarily for capacity associated with natural gas flows from west to east. We expect that the total revenues generated from the expansion project's capacity could be materially lower when these contracts expire.

Our marketing efforts are focused on enhancing the value of this expansion capacity. We are working with customers to match gas supplies from various basins to new and existing customers and markets, including aggregating supplies at key locations along our pipelines to provide end-use customers with attractive and diverse supply options.

Partly as a result of the increase in overall gas supplies, demand markets, primarily in the Gulf Coast area, are growing due to new natural gas export facilities, power plants, petrochemical facilities and increased exports to Mexico. These developments have resulted in significant growth projects for us, as discussed under Growth Projects. We placed into service approximately $320.0 million of growth projects in 2016, and have an additional $1.3 billion of growth projects under development that are expected to be placed into service in 2017 and 2018. These new projects have lengthy planning and construction periods and, as a result, will not contribute to our earnings and cash flows until they are placed into service over the next several years. The revenues generated that will be realized in 2017 and 2018 from these projects are included in the table above. For a discussion of risks associated with our transportation revenues, please see Part I, Item 1A. Risk Factors - We may not be able to replace expiring natural gas transportation contracts at attractive rates or on a long-term basis and may not be able to sell short-term services at attractive rates or at all due to market conditions.

Pipeline System Maintenance

We incur substantial costs for ongoing maintenance of our pipeline systems and related facilities, including those incurred for pipeline integrity management activities, equipment overhauls, general upkeep and repairs. These costs are not dependent on the amount of revenues earned from our natural gas transportation services. PHMSA has developed regulations that require transportation pipeline operators to implement integrity management programs to comprehensively evaluate certain areas along pipelines and take additional measures to protect pipeline segments located in highly populated areas. These regulations have resulted in an overall increase in our ongoing maintenance costs, including maintenance capital and maintenance expense. PHMSA has proposed more prescriptive regulations, including expanded integrity management requirements, automatic or remote-controlled valve use, leak detection system installation, pipeline material strength testing and verification of maximum allowable pressures of certain pipelines, which if implemented, could require us to incur significant additional costs. See Part I, Item 1A. Risk Factors of this Report for further information.

Maintenance costs may be capitalized or expensed, depending on the nature of the activities. For any given reporting period, the mix of projects that we undertake will affect the amounts we record as property, plant and equipment (PPE) on our balance sheet or recognize as expenses, which impacts our earnings. In 2017, we expect to spend approximately $340.0 million to maintain our pipeline systems, of which approximately $140.0 million is expected to be maintenance capital. In 2016, we spent $321.2 million, of which $121.3 million was recorded as maintenance capital. The maintenance capital amounts include pipeline integrity upgrades associated with certain segments of our natural gas pipelines which are expected to be completed in 2018. Refer to Capital Expenditures for more information regarding certain of our maintenance costs and additional pipeline integrity upgrades.

Credit Risk

Credit risk relates to the risk of loss resulting from the default by a customer of its contractual obligations or the customer filing bankruptcy. We actively monitor our customer credit profiles, as well as the portion of our revenues generated from investment-grade and non-investment-grade customers. A majority of our customers are rated investment-grade by at least one of the major credit rating agencies; however, the ratings of several of our producer customers, including some of those supporting our growth projects, have been downgraded in the past year. The downgrades may restrict liquidity for those customers and indicate a greater likelihood of nonperformance of their contractual obligations, including failure to make future payments or, for customers supporting our growth projects, failure to post required letters of credit or other collateral as construction progresses. Refer to Part I, Item 1A. Risk Factors - We are exposed to credit risk relating to default or bankruptcy by our customers.

Results of Operations

The Overview section in this Item 7, and Note 2 of Item 8, contain summaries of our revenues and the related revenue recognition policies. A significant portion of our revenues are fee-based, being derived from capacity reservation charges under firm transportation agreements with customers, which do not vary significantly period to period, but are impacted by longer-term trends in our business such as lower pricing on contract renewals and other factors discussed elsewhere in this MD&A. Our operating costs and expenses do not vary significantly based upon the amount of products transported, with the exception of costs recorded in Fuel and transportation expense, which are typically offset by revenues from retained fuel included in our Transportation revenues.

Our Gulf South subsidiary filed a rate case with the FERC in 2014 and reached an uncontested settlement with its customers in 2015, which was subsequently approved by the FERC and became effective on March 1, 2016. The rate case settlement provided for, among other things, a system-wide rate design across the majority of the pipeline system, which resulted in a general overall increase in rates, and the April 1, 2016, implementation of a fuel tracker for determining future fuel rates. Since the implementation of the fuel tracker, fuel received from customers paying the full tariff rate and the related value of fuel used in transportation have been recorded as a net regulatory asset or liability on the balance sheet. Had the fuel tracker been implemented April 1, 2015, operating revenues would have been lower by $17.9 million and fuel and transportation expense would have been lower by $13.4 million for the year ended December 31, 2015. For the years ended December 31, 2016 and 2015, we recognized $18.2 million and $20.4 million of additional operating revenues as a result of the rate case.

Please refer to Firm Transportation Agreements and Pipeline System Maintenance above for further discussion of items that have impacted, or could impact in the future, our results of operations, including material trends in our operating revenues and expenses.

2016 Compared with 2015

Our net income attributable to controlling interests for the year ended December 31, 2016, increased $80.2 million, or 36%, to $302.2 million compared to $222.0 million for the year ended December 31, 2015, driven mainly by an increase in net operating revenues discussed below.

Operating revenues for the year ended December 31, 2016, increased $58.0 million, or 5%, to $1,307.2 million, compared to $1,249.2 million for the year ended December 31, 2015. Excluding the net effect of $12.7 million of proceeds received from the settlement of a legal matter in 2016 and $8.8 million of proceeds received from a business interruption claim in 2015, and items offset in fuel and transportation expense, primarily retained fuel, operating revenues increased $82.6 million, or 7%. The increase was driven by an increase in transportation revenues of $70.8 million, which resulted primarily from growth projects which were recently placed into service, incremental revenues from the Gulf South rate case and a full year of revenues from our Evangeline pipeline. Storage and PAL revenues were higher by $16.9 million primarily from the effects of favorable market conditions on time period price spreads.

Operating costs and expenses for the year ended December 31, 2016, decreased $23.7 million, or 3%, to $829.7 million, compared to $853.4 million for the year ended December 31, 2015. Excluding items offset in operating revenues, operating costs and expenses increased $4.8 million, or 1%, when compared to the comparable period in 2015. The operating expense increase was primarily due to higher employee-related costs, partially offset by decreases in maintenance activities and depreciation expense.

Total other deductions for the year ended December 31, 2016, increased $1.4 million, or 1%, to $174.7 million compared to $173.3 million for the 2015 period. The increase in total other deductions was due to an increase in interest expense. The proceeds from the May 2016 issuance of $550.0 million aggregate principal amount of 5.95% Boardwalk Pipelines notes due 2026 (Boardwalk Pipelines 2026 Notes) were initially used to reduce borrowings under our revolving credit facility, which has a lower weighted-average borrowing rate than the Boardwalk Pipelines 2026 Notes.

2015 Compared with 2014

Our net income attributable to controlling interests for the year ended December 31, 2015, decreased $11.6 million, or 5%, to $222.0 million compared to $233.6 million for the year ended December 31, 2014. In addition to the factors discussed below, net income for 2015 was favorably impacted by $7.6 million from the receipt of additional proceeds related to a business interruption claim for Louisiana Midstream. The 2014 period was impacted by a $10.0 million impairment charge, $7.1 million of which was reflected in operating expenses, related to the terminated Bluegrass project, a project between us, BPHC and The Williams Companies, Inc. (Bluegrass Project).

Operating revenues for the year ended December 31, 2015, increased $15.4 million, or 1%, to $1,249.2 million, compared to $1,233.8 million for the year ended December 31, 2014. Excluding the business interruption claim proceeds discussed above and items offset in fuel and transportation expense, primarily retained fuel and gas sales in 2014 associated with our Flag City processing plant, operating revenues increased $33.2 million, or 3%. The increase was driven by $39.5 million of higher transportation revenues primarily resulting from growth projects recently placed into service, including Evangeline which was acquired in October 2014, and $20.4 million of additional revenues resulting from the Gulf South rate case, partly offset by the comparably warm weather early in the year and the effects of the market conditions discussed above. Storage and PAL revenues were lower by $20.1 million primarily as a result of the effects of unfavorable market conditions on time period price spreads. Fuel retained, less fuel expense, was lower by $3.9 million primarily due to lower natural gas prices.

Operating costs and expenses for the year ended December 31, 2015, increased $17.7 million, or 2%, to $853.4 million, compared to $835.7 million for the year ended December 31, 2014. Excluding items offset in Operating revenues and the 2014 items discussed above, Operating costs and expenses increased $50.2 million, or 7%, when compared to the comparable period in 2014. The increase in operating expenses was driven by higher depreciation expense of $35.0 million from an increase in our asset base, including the Evangeline acquisition, and a change in the estimated lives of certain older, low-pressure assets, an increase in maintenance expenses of $14.7 million from pipeline system maintenance activities as discussed above and the Evangeline acquisition, as well as an increase in administrative and general expenses of $5.4 million primarily from employee-related costs.

Total other deductions for the year ended December 31, 2015, decreased $77.6 million, or 31%, to $173.3 million compared to $250.9 million for the 2014 period. The decrease was driven by prior year equity losses in unconsolidated affiliates of $86.5 million resulting from previously capitalized costs associated with the terminated Bluegrass Project that were expensed in 2014, most of which were offset by noncontrolling interests related to that project. The decrease in total other deductions was slightly offset by an increase in interest expense due to higher average debt balances as compared to the 2014 period, lower capitalized interest associated with capital projects and the expensing of previously deferred costs related to the refinancing of our revolving credit facility.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. Our principal sources of liquidity include cash generated from operating activities, our revolving credit facility, debt issuances, sales of limited partner units and our Subordinated Loan. Our operating subsidiaries use cash from their respective operations to fund their operating activities and maintenance capital requirements, service their indebtedness and make advances or distributions to Boardwalk Pipelines. Boardwalk Pipelines uses cash provided from the operating subsidiaries and, as needed, borrowings under our revolving credit facility to service outstanding indebtedness and make distributions or advances to us to fund our distributions to unitholders. We have no material guarantees of debt or other similar commitments to unaffiliated parties.

We anticipate that for 2017 our existing capital resources, including our revolving credit facility, Subordinated Loan and
our cash flows from operating activities, will be adequate to fund our operations. We may seek to access the capital markets to fund some or all capital expenditures for growth projects, acquisitions or for general partnership purposes. Our ability to access
the capital markets for equity and debt financing under reasonable terms depends on our financial condition, credit ratings and market conditions.

Equity and Debt Financing

At December 31, 2016, we had $4.6 million of cash on hand, and over $1.3 billion of available borrowing capacity under our revolving credit facility. In May 2016, we issued the Boardwalk Pipelines 2026 Notes, which proceeds were used to retire at their maturity our $250.0 million 5.875% notes that matured in November 2016 and our $300.0 million 5.50% notes that matured in February 2017. In the interim, we used the funds to reduce borrowings under our credit facility and fund capital projects. In January 2017, we received net proceeds of approximately $494.1 million after deducting underwriting discounts and offering expenses of $5.9 million from the sale of $500.0 million of 4.45% senior unsecured notes of Boardwalk Pipelines due July 15, 2027. We expect to use the proceeds from this offering to reduce borrowings under our revolving credit facility, fund growth capital expenditures and to repay future maturities of debt.

Credit Ratings

Most of our senior unsecured debt is rated by independent credit rating agencies. The credit ratings affect our ability to access the public and private debt markets, as well as the terms and the cost of our borrowings. Our ability to satisfy financing requirements or fund planned growth capital expenditures will depend upon our future operating performance and our ability to access the capital markets, which are affected by economic factors in our industry as well as other financial and business factors, some of which are beyond our control. As of February 13, 2017, our credit ratings for our senior unsecured notes and that of our operating subsidiaries having outstanding rated debt were as follows:

Rating agency	Rating (Us/Operating Subsidiaries)	Outlook (Us/Operating Subsidiaries)
Standard and Poor's[1]	BBB-/BBB-	Stable/Stable
Moody's Investor Services	Baa3/Baa2	Stable/Stable
Fitch Ratings, Inc.	BBB-/BBB-	Stable/Stable

(1) In August 2016, Standard and Poor’s raised our rating from BB+ to BBB-.

Credit ratings reflect the view of a rating agency and are not a recommendation to buy, sell or hold any security, and may be revised or withdrawn at any time by the rating agency if it determines that the facts and circumstances warrant such a change. Each credit agency’s rating should be evaluated independently of any other credit agency’s rating.

Revolving Credit Facility

As of December 31, 2016, we had $180.0 million of borrowings outstanding under our revolving credit facility with a weighted-average interest rate of 1.96% and no letters of credit issued thereunder. As of February 13, 2017, we had $65.0 million outstanding borrowings under our revolving credit facility, resulting in an available borrowing capacity of approximately $1.4 billion.

On July 29, 2016, we exercised a one-year extension option to extend the maturity date of our revolving credit facility to May 2021. One bank did not participate in the extension representing $25.0 million of commitments. The revolving credit facility contains various restrictive covenants and other usual and customary terms and conditions, including the incurrence of additional debt, the sale of assets and sale-leaseback transactions. The financial covenants under the revolving credit facility require us and our subsidiaries to maintain, among other things, a ratio of total consolidated debt to consolidated EBITDA (as defined in the amended credit agreement) measured for the previous twelve months of not more than 5.0 to 1.0, or up to 5.5 to 1.0, for the three quarters following an acquisition. We and our subsidiaries were in compliance with all covenant requirements under the revolving credit facility as of December 31, 2016. Note 10 in Part II, Item 8 of this Report contains more information regarding our revolving credit facility.

Subordinated Loan Agreement with Affiliate

In 2014, we entered into a Subordinated Loan Agreement with BPHC under which we can borrow up to $300.0 million until December 31, 2018. The Subordinated Loan bears interest at increasing rates, ranging from 5.75% to 9.75%, payable semi-annually in June and December, and matures in July 2024. The Subordinated Loan must be prepaid with the net cash proceeds from the issuance of additional equity securities by us or the incurrence of certain indebtedness by us or our subsidiaries, although BPHC may waive such prepayment. The Subordinated Loan is subordinated in right of payment to our obligations under our revolving credit facility pursuant to the terms of a Subordination Agreement between BPHC and Wells Fargo, N.A., as representative of the lenders under the revolving credit facility. Through the filing date of this Report, we have not borrowed any amounts under the Subordinated Loan.

Capital Expenditures

We capitalize construction costs and expenditures for major renewals and improvements which extend the lives of the respective assets. In accordance with our partnership agreement, we include as growth expenditures those expenditures associated with projects which are expected to increase an asset's operating capacity or our revenues or cash flows from that which existed immediately prior to the addition or improvement and which are expected to produce a financial return. Capital expenditures associated with projects that do not meet the preceding criteria are considered maintenance capital expenditures.

We are currently engaged in several growth projects, described in Part I, Item 1, Business - Current Growth Projects, of this Report. Several of our growth projects were placed into service in 2016, including the Ohio to Louisiana Access project, the Southern Indiana Lateral, the Western Kentucky Market Lateral and a power plant project in South Texas. These projects were completed on time and at an aggregate cost which was approximately $30.0 million lower than the $350.0 million originally estimated. A summary of the estimated total costs of our remaining growth projects and inception to date spending as of December 31, 2016, is as follows (in millions):

	Estimated Total Cost(1)	Cash Invested Through December 31, 2016
Northern Supply Access	$230.0	$ 148.5
Sulphur Storage and Pipeline Expansion	145.0	81.0
Coastal Bend Header	720.0	149.4
Other growth projects (2)	170.0	14.1
Total	$1,265.0	$ 393.0

(1) Estimates are based on internally developed financial models and time-lines. Factors in the estimates include, but are not limited to, those related to pipeline costs based on mileage, size and type of pipe, materials and construction and engineering costs.

(2) Other growth projects consist of projects in Louisiana comprised of three ethylene transportation and storage projects to serve industrial customers, the development of storage wells and associated facilities for brine supply services and a natural gas transportation project to serve a power plant. The power plant project remains subject to customer and FERC approvals.

Our cost and timing estimates for these projects are subject to a variety of risks and uncertainties, including obtaining regulatory approvals, adverse weather conditions, acquiring the right to construct and operate on other owners' land, delays in obtaining key materials and shortages of qualified labor. Refer to Part I, Item 1A. Risk Factors of this Report for additional risks associated with our growth projects and the related financing.

The nature of our existing growth projects will require us to enhance or modify our existing assets to accommodate increased operating pressures or changing flow patterns. We consider capital expenditures associated with the modification or enhancement of existing assets in the context of a growth project to be growth capital to the extent that the modification would not have been made in the absence of the growth project without regard to the condition of the existing assets.

Growth capital expenditures were $469.1 million, $232.0 million and $298.3 million for the years ended December 31, 2016, 2015 and 2014. Maintenance capital expenditures for the years ended December 31, 2016, 2015 and 2014 were $121.3

million, $142.5 million and $91.4 million. Our maintenance capital spending decreased in 2016 from the comparable period in 2015 due to decreased integrity management spending in 2016 and maintenance associated with certain brine facilities in 2015. In 2014, we purchased $14.7 million of natural gas to be used as base gas for our pipelines.

We expect total capital expenditures to be approximately $850.0 million in 2017, including approximately $140.0 million for maintenance capital and $710.0 million related to growth projects. Refer to Pipeline System Maintenance for further discussion of trends impacting our maintenance capital expenditures.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations under firm commitments as of December 31, 2016, by period (in millions):

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Principal payments on long-term debt (1)	$3,580.0	$575.0	$535.0	$620.0	$1,850.0
Interest on long-term debt (2)	949.6	167.0	268.3	213.3	301.0
Capital commitments (3)	218.2	218.2	—	—	—
Pipeline capacity agreements (4)	16.6	6.5	5.4	3.4	1.3
Operating lease commitments	27.3	4.7	7.6	6.7	8.3
Capital lease commitments (5)	12.7	1.0	2.1	2.2	7.4
Total	$4,804.4	$972.4	$818.4	$845.6	$2,168.0

(1) Includes our senior unsecured notes, having maturity dates from 2017 to 2027, and $180.0 million of loans outstanding under our revolving credit facility, having a maturity date of May 26, 2021. The amounts included in the Less than 1 Year column are included in long-term debt on our balance sheet. We have refinanced the notes maturing in less than a year on a long-term basis and otherwise have sufficient available borrowing capacity under our revolving credit facility to extend the amount that would come due in less than one year.

(2) Interest obligations represent interest due on our senior unsecured notes at fixed rates. Future interest obligations under our revolving credit facility are uncertain, due to the variable interest rate and fluctuating balances, and are not included in the table above. Based on a 1.96% weighted-average interest rate and an unused commitment fee of 0.18% as of December 31, 2016, our future cash obligations would be $5.9 million, $11.8 million and $8.3 million due in less than one year, 1-3 years and 3-5 years.

(3) Capital commitments represent binding commitments under purchase orders for materials ordered but not received and firm commitments under binding construction service agreements existing at December 31, 2016.

(4) The amounts shown are associated with pipeline capacity agreements on third-party pipelines that allow our operating subsidiaries to transport gas to off-system markets on behalf of our customers.

(5) Capital lease commitments represent future non-cancelable minimum lease payments under a capital lease agreement.

Pursuant to the settlement of the Texas Gas rate case in 2006, we are required to annually fund an amount to the Texas Gas pension plan equal to the amount of actuarially determined net periodic pension cost, including a minimum of $3.0 million. In 2017, we expect to fund approximately $3.0 million to the Texas Gas pension plan.

Distributions

For the years ended December 31, 2016, 2015 and 2014, we paid distributions of $102.2 million, $101.5 million and $99.2 million to our partners. Note 12 in Part II, Item 8 of this Report contains further discussion regarding our distributions.

Cash Flows from Operating, Investing and Financing Activities

A significant portion of our revenues are fee-based, being derived from capacity reservation charges under firm transportation agreements with customers, and our operating expenses do not vary significantly from period to period. Significant variability in cash flows from period to period generally results from changes in capital expenditures, pipeline maintenance costs and financing transactions, as well as other longer-term trends in our business which impact earnings, such as lower pricing on contract renewals and other factors, all of which are discussed elsewhere in this MD&A.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $24.4 million to $600.8 million for the year ended December 31, 2016, compared to $576.4 million for the comparable 2015 period primarily due to the change in net income, excluding the effects of non-cash items such as depreciation and amortization, partially offset by timing in accounts payable and the Gulf South rate refund.

Changes in cash flow from investing activities

Net cash used in investing activities increased $222.7 million to $590.2 million for the year ended December 31, 2016, compared to $367.5 million for the comparable 2015 period. The increase was primarily driven by an increase in capital expenditures of $215.9 million related to our growth projects discussed in Capital Expenditures.

Changes in cash flow from financing activities

Net cash used in financing activities decreased $203.3 million to $9.1 million for the year ended December 31, 2016, compared to $212.4 million for the comparable 2015 period. The decrease in cash used in financing activities resulted primarily from an increase in net proceeds of $319.8 million from the refinancing of maturing debt, partially offset by $115.4 million of proceeds received in the 2015 period from the sale of common units, including related general partner contributions.

Impact of Inflation

The cumulative impact of inflation over a number of years has resulted in increased costs for current replacement of productive facilities. The majority of our PPE is subject to rate-making treatment, and under current FERC practices, recovery is limited to historical costs. Amounts in excess of historical cost are not recoverable unless a rate case is filed. However, cost-based regulation, along with competition and other market factors, may limit our ability to price jurisdictional services to ensure recovery of inflation's effect on costs.

Off-Balance Sheet Arrangements

At December 31, 2016, we had no guarantees of off-balance sheet debt to third parties, no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings and no other off-balance sheet arrangements.

Critical Accounting Estimates and Policies

Our significant accounting policies are described in Note 2 in Part II, Item 8 of this Report. The preparation of these consolidated financial statements in accordance with GAAP requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses, and related disclosures of contingent assets and liabilities. Estimates are based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. The result of this process forms the basis for making judgments about the carrying amount of assets and liabilities that are not readily apparent from other sources. We review our estimates and judgments on a regular, ongoing basis. Changes in facts and circumstances may result in revised estimates and actual results may differ materially from those estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the periods in which the facts that give rise to the revisions become known.

The following accounting policies and estimates are considered critical due to the potentially material impact that the estimates, judgments and uncertainties affecting the application of these policies might have on our reported financial information.

Regulation

Most of our natural gas pipeline subsidiaries are regulated by the FERC. Pursuant to FERC regulations, certain revenues that we collect may be subject to possible refunds to our customers. Accordingly, during an open rate case, estimates of rate refund reserves are recorded based on regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. As previously discussed, Gulf South recently settled its rate case. As of December 31, 2015, a rate refund liability of $16.3 million associated with the rate case was recorded on our Consolidated Balance Sheets, which was settled through a combination of cash payments and invoice credits. As of December 31, 2016, there were no liabilities for any open rate case recorded on our Consolidated Balance Sheet.

When certain criteria are met, GAAP requires that certain rate-regulated entities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates (regulatory accounting). This basis of accounting is applicable to operations of our Texas Gas subsidiary which records certain costs and benefits as regulatory assets and liabilities in order to provide for recovery from or refund to customers in future periods, but is not applicable to operations associated with the Fayetteville and Greenville Laterals due to rates charged under negotiated rate agreements and a portion of the storage capacity due to the regulatory treatment associated with the rates charged for that capacity.

Effective April 1, 2016, Gulf South implemented a fuel tracker as a result of its settled rate case. We apply regulatory accounting for the fuel tracker, under which the value of fuel received from customers paying the full tariff rate and the related value of fuel used in transportation are recorded to a regulatory asset or liability depending on whether Gulf South uses more fuel than it collects from customers or collects more fuel than it uses. Prior to the implementation of the fuel tracker, the value of fuel received from customers was reflected in operating revenues and the value of fuel used was reflected in operating expenses. Other than as described for Texas Gas and Gulf South, regulatory accounting is not applicable to our other FERC-regulated operations.

We monitor the regulatory and competitive environment in which we operate to determine whether our regulatory assets continue to be probable of recovery. If we were to determine that all or a portion of our regulatory assets no longer met the criteria for recognition as regulatory assets, that portion which was not recoverable would be written off, net of any regulatory liabilities. Note 9 in Part II, Item 8 of this Report contains more information regarding our regulatory assets and liabilities.

Fair Value Measurements

Fair value refers to an exit price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal market in which the reporting entity transacts based on the assumptions market participants would use when pricing the asset or liability assuming its highest and best use. A fair value hierarchy has been established that prioritizes the information used to develop those assumptions giving priority, from highest to lowest, to quoted prices in active markets for identical assets and liabilities (Level 1); observable inputs not included in Level 1, for example, quoted prices for similar assets and liabilities (Level 2); and unobservable data (Level 3), for example, a reporting entity's own internal data based on the best information available in the circumstances. We use fair value measurements to account for our derivatives, asset retirement obligations, any impairment charges and the value of our plan assets associated with our pension and postretirement benefit plans. We also use fair value measurements to perform our goodwill impairment testing and report fair values for certain items in the Notes to the Consolidated Financial Statements in Part II, Item 8 of this Report. Notes 5 and 11 in Part II, Item 8 of this Report contain more information regarding our fair value measurements.

Environmental Liabilities

Our environmental liabilities are based on management's best estimate of the undiscounted future obligations for probable costs associated with environmental assessment and remediation of our operating sites. These estimates are based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these environmental matters. As of December 31, 2016 and 2015, we had an accrued liability of $5.0 million and $5.6 million for environmental matters. Our environmental accrued liabilities could change substantially in the future due to factors such as the nature and extent of any contamination, changes in remedial requirements, technological changes, discovery of new information and the involvement of and direction taken by the EPA, the FERC and other governmental authorities on these matters. We continue to conduct environmental assessments and are implementing a variety of remedial measures that may result in increases or decreases in the estimated environmental costs. Note 4 in Part II, Item 8 of this Report contains more information regarding our environmental liabilities.

Goodwill

Goodwill is tested for impairment at the reporting unit level at least annually or more frequently when events occur and circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. Accounting requirements provide that a reporting entity perform a quantitative analysis under a two-step impairment test to measure whether the fair value of the reporting unit is less than its carrying amount. If the fair value of the reporting unit is determined to be less than its carrying amount, including goodwill, the reporting entity must perform an analysis of the fair value of all of the assets and liabilities of the reporting unit. If the implied fair value of the reporting unit's goodwill is determined to be less than its carrying amount, an impairment loss is recognized for the difference. The implied fair value of goodwill is the excess of the fair value of the reporting unit over the fair value amounts assigned to all of the assets and liabilities of that unit as if the reporting unit was acquired in a business combination and the fair value of the reporting unit represented the purchase price.

We performed a quantitative goodwill impairment test for our reporting units as of November 30, 2016, which corresponds with the preparation of our five-year financial plan operating results. The fair value measurement of the reporting units was derived based on judgments and assumptions we believe market participants would use in assessing the fair value of the reporting units. These judgments and assumptions included the valuation premise, use of a discounted cash flow model to estimate fair value and inputs to the valuation model. The inputs included our five-year financial plan operating results, the long-term outlook for growth in natural gas demand in the U.S. and measures of the risk-free rate, equity premium and systematic risk used in the calculation of the applied discount rate under the capital asset pricing model. The use of alternate judgments and assumptions could substantially change the results of our goodwill impairment analysis, including the recognition of an impairment charge in our Consolidated Financial Statements.

The results of the quantitative goodwill impairment test for 2016 and 2015 indicated that the fair value of our reporting units significantly exceeded their carrying amounts and no goodwill impairment charges were recognized for the reporting units.

Impairment of Long-Lived Assets (including Tangible and Definite-Lived Intangible Assets)

We evaluate whether the carrying amounts of our long-lived and intangible assets have been impaired when circumstances indicate the carrying amount of those assets may not be recoverable. The carrying amount is not recoverable if it exceeds the undiscounted sum of cash flows expected to result from the use and eventual disposition of the asset. If the carrying amount is not recoverable, an impairment loss is measured as the excess of the asset's carrying amount over its fair value. We recognized \$3.8 million, \$0.4 million and \$10.1 million of asset impairment charges for the years ended December 31, 2016, 2015 and 2014.

Defined Benefit Plans

We are required to make a significant number of assumptions in order to estimate the net liabilities and costs related to our pension and postretirement benefit obligations to employees under our benefit plans. The assumptions that have the most impact on our pension and postretirement benefit costs are the discount rate, the expected return on plan assets and the rate of compensation increases. These assumptions are evaluated relative to current market factors in the U.S. such as inflation, interest rates and fiscal and monetary policies, as well as our policies regarding management of the plans such as the allocation of plan assets among investment options. Changes in these assumptions can have a material impact on obligations and related expense associated with these plans.

In determining the discount rate assumption, we utilize current market information and liability information provided by our plan actuaries, including a discounted cash flow analysis of our pension and postretirement obligations. In particular, the basis for our discount rate selection was the yield on indices of highly rated fixed income debt securities with durations comparable to that of our plan liabilities and with consideration of the change in interest rates, such as the U.S. Treasury yield curve. The Buck interest rate curve and the Citibank Pension Liability curve were consistently used as the basis for the change in discount rate from the last measurement date with this measure confirmed by the yield on other broad bond indices. Additionally, we supplement our discount rate decision with a yield curve analysis. The yield curve is applied to expected future retirement plan payments to adjust the discount rate to reflect the cash flow characteristics of the plans. The yield curve is a hypothetical AA/Aa yield curve represented by a series of annualized discount rates reflecting bond issues having a rating of Aa or better by Moody's Investors Service, Inc. Note 11 in Part II, Item 8 of this Report contains more information regarding our pension and postretirement benefit obligations.

Forward-Looking Statements

Investors are cautioned that certain statements contained in this Report, as well as some statements in periodic press releases and some oral statements made by our officials and our subsidiaries during presentations about us, are “forward-looking.” Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements, and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will likely result” and similar expressions. In addition, any statement made by our management concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects and possible actions by our partnership or our subsidiaries, are also forward-looking statements.

Forward-looking statements are based on current expectations and projections about future events and their potential impact on us. While management believes that these forward-looking statements are reasonable as and when made, there is no assurance that future events affecting us will be those that we anticipate. All forward-looking statements are inherently subject to a variety of risks and uncertainties, many of which are beyond our control, that could cause actual results to differ materially from those anticipated or projected. These risks and uncertainties include, among others:

- our ability to maintain or replace expiring gas transportation and storage contracts, to contract and physically make our systems bi-directional and to sell short-term capacity on our pipelines;

- our growth projects are supported by foundation shippers, many of which are major natural gas producers. The recent volatility in oil and natural gas prices could impact the foundation shippers ability to obtain credit support in the future and cause our counterparty credit risk to increase;

- the impact of changes to laws and regulations, such as the proposed GHG and methane legislation and other changes in environmental legislations, the pipeline safety bill, and regulatory changes that result from that legislation applicable to interstate pipelines, on our business, including our costs, liabilities and revenues;

- the costs of maintaining and ensuring the integrity and reliability of our pipeline systems, the need to remove pipeline and other assets from service as a result of such activities, and the timing and financial impacts of returning any such assets to service;

- we may not complete projects, including growth projects, that we have commenced or will commence, or we may complete projects on materially different terms, cost or timing than anticipated and we may not be able to achieve the intended economic or operational benefits of any such projects, if completed;

- the successful negotiation, consummation and completion of contemplated transactions, projects and agreements, including obtaining all necessary regulatory and customer approvals and resolving land owner opposition, or the timing, cost, scope, financial performance and execution of our recent, current and future acquisitions and growth projects;

- the impact to our business of our continuing to make distributions on our common units to our unitholders at our current distribution rate;

- the ability of our customers to pay for our services, including the ability of any foundation shippers on our growth projects to provide required credit support or otherwise comply with the terms of precedent agreements;

- the impact of new pipelines or new gas supply sources on competition and basis spreads on our pipeline systems;

- volatility or disruptions in the capital or financial markets;

- the impact of the FERC's rate-making policies and decisions on the services we offer, the rates we are proposing to charge or are charging and our ability to recover the full cost of operating our pipeline, including earning a reasonable return on equity;

- the success of our strategy to grow and diversify our business, including expansion into new product lines and geographic areas, especially in light of the volatile price levels of oil and natural gas experienced in 2016 which can influence the associated production of these commodities;

- the impact on our system throughput and revenues from changes in the supply of and demand for natural gas;

- our ability to access the bank and capital markets on acceptable terms to refinance our outstanding indebtedness and to fund our capital needs;

- operational hazards, litigation and unforeseen interruptions for which we may not have adequate or appropriate insurance coverage;

- the future cost of insuring our assets; and
- our ability to access new sources of natural gas and the impact on us of any future decreases in supplies of natural gas in our supply areas.

Developments in any of these areas could cause our results to differ materially from results that have been or may be anticipated or projected. Forward-looking statements speak only as of the date they are made and we expressly disclaim any obligation or undertaking to update these statements to reflect any change in our expectations or beliefs or any change in events, conditions or circumstances on which any forward-looking statement is based.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest rate risk:

With the exception of our revolving credit facility, for which the interest rates are periodically reset, our debt has been issued at fixed rates. For fixed-rate debt, changes in interest rates affect the fair value of the debt instruments but do not directly affect our earnings or cash flows. The following table presents market risk associated with our fixed-rate, long-term debt at December 31 (in millions, except interest rates):

	2016	2015
Carrying amount of fixed-rate debt	$3,378.9	$3,085.6
Fair value of fixed-rate debt	$3,529.2	$2,924.7
100 basis point increase in interest rates and resulting debt decrease	$148.3	$113.3
100 basis point decrease in interest rates and resulting debt increase	$160.2	$121.1
Weighted-average interest rate	5.46 %	5.32 %

At December 31, 2016, we had $180.0 million of variable-rate debt outstanding at a weighted-average interest rate of 1.96%. A 1% increase in interest rates would increase our cash payments for interest on our variable-rate debt by $1.8 million on an annualized basis. At December 31, 2015, we had $375.0 million outstanding under variable-rate agreements at a weighted-average interest rate of 1.67%.

At December 31, 2016 and 2015, $4.6 million and $3.1 million of our undistributed cash, shown on the Consolidated Balance Sheets as Cash and cash equivalents, was primarily invested in Treasury fund accounts. Due to the short-term nature of the Treasury fund accounts, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the fair market value of our Cash and cash equivalents.

Commodity risk:

Our pipelines do not take title to the natural gas and NGLs which they transport and store, therefore, they do not assume the related commodity price risk associated with the products. However, certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2016 and 2015, approximately $1.2 million and $10.5 million of gas stored underground, which we own and carry as current Gas and liquids stored underground, was available for sale and exposed to commodity price risk. We have historically managed our exposure to commodity price risk through the use of futures, swaps and option contracts; however, at December 31, 2016 and 2015, we had no outstanding derivatives.

Credit risk:

Our credit exposure generally relates to receivables for services provided, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and NNS. Natural gas price volatility can materially increase credit risk related to gas loaned to customers. We also have credit risk related to customers supporting our growth projects. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to pay for services provided by us, repay gas they owe to us, or post required credit support, this could have a material adverse effect on our business, financial condition, results of operations or cash flows.

As of December 31, 2016, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 13.6 trillion British thermal units (TBtu). Assuming an average market price during December 2016 of $3.47 per million British thermal units (MMBtu), the market value of that gas was approximately $47.2 million. As of December 31, 2016, the amount of NGLs owed to our operating subsidiaries due to imbalances was less than 0.1 MMBbls, which had a market value of approximately $0.4 million. As of December 31, 2015, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 7.7 TBtu. Assuming an average market price during December 2015 of $1.86 per MMBtu, the market value of this gas at December 31, 2015, would have been approximately $14.3 million. As of December 31, 2015, the amount of NGLs owed to our operating subsidiaries due to imbalances was less than 0.1 MMBbls, which had a market value of approximately $0.2 million.

Although nearly all of our customers pay for our services on a timely basis, we actively monitor the credit exposure to our customers. We include in our ongoing assessments, amounts due pursuant to services we render plus the value of any gas we have lent to a customer through no-notice or PAL services and the value of gas due to us under a transportation imbalance. Our natural gas pipeline tariffs contain language that allow us to require a customer that does not meet certain credit criteria to provide cash collateral, post a letter of credit or provide a guarantee from a credit-worthy entity in an amount equaling up to three months of capacity reservation charges. For certain agreements with customers, for example, those related to our growth projects, we have included contractual provisions that require additional credit support should the credit ratings of those customers fall below investment grade.

Natural gas producers comprise a significant portion of our revenues and support several of our growth projects. For example, in 2016, approximately 46% of our revenues were generated from contracts with natural gas producers. During the past couple of years, the prices of oil and natural gas declined as a result of increasing gas supplies, mainly from shale production areas in the U.S. During 2016, the prices of oil and natural gas remained volatile. Should the prices of natural gas and oil continue to remain volatile, we could be exposed to increased credit risk associated with our producer customer group. We continue to monitor our credit risk carefully, especially as it relates to customers that may be affected by the current oil and natural gas markets. Refer to Part I, Item 1A. Risk Factors - We are exposed to credit risk relating to default or bankruptcy by our customers for further discussion regarding credit risk.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Boardwalk GP, LLC
and the Partners of Boardwalk Pipeline Partners, LP

We have audited the accompanying consolidated balance sheets of Boardwalk Pipeline 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 changes in 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 Boardwalk Pipeline 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 15, 2017, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ Deloitte & Touche LLP
Houston, Texas
February 15, 2017

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(Millions)

	December 31,	
ASSETS	2016	2015
Current Assets:		
Cash and cash equivalents	$4.6	$3.1
Receivables:		
Trade, net	127.1	117.2
Other	12.7	12.3
Gas transportation receivables	8.2	5.6
Gas and liquids stored underground	1.3	10.7
Prepayments	17.7	16.9
Other current assets	2.6	4.0
Total current assets	174.2	169.8
Property, Plant and Equipment:		
Natural gas transmission and other plant	9,958.8	9,504.7
Construction work in progress	368.5	201.9
Property, plant and equipment, gross	10,327.3	9,706.6
Less—accumulated depreciation and amortization	2,333.8	2,052.2
Property, plant and equipment, net	7,993.5	7,654.4
Other Assets:		
Goodwill	237.4	237.4
Gas stored underground	93.5	97.6
Other	139.2	141.1
Total other assets	470.1	476.1
Total Assets	$8,637.8	$8,300.3

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED BALANCE SHEETS
(Millions)

	December 31,	
LIABILITIES AND PARTNERS' CAPITAL	2016	2015
Current Liabilities:		
Payables:		
Trade, net	$113.8	$99.1
Affiliates	1.4	1.3
Other	23.7	19.5
Gas payables	6.7	4.7
Accrued taxes, other	52.7	47.3
Accrued interest	40.6	39.7
Accrued payroll and employee benefits	38.5	33.2
Construction retainage	19.6	10.7
Deferred income	7.5	6.9
Customer rate refunds	—	16.3
Other current liabilities	28.4	35.7
Total current liabilities	332.9	314.4
Long–term debt and capital lease obligation	3,558.0	3,459.3
Other Liabilities and Deferred Credits:		
Pension liability	22.0	24.3
Asset retirement obligation	44.7	38.1
Provision for other asset retirement	63.7	57.2
Payable to affiliate	16.0	16.0
Other	69.6	64.3
Total other liabilities and deferred credits	216.0	199.9
Commitments and Contingencies		
Partners' Capital:		
Common units – 250.3 million units issued and outstanding as of December 31, 2016 and 2015	4,522.2	4,326.2
General partner	88.8	84.8
Accumulated other comprehensive loss	(80.1)	(84.3)
Total partners' capital	4,530.9	4,326.7
Total Liabilities and Partners' Capital	$8,637.8	$8,300.3

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME
(Millions, except per unit amounts)

	For the Year Ended December 31,		
	2016	2015	2014
Operating Revenues:			
Transportation	$1,142.4	$1,091.1	$1,065.1
Parking and lending	18.2	11.4	23.3
Storage	91.4	81.3	89.5
Other	55.2	65.4	55.9
Total operating revenues	1,307.2	1,249.2	1,233.8
Operating Costs and Expenses:			
Fuel and transportation	70.8	99.3	124.7
Operation and maintenance	199.9	209.5	194.8
Administrative and general	142.2	130.4	125.0
Depreciation and amortization	317.8	323.7	288.7
Asset impairment	3.8	0.4	10.1
Net gain on sale of operating assets	(0.1)	(0.5)	(1.1)
Taxes other than income taxes	95.3	90.6	93.5
Total operating costs and expenses	829.7	853.4	835.7
Operating income	477.5	395.8	398.1
Other Deductions (Income):			
Interest expense	182.8	176.4	165.5
Interest income	(0.4)	(0.4)	(0.6)
Equity losses in unconsolidated affiliates	—	—	86.5
Miscellaneous other income	(7.7)	(2.7)	(0.5)
Total other deductions	174.7	173.3	250.9
Income before income taxes	302.8	222.5	147.2
Income taxes	0.6	0.5	0.4
Net income	302.2	222.0	146.8
Net loss attributable to noncontrolling interests	—	—	(86.8)
Net income attributable to controlling interests	$302.2	$222.0	$233.6
Net Income per Unit:			
Net income per common unit	$1.18	$0.87	$0.94
Weighted-average number of common units outstanding	250.3	248.8	243.3
Cash distribution declared and paid to common units	$0.40	$0.40	$0.40

The accompanying notes are an integral part of these consolidated financial statements.

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BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions)

	For the Year Ended December 31,		
	2016	2015	2014
Net income	$302.2	$222.0	$146.8
Other comprehensive income (loss):			
Loss on cash flow hedges	—	—	(0.7)
Reclassification adjustment transferred to Net income from cash flow hedges	2.4	2.4	2.6
Pension and other postretirement benefit costs	1.8	(13.9)	(10.9)
Total Comprehensive Income	306.4	210.5	137.8
Comprehensive loss attributable to noncontrolling interests	—	—	(86.8)
Comprehensive income attributable to controlling interests	$306.4	$210.5	$224.6

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)

	For the Year Ended December 31,		
OPERATING ACTIVITIES:	2016	2015	2014
Net income	$302.2	$222.0	$146.8
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	317.8	323.7	288.7
Amortization of deferred costs and other	2.1	7.7	5.7
Asset impairment	3.8	0.4	10.1
Net gain on sale of operating assets	(0.1)	(0.5)	(1.1)
Equity losses in unconsolidated affiliates	—	—	86.5
Changes in operating assets and liabilities:			
Trade and other receivables	(10.4)	(18.6)	8.3
Other receivables, affiliates	—	—	1.0
Gas receivables and storage assets	10.9	(14.3)	(11.5)
Costs recoverable from customers	—	(0.3)	0.5
Other assets	0.8	(3.2)	5.8
Trade and other payables	(20.0)	39.4	(7.3)
Other payables, affiliates	(0.1)	(0.7)	0.2
Gas payables	5.3	(3.7)	(8.8)
Accrued liabilities	9.9	0.3	3.9
Other liabilities	(21.4)	24.2	(15.2)
Net cash provided by operating activities	600.8	576.4	513.6
INVESTING ACTIVITIES:			
Capital expenditures	(590.4)	(374.5)	(404.4)
Proceeds from sale of operating assets	0.2	0.8	2.9
Proceeds from insurance and other recoveries	—	6.2	6.3
Advances to affiliates	—	—	0.1
Investment in unconsolidated affiliates	—	—	(20.5)
Distributions from unconsolidated affiliates	—	—	11.1
Acquisition of businesses, net of cash acquired	—	—	(294.7)
Net cash used in investing activities	(590.2)	(367.5)	(699.2)
FINANCING ACTIVITIES:			
Proceeds from long-term debt, net of issuance cost	539.1	247.1	342.9
Repayment of borrowings from long-term debt and term loan	(250.0)	(725.0)	(25.0)
Proceeds from borrowings on revolving credit agreement	490.0	1,125.0	665.0
Repayment of borrowings on revolving credit agreement, including financing fees	(685.8)	(873.6)	(720.0)
Principal payment of capital lease obligation	(0.5)	(0.4)	(0.4)
Advances from affiliates	0.3	0.6	0.1
Distributions paid	(102.2)	(101.5)	(99.2)
Capital contributions from noncontrolling interests	—	—	8.2
Proceeds from sale of common units	—	113.1	—
Capital contributions from general partner	—	2.3	—
Distributions paid to noncontrolling interests	—	—	(7.9)
Net cash (used in) provided by financing activities	(9.1)	(212.4)	163.7
Increase (decrease) in cash and cash equivalents	1.5	(3.5)	(21.9)

Cash and cash equivalents at beginning of period	3.1	6.6	28.5
Cash and cash equivalents at end of period	$4.6	$3.1	$6.6

The accompanying notes are an integral part of these consolidated financial statements.

BOARDWALK PIPELINE PARTNERS, LP
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
(Millions)

	Partners' Capital				
	Common Units	General Partner	Accumulated Other Comp (Loss) Income	Non-controlling Interest	Total Equity
Balance January 1, 2014	$3,963.4	$77.3	$ (63.8)	$ 86.5	$4,063.4
Add (deduct):					
Net income (loss)	228.9	4.7	—	(86.8)	146.8
Distributions paid	(97.2)	(2.0)	—	—	(99.2)
Capital contributions from noncontrolling interests	—	—	—	8.2	8.2
Distributions paid to noncontrolling interests	—	—	—	(7.9)	(7.9)
Other comprehensive loss, net of tax	—	—	(9.0)	—	(9.0)
Balance December 31, 2014	$4,095.1	$80.0	$ (72.8)	$ —	$4,102.3
Add (deduct):					
Net income	217.5	4.5	—	—	222.0
Distributions paid	(99.5)	(2.0)	—	—	(101.5)
Sale of common units, net of related transaction costs	113.1	—	—	—	113.1
Capital contribution from general partner	—	2.3	—	—	2.3
Other comprehensive loss, net of tax	—	—	(11.5)	—	(11.5)
Balance December 31, 2015	$4,326.2	$84.8	$ (84.3)	$ —	$4,326.7
Add (deduct):					
Net income	296.2	6.0	—	—	302.2
Distributions paid	(100.2)	(2.0)	—	—	(102.2)
Other comprehensive income, net of tax	—	—	4.2	—	4.2
Balance December 31, 2016	$4,522.2	$88.8	$ (80.1)	$ —	$4,530.9

The accompanying notes are an integral part of these consolidated financial statements.

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BOARDWALK PIPELINE PARTNERS, LP

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1: Corporate Structure

Boardwalk Pipeline Partners, LP (the Partnership) is a Delaware limited partnership formed in 2005 to own and operate the business conducted by its primary subsidiary Boardwalk Pipelines, LP (Boardwalk Pipelines) and its operating subsidiaries, Gulf South Pipeline Company, LP (Gulf South), Texas Gas Transmission, LLC (Texas Gas), Gulf Crossing Pipeline Company LLC (Gulf Crossing), Boardwalk Louisiana Midstream, LLC (Louisiana Midstream), Boardwalk Petrochemical Pipeline, LLC (Boardwalk Petrochemical) and Boardwalk Field Services, LLC (together, the operating subsidiaries), which consists of integrated natural gas and natural gas liquids and other hydrocarbons (herein referred to together as NGLs) pipeline and storage systems. All of the Partnership's operations are conducted by the operating subsidiaries.

As of February 13, 2017, Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owned 125.6 million of the Partnership's common units, and, through Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of the incentive distribution rights (IDRs) of the Partnership. As of February 13, 2017, the common units and general partner interest owned by BPHC represent approximately 51% of the Partnership's equity interests, excluding the IDRs. The Partnership's common units are traded under the symbol "BWP" on the New York Stock Exchange (NYSE).

Note 2: Basis of Presentation and Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements of the Partnership were prepared in accordance with accounting principles generally accepted in the United States of America (U.S.) (GAAP).

Principles of Consolidation

The consolidated financial statements include the Partnership's accounts and those of its wholly-owned subsidiaries after elimination of intercompany transactions. The Partnership also consolidates variable interest entities (VIEs) in which the Partnership is the primary beneficiary. Third party or affiliate ownership interests in the Partnership's subsidiaries and consolidated VIEs are presented as noncontrolling interests.

The Bluegrass Project, described in Note 3, was a former project between the Partnership, BPHC and the Williams Companies, Inc. (Williams) (Bluegrass Project). The Partnership applied the equity method of accounting for this investment. Under the equity method, the carrying amounts of the Partnership's equity investments were increased by a proportionate share of the investee's net income and contributions made and decreased by a proportionate share of the investee's net losses and distributions received. As of December 31, 2016 and 2015, the Partnership had no equity method investments recorded on its Consolidated Balance Sheets.

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, liabilities, revenues, expenses and disclosure of contingent assets and liabilities and the fair values of certain items. The Partnership bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, which form the basis for making judgments about the carrying amounts of assets and liabilities that are not readily apparent from other sources. Actual results could differ from such estimates.

Segment Information

The Partnership operates in one reportable segment - the operation of interstate natural gas and NGLs pipeline systems and integrated storage facilities. This segment consists of interstate natural gas pipeline systems which are located in the Gulf Coast region, Oklahoma, Arkansas and the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio, and the Partnership's NGLs pipelines and storage facilities in Louisiana and Texas.

Regulatory Accounting

Most of the Partnership's natural gas pipeline subsidiaries are regulated by the Federal Energy Regulatory Commission (FERC). When certain criteria are met, GAAP requires that certain rate-regulated entities account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates (regulatory accounting). This basis of accounting is applicable to operations of the Partnership’s Texas Gas subsidiary, which records certain costs and benefits as regulatory assets and liabilities in order to provide for recovery from or refund to customers in future periods, but is not applicable to operations associated with the Fayetteville and Greenville Laterals due to rates charged under negotiated rate agreements and a portion of the storage capacity due to the regulatory treatment associated with the rates charged for that capacity.

The Partnership's Gulf South subsidiary filed a rate case with the FERC in 2014 and reached an uncontested settlement with its customers in 2015, which was subsequently approved by the FERC and became effective on March 1, 2016. The rate case settlement provided for, among other things, a system-wide rate design across the majority of the pipeline system which resulted in a general overall increase in rates and the implementation of a fuel tracker for determining future fuel rates. The fuel tracker went into effect April 1, 2016. The Partnership applies regulatory accounting for the fuel tracker, under which the value of fuel received from customers paying the full tariff rate and the related value of fuel used in transportation are recorded to a regulatory asset or liability depending on whether Gulf South uses more fuel than it collects from customers or collects more fuel than it uses. Prior to the implementation of the fuel tracker and the application of regulatory accounting, the value of fuel received from customers was reflected in operating revenues and the value of fuel used was reflected in operating expenses. As of December 31, 2015, the Partnership had a $16.3 million rate refund liability recorded on its Consolidated Balance Sheet, which was settled in April 2016 through a combination of cash payments and invoice credits. Other than as described for Texas Gas and Gulf South, regulatory accounting is not applicable to the Partnership’s other FERC-regulated operations.

The Partnership monitors the regulatory and competitive environment in which it operates to determine whether its regulatory assets continue to be probable of recovery. If the Partnership were to determine that all or a portion of its regulatory assets no longer met the criteria for recognition as regulatory assets, that portion which was not recoverable would be written off, net of any regulatory liabilities.

Note 9 contains more information regarding the Partnership’s regulatory assets and liabilities.

Fair Value Measurements

Fair value refers to an exit price that would be received to sell an asset or paid to transfer a liability in an orderly transaction in the principal market in which the reporting entity transacts based on the assumptions market participants would use when pricing the asset or liability assuming its highest and best use. A fair value hierarchy has been established that prioritizes the information used to develop those assumptions giving priority, from highest to lowest, to quoted prices in active markets for identical assets and liabilities (Level 1); observable inputs not included in Level 1, for example, quoted prices for similar assets and liabilities (Level 2); and unobservable data (Level 3), for example, a reporting entity’s own internal data based on the best information available in the circumstances. The Partnership uses fair value measurements to account for derivatives, asset retirement obligations (ARO) and any impairment charges. Fair value measurements are also used to perform goodwill impairment testing and report fair values for certain items contained in this Report. The Partnership considers any transfers between levels within the fair value hierarchy to have occurred at the beginning of a quarterly reporting period. The Partnership did not recognize any transfers between Level 1 and Level 2 of the fair value hierarchy and did not change its valuation techniques or inputs during the year ended December 31, 2016.

Notes 5 and 11 contain more information regarding fair value measurements.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with an original maturity of three months or less and are stated at cost plus accrued interest, which approximates fair value. The Partnership had no restricted cash at December 31, 2016 and 2015.

Cash Management

The operating subsidiaries participate in an intercompany cash management program with those that are FERC-regulated participating to the extent they are permitted under FERC regulations. Under the cash management program, depending on whether a participating subsidiary has short-term cash surpluses or cash requirements, Boardwalk Pipelines either provides cash to them or they provide cash to Boardwalk Pipelines. The transactions are represented by demand notes and are stated at historical carrying amounts. Interest income and expense are recognized on an accrual basis when collection is reasonably assured. The interest rate on intercompany demand notes is London Interbank Offered Rate (LIBOR) plus 1% and is adjusted every three months.

Trade and Other Receivables

Trade and other receivables are stated at their historical carrying amount, net of allowances for doubtful accounts. The Partnership establishes an allowance for doubtful accounts on a case-by-case basis when it believes the required payment of specific amounts owed is unlikely to occur. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or a receivable amount is deemed otherwise unrealizable.

Gas Stored Underground and Gas Receivables and Payables

Certain of the Partnership's operating subsidiaries have underground gas in storage which is utilized for system management and operational balancing, as well as for services including firm and interruptible storage associated with certain no-notice and parking and lending (PAL) services. Gas stored underground includes the historical cost of natural gas volumes owned by the operating subsidiaries, at times reduced by certain operational encroachments upon that gas. Current gas stored underground represents net retained fuel remaining after providing transportation and storage services which is available for resale and is valued at the lower of weighted-average cost or market.

The operating subsidiaries provide storage services whereby they store natural gas or NGLs on behalf of customers and also periodically hold customer gas under PAL services. Since the customers retain title to the gas held by the Partnership in providing these services, the Partnership does not record the related gas on its balance sheet. Certain of the Partnership's operating subsidiaries also periodically lend gas and NGLs to customers.

In the course of providing transportation and storage services to customers, the operating subsidiaries may receive different quantities of gas from shippers and operators than the quantities delivered on behalf of those shippers and operators. This results in transportation and exchange gas receivables and payables, commonly known as imbalances, which are primarily settled in cash or the receipt or delivery of gas in the future. Settlement of imbalances requires agreement between the pipelines and shippers or operators as to allocations of volumes to specific transportation contracts and timing of delivery of gas based on operational conditions. The receivables and payables are valued at market price for operations where regulatory accounting is not applicable and are valued at the historical value of gas in storage for operations where regulatory accounting is applicable.

Materials and Supplies

Materials and supplies are carried at average cost and are included in Other Assets on the Consolidated Balance Sheets. The Partnership expects its materials and supplies to be used for projects related to its property, plant and equipment (PPE) and for future growth projects. At December 31, 2016 and 2015, the Partnership held approximately $19.2 million and $22.2 million of materials and supplies.

Property, Plant and Equipment and Repair and Maintenance Costs

PPE is recorded at its original cost of construction or fair value of assets purchased. Construction costs and expenditures for major renewals and improvements which extend the lives of the respective assets are capitalized. Construction work in progress is included in the financial statements as a component of PPE. Repair and maintenance costs are expensed as incurred.

Depreciation of PPE related to operations for which regulatory accounting does not apply is provided for using the straight-line method of depreciation over the estimated useful lives of the assets, which range from 3 to 35 years. The ordinary sale or retirement of PPE for these assets could result in a gain or loss. Depreciation of PPE related to operations for which regulatory accounting is applicable is provided for primarily on the straight-line method at FERC-prescribed rates over estimated useful lives of 5 to 62 years. Reflecting the application of composite depreciation, gains and losses from the ordinary sale or retirement of PPE for these assets are not recognized in earnings and generally do not impact PPE, net.

Note 6 contains more information regarding the Partnership’s PPE.

Goodwill and Intangible Assets

Goodwill represents the excess of the cost of an acquisition over the fair value of the net identifiable assets acquired and liabilities assumed. Goodwill is tested for impairment at the reporting unit level at least annually, as of November 30, or more frequently when events occur and circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying amount. To test goodwill, a quantitative analysis is performed under a two-step impairment test to measure whether the fair value of the reporting unit is less than its carrying amount. If based upon a quantitative analysis the fair value of the reporting unit is less than its carrying amount, including goodwill, the Partnership performs an analysis of the fair value of all the assets and liabilities of the reporting unit. If the implied fair value of the reporting unit's goodwill is determined to be less than its carrying amount, an impairment loss is recognized for the difference.

Intangible assets are those assets which provide future economic benefit but have no physical substance. The Partnership recorded intangible assets for customer relationships obtained through its acquisitions. The customer relationships, which are included in Other Assets on the Consolidated Balance Sheets, have a finite life and are being amortized over their estimated useful lives.

Note 7 contains more information regarding the Partnership's goodwill and intangible assets.

Impairment of Long-lived Assets (including Tangible and Definite-lived Intangible Assets)

The Partnership evaluates its long-lived and intangible assets for impairment when, in management’s judgment, events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. When such a determination has been made, management’s estimate of undiscounted future cash flows attributable to the remaining economic useful life of the asset is compared to the carrying amount of the asset to determine whether an impairment has occurred. If an impairment of the carrying amount has occurred, the amount of impairment recognized in the financial statements is determined by estimating the fair value of the assets and recording a loss to the extent that the carrying amount exceeds the estimated fair value.

Capitalized Interest and Allowance for Funds Used During Construction (AFUDC)

The Partnership records capitalized interest, which represents the cost of borrowed funds used to finance construction activities for operations where regulatory accounting is not applicable. The Partnership records AFUDC, which represents the cost of funds, including equity funds, applicable to regulated natural gas transmission plant under construction as permitted by FERC regulatory practices, in connection with the Partnership’s operations where regulatory accounting is applicable. Capitalized interest and the allowance for borrowed funds used during construction are recognized as a reduction to Interest expense and the allowance for equity funds used during construction is included in Miscellaneous other income, net within the Consolidated Statements of Income. The following table summarizes capitalized interest and the allowance for borrowed funds and allowance for equity funds used during construction (in millions):

	For the Year Ended December 31,		
	2016	2015	2014
Capitalized interest and allowance for borrowed funds used during construction	$7.4	$3.4	$6.8
Allowance for equity funds used during construction	7.9	2.7	0.5

Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes related to the Partnership. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in Income taxes on the Consolidated Statements of Income.

Note 13 contains more information regarding the Partnership's income taxes.

Revenue Recognition

The maximum rates that may be charged by the majority of the Partnership's operating subsidiaries for their services are established through the FERC's cost-based rate-making process; however, rates actually charged by those operating subsidiaries may be less than those allowed by the FERC. Revenues from transportation and storage services are recognized in the period the service is provided based on contractual terms and the related volumes transported or stored. In connection with some PAL and interruptible storage service agreements, cash is received at the inception of the service period resulting in the recording of deferred revenues which are recognized in revenues over the period the services are provided. At December 31, 2016 and 2015, the Partnership had deferred revenues of $8.4 million and $10.0 million, which are expected to be recognized through 2018.

Retained fuel is recognized in revenues at market prices in the month of retention for operations where regulatory accounting is not applicable. The related fuel consumed in providing transportation services is recorded in Fuel and transportation expenses at market prices in the month consumed. In some cases, customers may elect to pay cash for the cost of fuel used in providing transportation services instead of having fuel retained in-kind. Retained fuel included in Transportation on the Consolidated Statements of Income for the years ended December 31, 2016, 2015 and 2014, was $29.1 million, $53.2 million and $90.3 million. As discussed under the Regulatory Accounting policy, Gulf South implemented a fuel tracker effective April 1, 2016, for customers paying the maximum tariff rate. Prior to the implementation of the fuel tracker and the application of regulatory accounting, the value of fuel received from customers was reflected in operating revenues and the value of fuel consumed was reflected in operating expenses.

The Partnership has contractual retainage provisions in some of its ethylene storage contracts that provide for the Partnership to retain ownership of 0.5% of customer inventory volumes injected into storage wells. The Partnership may sell the retainage volumes if commercially marketable volumes are on hand. The Partnership recognizes revenue for ethylene retainage volumes upon the physical sale of such volumes.

Under FERC regulations, certain revenues that the operating subsidiaries collect may be subject to possible refunds to customers. Accordingly, during a rate case, estimated refund liabilities are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2015, the Partnership had a $16.3 million refund liability related to the Gulf South rate case recorded on the Consolidated Balance Sheets, which was settled in April 2016 through a combination of cash payments and invoice credits. At December 31, 2016, the Partnership did not have a refund liability for any open rate case recorded on the Consolidated Balance Sheet.

Asset Retirement Obligations

The accounting requirements for existing legal obligations associated with the future retirement of long-lived assets require entities to record the fair value of a liability for an ARO in the period during which the liability is incurred. The liability is initially recognized at fair value and is increased with the passage of time as accretion expense is recorded, until the liability is ultimately settled. The accretion expense is included within Operation and maintenance costs within the Consolidated Statements of Income. An amount corresponding to the amount of the initial liability is capitalized as part of the carrying amount of the related long-lived asset and depreciated over the useful life of that asset.

Note 8 contains more information regarding the Partnership's ARO.

Environmental Liabilities

The Partnership records environmental liabilities based on management’s estimates of the undiscounted future obligation for probable costs associated with environmental assessment and remediation of operating sites. These estimates are based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these environmental matters.

Note 4 contains more information regarding the Partnership’s environmental liabilities.

Defined Benefit Plans

The Partnership maintains postretirement benefit plans for certain employees. The Partnership funds these plans through periodic contributions which are invested until the benefits are paid out to the participants, and records an asset or liability based on the overfunded or underfunded status of the plan. The net benefit costs of the plans are recorded in the Consolidated Statements of Income. Any deferred amounts related to unrecognized gains and losses or changes in actuarial assumptions are recorded as either a regulatory asset or liability or recorded as a component of accumulated other comprehensive income (AOCI) until those gains or losses are recognized in the Consolidated Statements of Income.

Note 11 contains more information regarding the Partnership’s pension and postretirement benefit obligations.

Unit-Based and Other Long-Term Compensation

The Partnership provides awards of phantom common units (Phantom Common Units) to certain employees under its Long-Term Incentive Plan (LTIP). The Partnership also provides to certain employees awards of long-term cash bonuses (Long-Term Cash Bonuses) under the Boardwalk Pipeline Partners Unit Appreciation Rights (UAR) and Cash Bonus Plan.

The Partnership measures the cost of an award issued in exchange for employee services based on the grant-date fair value of the award, or the stated amount in the case of the Long-Term Cash Bonuses and amounts under retention payment agreements. All outstanding awards are required to be settled in cash and are classified as a liability until settlement. Unit-based compensation awards are remeasured each reporting period until the final amount of awards is determined. The related compensation expense, less an estimate of forfeitures, is recognized over the period that employees are required to provide services in exchange for the awards, usually the vesting period.

Note 11 contains more information regarding the Partnership’s unit-based and other long-term compensation.

Partner Capital Accounts

For purposes of maintaining capital accounts, items of income and loss of the Partnership are allocated among the partners each period, or portion thereof, in accordance with the partnership agreement, based on their respective ownership interests, after deducting any priority allocations in the form of cash distributions paid to the general partner as the holder of IDRs.

Recently Issued Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update 2014-09, Revenue from Contracts with Customers (Topic 606), (ASU 2014-09) which will require entities to recognize revenue in an amount that reflects the transfer of promised goods or services to a customer in an amount based on the consideration the entity expects to be entitled to in exchange for those goods or services. ASU 2014-09 also requires disclosures regarding the nature, amount, timing and uncertainty of revenues and cash flows from contracts with customers. The amendments may be applied retrospectively to each prior period presented, or retrospectively with the cumulative effect recognized as of the date of initial application. ASU 2014-09 is effective for interim and annual reporting periods beginning after December 15, 2017. The Partnership has substantially completed a review of its contracts with customers in relation to the requirements of ASU 2014-09, and has tentatively concluded that the implementation of ASU 2014-09 will have no impact on its revenue recognition policies for a substantial number of its contracts. However, certain items remain outstanding that could impact those conclusions. The Partnership is working with an industry group to develop positions regarding those outstanding items. The Partnership intends to apply ASU 2014-09 to its financial statements retrospectively with the cumulative effect of implementation recognized as of January 1, 2018.

In February 2016, the FASB issued Accounting Standards Update 2016-02, Leases (Topic 842) (ASU 2016-02), which will require, among other things, the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under current GAAP. The amendments are to be applied at the beginning of the earliest period presented using a modified retrospective approach. ASU 2016-02 is effective for interim and annual reporting periods beginning after December 15, 2018, however, early adoption is permitted. The Partnership has initiated a project to evaluate the impact that ASU 2016-02 will have on its financial statements when implemented, however, no conclusions have been reached.

Note 3: Investments and Acquisitions

Bluegrass Project

In 2013, the Partnership and Williams formed joint ventures for the development of the Bluegrass Project. In 2014, due to cost escalations, construction delays and lack of customer commitments, among other things, the assets related to the joint ventures were determined to be impaired and were measured at fair value on a non-recurring basis. As a result, in the first quarter 2014, the Bluegrass Project entities, which were dissolved in December 2014, expensed the previously capitalized project costs, resulting in a $92.9 million charge, which was reflected in Equity losses in unconsolidated affiliates and Asset impairment on the income statement. Net of noncontrolling interests of $82.9 million, these expenses reduced the Partnership's Net income attributable to controlling interests by $10.0 million.

Acquisition of Boardwalk Petrochemical

On October 8, 2014, the Partnership completed the acquisition of Boardwalk Petrochemical, which owns and operates the Evangeline ethylene pipeline system, from Chevron Pipe Line Company, for $294.7 million in cash.

Note 4: Commitments and Contingencies

Legal Proceedings and Settlements

The Partnership's subsidiaries are parties to various legal actions arising in the normal course of business. Management believes the disposition of these outstanding legal actions will not have a material impact on the Partnership's financial condition, results of operations or cash flows.

Southeast Louisiana Flood Protection Litigation

The Partnership and its subsidiary, Gulf South, along with approximately 100 other energy companies operating in Southern Louisiana, have been named as defendants in a petition for damages and injunctive relief in state district court for Orleans Parish, Louisiana, (Case No. 13-6911) by the Board of Commissioners of the Southeast Louisiana Flood Protection Authority - East (Flood Protection Authority). The case was filed in state court, but was removed to the U.S. District Court for the Eastern District of New Orleans (Court) in August 2013. The lawsuit claims include negligence, strict liability, public nuisance, private nuisance, breach of contract and breach of the natural servitude of drain against the defendants, alleging that the defendants' drilling, dredging, pipeline and industrial operations since the 1930s have caused increased storm surge risk, increased flood protection costs and unspecified damages to the Flood Protection Authority. In addition to attorney fees and unspecified monetary damages, the lawsuit seeks abatement and restoration of the coastal lands, including backfilling and revegetating of canals dredged and used by the defendants, and abatement and restoration activities such as wetlands creation, reef creation, land bridge construction, hydrologic restoration, shoreline protection, structural protection, bank stabilization and ridge restoration. On February 13, 2015, the Court dismissed the case with prejudice. The Flood Protection Authority has appealed the dismissal of the case to the U.S. Court of Appeals for the Fifth Circuit in May 2015 (Case No. 15-CV-30162). On February 29, 2016, the Flood Protection Authority argued against the Court's dismissal of the case in a hearing held before the Fifth Circuit. The Partnership is awaiting the Fifth Circuit's issuance of a ruling on the appeal.

In February 2015, Gulf South, along with other energy companies, was named a defendant in a petition for damages and injunctive relief filed by Joseph Bernstein (Case No. 744-226; 24th Judicial District Court for the Parish of Jefferson) and the Defelice Land Company, L.L.C. (Case No. 61-926; 25th Judicial District Court for the Parish of

Plaquemines). These cases are similar in nature to the Flood Protection Authority case discussed above. Both cases were originally filed in the Louisiana state court and were removed to federal court. In the second quarter 2015, the cases were remanded to Louisiana state court.

Settlements and Insurance Proceeds

For the year ended December 31, 2016, the Partnership received $12.7 million in cash from the settlement of a legal claim which was recorded in Transportation revenues.

For the years ended December 31, 2015 and 2014, the Partnership received $8.8 million and $1.2 million in insurance proceeds from a business interruption claim related to Louisiana Midstream, which were recorded in Transportation revenues.

Environmental and Safety Matters

The operating subsidiaries are subject to federal, state and local environmental laws and regulations in connection with the operation and remediation of various operating sites. As of December 31, 2016 and 2015, the Partnership had an accrued liability of approximately $5.0 million and $5.6 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, groundwater protection measures and other costs. The liability represents management's estimate of the undiscounted future obligations based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these matters. The related expenditures are expected to occur over the next five years. As of December 31, 2016 and 2015, approximately $1.7 million was recorded in Other current liabilities and approximately $3.3 million and $3.9 million were recorded in Other Liabilities and Deferred Credits.

Clean Air Act and Climate Change

The Partnership's pipelines are subject to the Clean Air Act, as amended, (CAA) and comparable state laws and regulations, which restrict the emission of air pollutants from many sources and impose various monitoring and reporting requirements. Under the CAA, the Partnership may be required to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. The need to obtain permits has the potential to delay the development or expansion of the Partnership's projects. Over the next several years, the Partnership may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in 2015, the Environmental Protection Agency (EPA) issued a final rule under the CAA, lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. The EPA is expected to make final geographical attainment designations and issue final non-attainment area requirements pursuant to this NAAQS rule by late 2017 and states are also expected to implement more stringent regulations that could apply to the Partnership's operations. Compliance with this final rule could, among other things, require installation or new emission controls on some of the Partnership's equipment, result in longer permitting timelines and significantly increase its capital expenditures and operating costs. Additionally, the EPA has determined that greenhouse gas (GHG) emissions endanger public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has adopted regulations under the CAA related to GHG emissions.

Lease Commitments

The Partnership has various operating lease commitments extending through the year 2028 generally covering office space and equipment rentals. Total lease expense for the years ended December 31, 2016, 2015 and 2014, was approximately $13.2 million, $12.2 million and $10.7 million. The following table summarizes minimum future commitments related to these items at December 31, 2016 (in millions):

2017	$4.7
2018	4.1
2019	3.5
2020	3.4
2021	3.3
Thereafter	8.3
Total	$27.3

Commitments for Construction

The Partnership’s future capital commitments are comprised of binding commitments under purchase orders for materials ordered but not received and firm commitments under binding construction service agreements. The commitments as of December 31, 2016, were approximately $218.2 million, all of which are expected to be settled within the next twelve months.

Pipeline Capacity Agreements

The Partnership's operating subsidiaries have entered into pipeline capacity agreements with third-party pipelines that allow the operating subsidiaries to transport gas to off-system markets on behalf of customers. The Partnership incurred expenses of $6.5 million, $6.9 million and $10.1 million related to pipeline capacity agreements for the years ended December 31, 2016, 2015 and 2014. The future commitments related to pipeline capacity agreements as of December 31, 2016, were (in millions):

2017	$6.5
2018	3.7
2019	1.7
2020	1.7
2021	1.7
Thereafter	1.3
Total	$16.6

Note 5: Other Comprehensive Income and Fair Value Measurements

Other Comprehensive Income

The Partnership estimates that approximately $4.1 million of net losses reported in AOCI as of December 31, 2016, are expected to be reclassified into earnings within the next twelve months. This amount is comprised of a $1.7 million decrease to earnings related to net periodic benefit cost and a $2.4 million decrease to earnings related to cash flow hedges. The amount related to cash flow hedges are from treasury rate locks used in hedging interest payments associated with debt offerings that were settled in previous periods and are being amortized to earnings over the terms of the related interest payments, generally the terms of the related debt. The following table shows the components and reclassifications to net income of Accumulated other comprehensive loss which is included in Partners' Capital on the Consolidated Balance Sheets for the years ended December 31, 2014 through 2016 (in millions):

	Cash Flow Hedges	Pension and Other Postretirement Costs	Total
Beginning balance, January 1, 2014	$(12.7)	$ (51.1)	$(63.8)
Loss recorded in accumulated other comprehensive loss	(0.7)	—	(0.7)
Reclassifications:			
Other operating revenues	0.2	—	0.2
Interest expense [1]	2.4	—	2.4
Pension and other postretirement benefit costs	—	(10.9)	(10.9)
Ending balance, December 31, 2014	$(10.8)	$ (62.0)	$(72.8)
Reclassifications: Interest expense [1]	2.4	—	2.4
Pension and other postretirement benefit costs	—	(13.9)	(13.9)
Ending balance, December 31, 2015	$(8.4)	$ (75.9)	$(84.3)
Reclassifications: Interest expense [1]	2.4	—	2.4
Pension and other postretirement benefit costs	—	1.8	1.8
Ending balance, December 31, 2016	$(6.0)	$ (74.1)	$(80.1)

(1) Related to amounts deferred in AOCI from the treasury rate locks described above.

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Financial Assets and Liabilities

As of December 31, 2016 and 2015, the Partnership had no assets and liabilities which were recorded at fair value on a recurring basis. The following methods and assumptions were used in estimating the fair value amounts included in the disclosures for financial assets and liabilities:

Cash and Cash Equivalents: For cash and short-term financial assets, the carrying amount is a reasonable estimate of fair value due to the short maturity of those instruments.

Long-Term Debt: The estimated fair value of the Partnership's publicly traded debt is based on quoted market prices at December 31, 2016 and 2015. The fair market value of the debt that is not publicly traded is based on market prices of similar debt at December 31, 2016 and 2015. The carrying amount of the Partnership's variable-rate debt approximates fair value because the instruments bear a floating market-based interest rate.

The carrying amount and estimated fair values of the Partnership's financial assets and liabilities which were not recorded at fair value on the Consolidated Balance Sheets as of December 31, 2016 and 2015, were as follows (in millions):

As of December 31, 2016		Estimated Fair Value			
Financial Assets	Carrying Amount	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$4.6	$4.6	$—	$ —	$4.6
Financial Liabilities					
Long-term debt	$3,558.9 (1)	$—	$3,709.2	$ —	$3,709.2

(1) The carrying amount of long-term debt excludes an $8.6 million long-term capital lease obligation and $9.5 million of unamortized debt issuance costs.

As of December 31, 2015		Estimated Fair Value			
Financial Assets	Carrying Amount	Level 1	Level 2	Level 3	Total
Cash and cash equivalents	$3.1	$3.1	$—	$ —	$3.1
Financial Liabilities					
Long-term debt	$3,460.6 (1)	$—	$3,299.7	$ —	$3,299.7

(1) The carrying amount of long-term debt excludes a $9.1 million long-term capital lease obligation and $10.4 million of unamortized debt issuance costs.

Note 6: Property, Plant and Equipment

The following table presents the Partnership's PPE as of December 31, 2016 and 2015 (in millions):

Category	2016 Amount	Weighted-Average Useful Lives (Years)	2015 Amount	Weighted-Average Useful Lives (Years)
Depreciable plant:				
Transmission	$8,337.1	38	$7,930.3	37
Storage	779.2	38	769.5	38
Gathering	385.2	28	347.6	27
General	194.2	13	182.8	13
Rights of way and other	125.7	36	122.5	37
Total utility depreciable plant	9,821.4	37	9,352.7	37
Non-depreciable:				
Construction work in progress	368.5		201.9	
Storage	105.5		105.5	
Land	31.9		30.2	
Other	—		16.3	
Total non-depreciable assets	505.9		353.9	
Total PPE	10,327.3		9,706.6	
Less: accumulated depreciation	2,333.8		2,052.2	
Total PPE, net	$7,993.5		$7,654.4	

The non-depreciable assets were not included in the calculation of the weighted-average useful lives.

The Partnership holds undivided interests in certain assets, including the Bistineau storage facility of which the Partnership owns 92%, the Mobile Bay Pipeline of which the Partnership owns 64% and offshore and other assets, comprised of pipeline and gathering assets in which the Partnership holds various ownership interests. In addition, the Partnership owns 83% of two ethylene wells and supporting surface facilities in Choctaw, Louisiana, and certain ethylene and propylene pipelines connecting Louisiana Midstream's storage facilities in Choctaw to chemical manufacturing plants in Geismar, Louisiana.

The proportionate share of investment associated with these interests has been recorded as PPE on the balance sheets. The Partnership records its portion of direct operating expenses associated with the assets in Operation and maintenance expense. The following table presents the gross PPE investment and related accumulated depreciation for the Partnership's undivided interests as of December 31, 2016 and 2015 (in millions):

	2016 Gross PPE Investment	Accumulated Depreciation	2015 Gross PPE Investment	Accumulated Depreciation
Bistineau storage	$73.6	$ 21.8	$68.9	$ 19.5
Mobile Bay Pipeline	13.3	5.4	13.2	5.1
NGL pipelines and facilities	34.8	4.2	34.8	3.2
Offshore and other assets	15.1	11.8	17.1	12.8
Total	$136.8	$ 43.2	$134.0	$ 40.6

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Asset Impairment Charges

The Partnership recognized \$3.8 million, \$0.4 million and \$10.1 million of asset impairment charges for the years ended December 31, 2016, 2015 and 2014. The asset impairment charges recorded in 2016 were primarily due to materials and supplies inventory that were determined to be obsolete, and the charges in 2015 were primarily due to an increase in the estimate of ARO related to retired assets. The asset impairment charges recorded in 2014 primarily related to the Bluegrass Project.

Note 7: Goodwill and Intangible Assets

Goodwill

As of December 31, 2016 and 2015, the Partnership had recorded in its Consolidated Balance Sheets \$237.4 million of goodwill. The Partnership performed its annual goodwill impairment test for its reporting units as of November 30, 2016. The results of the quantitative goodwill impairment test indicated that the fair value of the Partnership's reporting units significantly exceeded their carrying amounts. No impairment charge related to goodwill was recorded for any of the Partnership's reporting units during 2016, 2015 or 2014.

Intangible Assets

The following table contains information regarding the Partnership's intangible assets, which includes customer relationships acquired as part of its acquisitions (in millions):

	December 31,	
	2016	2015
Gross carrying amount	\$59.4	\$59.4
Accumulated amortization	(7.5)	(5.5)
Net carrying amount	\$51.9	\$53.9

For the years ended December 31, 2016, 2015 and 2014, amortization expense for intangible assets was \$2.0 million, \$2.0 million and \$1.4 million and was recorded in Depreciation and amortization on the Consolidated Statements of Income. Amortization expense for the next five years and in total thereafter as of December 31, 2016, is expected to be as follows (in millions):

2017	\$2.0
2018	2.0
2019	2.0
2020	1.9
2021	1.9
Thereafter	42.1
	\$51.9

The weighted-average remaining useful life of the Partnership's intangible assets as of December 31, 2016, was 27 years.

Note 8: Asset Retirement Obligations

The Partnership has identified and recorded legal obligations associated with the abandonment of certain pipeline and storage assets, brine ponds, offshore facilities and the abatement of asbestos consisting of removal, transportation and disposal when removed from certain compressor stations and meter station buildings. Legal obligations exist for the main pipeline and certain other Partnership assets; however, the fair value of the obligations cannot be determined because the lives of the assets are indefinite, therefore cash flows associated with retirement of the assets cannot be estimated with the degree of accuracy necessary to establish a liability for the obligations.

The following table summarizes the aggregate carrying amount of the Partnership's ARO as of December 31, 2016 and 2015 (in millions):

	2016	2015
Balance at beginning of year	$52.6	$46.3
Liabilities recorded	3.3	9.7
Liabilities settled	(5.7)	(5.1)
Accretion expense	1.7	1.7
Balance at end of year	51.9	52.6
Less: Current portion of ARO	(7.2)	(14.5)
Long-term ARO	$44.7	$38.1

For the Partnership's operations where regulatory accounting is applicable, depreciation rates for PPE are comprised of two components. One component is based on economic service life (capital recovery) and the other is based on estimated costs of removal (as a component of negative salvage) which is collected in rates and does not represent an existing legal obligation. The Partnership has reflected $63.7 million and $57.2 million as of December 31, 2016 and 2015, in the accompanying Consolidated Balance Sheets as Provision for other asset retirement related to the estimated cost of removal collected in rates.

Note 9: Regulatory Assets and Liabilities

The amounts recorded as regulatory assets and liabilities in the Consolidated Balance Sheets as of December 31, 2016 and 2015, are summarized in the table below. The table also includes amounts related to unamortized debt expense and unamortized discount on long-term debt, while not regulatory assets and liabilities, are a critical component of the embedded cost of debt financing utilized in Texas Gas' rate proceedings. The tax effect of the equity component of AFUDC represents amounts recoverable from rate payers for the tax recorded in regulatory accounting. Certain amounts in the table are reflected as a negative, or a reduction, to be consistent with the regulatory books of account. The period of recovery for the regulatory assets included in rates varies from one to eighteen years. The remaining period of recovery for regulatory assets not yet included in rates would be determined in future rate proceedings. None of the regulatory assets shown below were earning a return as of December 31, 2016 and 2015 (in millions):

	2016	2015
Regulatory Assets:		
Pension	$10.6	$10.6
Tax effect of AFUDC equity	2.7	3.1
Total regulatory assets	$13.3	$13.7

Regulatory Liabilities:		
Cashout and fuel tracker	$10.1	$6.0
Provision for other asset retirement	63.7	57.2
Unamortized debt expense and premium on reacquired debt	(6.8)	(8.0)
Unamortized discount on long-term debt	(1.0)	(1.2)
Postretirement benefits other than pension	45.9	39.9
Total regulatory liabilities	$111.9	$93.9

Note 10: Financing

Long-Term Debt

The following table presents all long-term debt issues outstanding as of December 31, 2016 and 2015 (in millions):

	2016	2015
Notes and Debentures:		
Boardwalk Pipelines		
5.875% Notes due 2016 (Boardwalk Pipelines 2016 Notes)	$—	$250.0
5.50% Notes due 2017 (Boardwalk Pipelines 2017 Notes)	300.0	300.0
5.20% Notes due 2018	185.0	185.0
5.75% Notes due 2019	350.0	350.0
3.375% Notes due 2023	300.0	300.0
4.95% Notes due 2024	600.0	600.0
5.95% Notes due 2026	550.0	—
Gulf South		
6.30% Notes due 2017 (Gulf South 2017 Notes)	275.0	275.0
4.00% Notes due 2022	300.0	300.0
Texas Gas		
4.50% Notes due 2021	440.0	440.0
7.25% Debentures due 2027	100.0	100.0
Total notes and debentures	3,400.0	3,100.0
Revolving Credit Facility:		
Gulf Crossing	180.0	375.0
Capital lease obligation	8.6	9.1
	3,588.6	3,484.1
Less:		
Unamortized debt discount	(21.1)	(14.4)
Unamortized debt issuance costs	(9.5)	(10.4)
Total Long-Term Debt and Capital Lease Obligation	$3,558.0	$3,459.3

Maturities of the Partnership’s long-term debt for the next five years and in total thereafter are as follows (in millions):

2017	$575.0
2018	185.0
2019	350.0
2020	—
2021	620.0
Thereafter	1,850.0
Total long-term debt	$3,580.0

The Partnership has included $575.0 million of debt which matures in less than one year as long-term debt on its Consolidated Balance Sheet as of December 31, 2016. The Partnership refinanced the Boardwalk Pipelines 2017 Notes on a long-term basis with available capacity under the revolving credit facility. The Partnership refinanced the

Gulf South 2017 Notes on a

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long-term basis with the issuance of its $500.0 million aggregate principal amount of Boardwalk Pipelines 4.45% notes due 2027 discussed below.

Notes and Debentures

As of December 31, 2016 and 2015, the weighted-average interest rate of the Partnership's notes and debentures was 5.46% and 5.32%. For the years ended December 31, 2016, 2015 and 2014, the Partnership completed the following debt issuances (in millions, except interest rates):

Date of Issuance	Issuing Subsidiary	Amount of Issuance	Purchaser Discounts and Expenses	Net Proceeds		Interest Rate	Maturity Date	Interest Payable
May 2016	Boardwalk Pipelines	$ 550.0	$ 10.9	$ 539.1	(1)	5.95 %	June 1, 2026	June 1 and December 1
March 2015	Boardwalk Pipelines	$ 250.0	$ 2.9	$ 247.1	(2)	4.95 %	December 15, 2024	June 15 and December 15
November 2014	Boardwalk Pipelines	$ 350.0	$ 7.1	$ 342.9	(3)	4.95 %	December 15, 2024	June 15 and December 15

(1) The net proceeds of this offering were used to retire the Boardwalk Pipelines 2016 Notes and the Boardwalk Pipelines 2017 Notes. Initially, the Partnership used the net proceeds to reduce outstanding borrowings under its revolving credit facility. Subsequently, on November 15, 2016, and February 1, 2017, the Partnership retired all of the outstanding aggregate principal amount of Boardwalk Pipelines 2016 Notes and Boardwalk Pipelines 2017 Notes with borrowings under its revolving credit facility.

(2) The net proceeds of this offering were used to retire a portion of the outstanding $250.0 million aggregate principal amount of the Texas Gas 4.60% notes due 2015 (Texas Gas 2015 Notes). Initially, the Partnership used the net proceeds to reduce outstanding borrowings under its revolving credit facility. Subsequently, on June 1, 2015, the Partnership retired the Texas Gas 2015 Notes with borrowings under its revolving credit facility.

(3) The net proceeds of this offering were used to retire all of the outstanding $275.0 million aggregate principal amount of the Gulf South 5.05% notes due 2015 and the remainder of the net proceeds were used to reduce outstanding borrowings under the Partnership's revolving credit facility.

In January 2017, the Partnership received net proceeds of approximately $494.1 million from the issuance of $500.0 million aggregate principal amount of Boardwalk Pipelines 4.45% notes due in July 2027. The proceeds from this offering will be used to refinance future maturities of debt and to fund growth capital expenditures. Initially, the proceeds will be used to reduce outstanding borrowings under the revolving credit facility.

The Partnership’s notes and debentures are redeemable, in whole or in part, at the Partnership’s option at any time, at a redemption price equal to the greater of 100% of the principal amount of the notes to be redeemed or a “make whole” redemption price based on the remaining scheduled payments of principal and interest discounted to the date of redemption at a rate equal to the Treasury rate plus 20 to 50 basis points depending upon the particular issue of notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default.

The indentures governing the notes and debentures have restrictive covenants which provide that, with certain exceptions, neither the Partnership nor any of its subsidiaries may create, assume or suffer to exist any lien upon any property to secure any indebtedness unless the debentures and notes shall be equally and ratably secured. All of the Partnership's debt obligations are unsecured. At December 31, 2016, Boardwalk Pipelines and its operating subsidiaries were in compliance with their debt covenants.

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Revolving Credit Facility

The Partnership has a revolving credit facility having aggregate lending commitments of $1.5 billion and includes Boardwalk Pipelines, Texas Gas, Gulf South and Gulf Crossing as borrowers (Borrowers). Interest is determined, at the Partnership's election, by reference to (a) the base rate which is the highest of (1) the prime rate, (2) the federal funds rate plus 0.50% and (3) the one month Eurodollar Rate plus 1.00%, plus an applicable margin, or (b) the LIBOR plus an applicable margin. The applicable margin ranges from 0.00% to 0.75% for loans bearing interest based on the base rate and ranges from 1.00% to 1.75% for loans bearing interest based on the LIBOR rate, in each case determined based on the individual Borrower's credit rating from time to time. The Third Amended and Restated Revolving Credit Agreement (amended credit agreement) provides for a quarterly commitment fee charged on the average daily unused amount of the revolving credit facility ranging from 0.10% to 0.275% which is determined based on the individual Borrower's credit rating from time to time. In 2016, the Partnership extended the maturity date of the revolving credit facility by one year to May 26, 2021. One bank did not participate in the extension representing $25.0 million of commitments.

The revolving credit facility contains various restrictive covenants and other usual and customary terms and conditions, including restrictions regarding the incurrence of additional debt, the sale of assets and sale-leaseback transactions. The financial covenants under the revolving credit facility require the Partnership and its subsidiaries to maintain, among other things, a ratio of total consolidated debt to consolidated EBITDA (as defined in the amended credit agreement) measured for the previous twelve months of not more than 5.0 to 1.0, or up to 5.5 to 1.0 for the three quarters following an acquisition. The Partnership and its subsidiaries were in compliance with all covenant requirements under the revolving credit facility as of December 31, 2016.

Outstanding borrowings under the Partnership's revolving credit facility as of December 31, 2016 and 2015, were $180.0 million and $375.0 million with a weighted-average borrowing rate of 1.96% and 1.67%. As of February 13, 2017, the Partnership had $65.0 million outstanding borrowings and approximately $1.4 billion of available borrowing capacity under the revolving credit facility.

Subordinated Loan Agreement with Affiliate

The Partnership has in place a Subordinated Loan Agreement with BPHC (Subordinated Loan) under which the Partnership can borrow up to $300.0 million through December 31, 2018. The Subordinated Loan bears interest at increasing rates, ranging from 5.75% to 9.75%, payable semi-annually in June and December, and matures in July 2024. The Subordinated Loan must be prepaid with the net cash proceeds from the issuance of additional equity securities by the Partnership or the incurrence of certain indebtedness by the Partnership or its subsidiaries, although BPHC may waive such prepayment. The Subordinated Loan is subordinated in right of payment to the Partnership’s obligations under its revolving credit facility pursuant to the terms of a Subordination Agreement between BPHC and Wells Fargo, N.A., as representative of the lenders under the revolving credit facility. Through the filing date of this Report, the Partnership has not borrowed any amounts under the Subordinated Loan.

Capital Lease

The Partnership recorded a capital lease obligation of $10.5 million in 2013 related to the lease of an office building in Owensboro, Kentucky. The office building lease has a term of fifteen years with two twenty-year renewal options. Future commitments under the capital lease are $1.0 million for years 2017 and 2018, $1.1 million for years 2019 through 2021 and $7.4 million thereafter. After deducting $3.6 million for amounts representing interest, the present value of the capital lease obligation at December 31, 2016, was $9.1 million, of which $0.5 million was recorded in Other Current Liabilities and $8.6 million was recorded in Long-term debt and capital lease obligation.

Amortization of the office building under the capital lease for each of the years ended December 31, 2016, 2015 and 2014, was $0.7 million and was included in Depreciation and amortization. As of December 31, 2016 and 2015, assets recorded in Natural gas transmission and other plant under the capital lease were $10.5 million and the accumulated amortization was $2.4 million and $1.7 million.

Issuances of Common Units

The Partnership had no common unit issuances for the years ended December 31, 2016 and 2014. For the year ended December 31, 2015, the Partnership completed the following issuances and sales of common units under an equity distribution agreement (in millions, except the issuance price):

Month of Offering	Number of Common Units	Issuance Price	Less Underwriting Discounts and Expenses	Net Proceeds (including General Partner Contribution)	Common Units Outstanding After Offering	Common Units Held by the Public After Offering
February 2015 - April 2015	7.0	$16.19 (1)	$ 1.1	$ 115.4	250.3	124.6

(1) The issuance price represents the average issuance price for the common units issued under an equity distribution agreement.

Summary of Changes in Outstanding Units

The following table summarizes changes in the Partnership's common units since January 1, 2014 (in millions):

	Common Units
Balance, January 1, 2014 and December 31, 2014	243.3
Common units issued under an equity distribution agreement	7.0
Balance, December 31, 2015 and 2016	250.3

Registration Rights Agreement

The Partnership entered into an Amended and Restated Registration Rights Agreement with BPHC under which the Partnership agreed to register the resale of up to 27.9 million common units by BPHC and to reimburse BPHC up to a maximum amount of $0.914 per common unit for underwriting discounts and commissions. As of December 31, 2016 and 2015, the Partnership had an accrued liability of approximately $16.0 million for future underwriting discounts and commissions that would be reimbursed to BPHC and other registration and offering costs that are expected to be incurred by the Partnership.

Note 11: Employee Benefits

Retirement Plans

Defined Benefit Retirement Plans

Texas Gas employees hired prior to November 1, 2006, are covered under a non-contributory, defined benefit pension plan (Pension Plan). The Texas Gas Supplemental Retirement Plan (SRP) provides pension benefits for the portion of an eligible employee's pension benefit under the Pension Plan that becomes subject to compensation limitations under the Internal Revenue Code. Collectively, the Partnership refers to the Pension Plan and the SRP as Retirement Plans. The Partnership uses a measurement date of December 31 for its Retirement Plans.

As a result of the Texas Gas rate case settlement in 2006, the Partnership is required to fund the amount of annual net periodic pension cost associated with the Pension Plan, including a minimum of $3.0 million, which is the amount included in rates. In each of 2016 and 2015, the Partnership funded $3.0 million to the Pension Plan and expects to fund an additional $3.0 million to the plan in 2017. The Partnership does not anticipate that any Pension Plan assets will be returned to the Partnership during 2017. In 2016, payments of less than $0.1 million were made under the SRP. In 2015, there were no payments made under the SRP. The Partnership does not expect to fund the SRP until such time as benefits are paid.

The Partnership recognizes in expense each year the actuarially determined amount of net periodic pension cost associated with the Retirement Plans, including a minimum amount of $3.0 million related to its Pension Plan, in accordance with the 2006 rate case settlement. Texas Gas is permitted to seek future rate recovery for amounts of annual Pension Plan costs in excess of $6.0 million and is precluded from seeking future recovery of annual Pension Plan costs between $3.0 million and $6.0 million.

As a result, the Partnership would recognize a regulatory asset for amounts of annual Pension Plan costs in excess of $6.0 million and would reduce its regulatory asset to the extent that annual Pension Plan costs are less than $3.0 million. Annual Pension Plan costs between $3.0 million and $6.0 million will be charged to expense.

Postretirement Benefits Other Than Pension (PBOP)

Texas Gas provides postretirement medical benefits and life insurance to retired employees who were employed full time, hired prior to January 1, 1996, and have met certain other requirements. In 2016 and 2015, the Partnership contributed $0.2 million and $0.1 million to the PBOP plan. The PBOP plan is currently in an overfunded status; therefore, the Partnership does not expect to make any contributions to the plan in 2017. The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2017. The Partnership uses a measurement date of December 31 for its PBOP plan.

Projected Benefit Obligation, Fair Value of Assets and Funded Status

The projected benefit obligation, fair value of assets, funded status and the amounts not yet recognized as components of net periodic pension and postretirement benefits cost for the Retirement Plans and PBOP at December 31, 2016 and 2015, were as follows (in millions):

	Retirement Plans For the Year Ended December 31,		PBOP For the Year Ended December 31,	
	2016	2015	2016	2015
Change in benefit obligation:				
Benefit obligation at beginning of period	$143.8	$149.9	$48.4	$55.1
Service cost	3.6	3.8	0.3	0.3
Interest cost	4.4	4.9	2.0	2.0
Plan participants' contributions	—	—	1.0	1.1
Actuarial loss (gain)	1.6	(1.9)	(5.6)	(5.6)
Benefits paid	(0.5)	(0.5)	(4.0)	(4.5)
Settlement	(15.2)	(12.4)	—	—
Benefit obligation at end of period	$137.7	$143.8	$42.1	$48.4
Change in plan assets:				
Fair value of plan assets at beginning of period	$119.5	$130.7	$86.4	$87.3
Actual return on plan assets	8.9	(1.3)	2.3	2.4
Benefits paid	(0.5)	(0.5)	(4.0)	(4.5)
Settlement	(15.2)	(12.4)	—	—
Company contributions	3.0	3.0	0.2	0.1
Plan participants' contributions	—	—	1.0	1.1
Fair value of plan assets at end of period	$115.7	$119.5	$85.9	$86.4
Funded status	$(22.0)	$(24.3)	$43.8	$38.0
Items not recognized as components of net periodic cost:				
Prior service cost (credit)	$—	$—	$—	$(0.9)
Net actuarial loss	24.6	29.9	4.0	7.2
Total	$24.6	$29.9	$4.0	$6.3

At December 31, 2016 and 2015, the following aggregate information relates only to the underfunded plans (in millions):

	Retirement Plans For the Year Ended December 31,	
	2016	2015
Projected benefit obligation	$137.7	$143.8
Accumulated benefit obligation	128.2	134.1
Fair value of plan assets	115.7	119.5

Components of Net Periodic Benefit Cost

Components of net periodic benefit cost for both the Retirement Plans and PBOP for the years ended December 31, 2016, 2015 and 2014, were as follows (in millions):

	Retirement Plans For the Year Ended December 31,			PBOP For the Year Ended December 31,		
	2016	2015	2014	2016	2015	2014
Service cost	$3.6	$3.8	$3.9	$0.3	$0.3	$0.4
Interest cost	4.4	4.9	5.8	2.0	2.0	2.2
Expected return on plan assets	(7.9)	(9.1)	(9.5)	(4.6)	(4.6)	(4.2)
Amortization of prior service credit	—	—	—	(0.9)	(7.7)	(7.8)
Amortization of unrecognized net loss	2.7	2.0	1.4	—	—	0.3
Settlement charge	3.2	2.5	1.9	—	—	—
Net periodic benefit cost	$6.0	$4.1	$3.5	$(3.2)	$(10.0)	$(9.1)

Due to the Texas Gas rate case settlement in 2006, Texas Gas is permitted to seek future rate recovery for amounts of annual Pension Plan costs in excess of $6.0 million.

Estimated Future Benefit Payments

The following table shows benefit payments, which reflect expected future service, as appropriate, which are expected to be paid for both the Retirement Plans and PBOP (in millions):

	Retirement Plans	PBOP
2017	$ 18.4	$ 2.7
2018	12.6	2.8
2019	14.6	2.8
2020	14.5	2.9
2021	12.7	2.9
2022-2026	62.4	13.1

Weighted–Average Assumptions

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2016 and 2015, were as follows:

	Retirement Plans For the Year Ended December 31,				PBOP For the Year Ended December 31,	
	2016		2015		2016	2015
	Pension	SRP	Pension	SRP		
Discount rate	3.60%	3.85%	3.60%	4.00%	4.20%	4.25%
Expected return on plan assets	7.25%	7.25%	7.50%	7.50%	5.30%	5.30%
Rate of compensation increase	3.86%	3.86%	3.50%	3.50%	—	—

Weighted-average assumptions used to determine net periodic benefit cost for the periods indicated were as follows:

	Retirement Plans For the Year Ended December 31,						PBOP For the Year Ended December 31,		
	2016		2015		2014		2016	2015	2014
	Pension [(1)]	SRP	Pension [(2)]	SRP	Pension	SRP			
Discount rate	3.60%/ 3.45%/ 3.00%/ 2.85%	4.00%	3.35%/ 3.60%	3.75%	4.00%	4.25%	4.25%	3.90%	4.50%
Expected return on plan assets	7.25%	7.25%	7.50%	7.50%	7.50%	7.50%	5.30%	5.30%	5.30%
Rate of compensation increase	3.50%	3.50%	3.50%	3.50%	3.50%	3.50%	—	—	—

(1) Pension expense was remeasured quarterly in 2016 to reflect settlements.
(2) Pension expense was remeasured at August 31, 2015, to reflect a settlement.

The long-term rate of return for plan assets was determined based on widely-accepted capital market principles, long-term return analysis for global fixed income and equity markets as well as the active total return oriented portfolio management style. Long-term trends are evaluated relative to market factors such as inflation, interest rates and fiscal and monetary policies, in order to assess the capital market assumptions as applied to the plan. Consideration of diversification needs and rebalancing is maintained.

PBOP Assumed Health Care Cost Trends

Assumed health care cost trend rates have a significant effect on the amounts reported for PBOP. A one-percentage-point change in assumed trend rates for health care costs would have had the following effects on amounts reported for the year ended December 31, 2016 (in millions):

Effect of 1% Increase:	2016
Benefit obligation at end of year	$ 1.7
Total of service and interest costs for year	0.1
Effect of 1% Decrease:	
Benefit obligation at end of year	$ (1.5)
Total of service and interest costs for year	(0.1)

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For measurement purposes, for December 31, 2016, health care cost trend rates for the plans were assumed to remain at 7.0% for 2017-2018, grading down to 5.0% by 2021, assuming 0.5% annual increments for all participants. For December 31, 2015, health care cost trend rates for the plans were assumed to remain at 7.5% for 2016-2017, grading down to 5.0% by 2021, assuming 0.5% annual increments for all participants.

Pension Plan and PBOP Asset Allocation and Investment Strategy

Pension Plan

The Pension Plan investments are held in a trust account and consist of an undivided interest in an investment account of the Loews Corporation Employees Retirement Trust (Master Trust), established by Loews and its participating subsidiaries. Use of the Master Trust permits the co-investing of trust assets of the Pension Plan with the assets of the Loews Corporation Cash Balance Retirement Plan for investment and administrative purposes. Although assets of all plans are co-invested in the Master Trust, the custodian maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the participating plans. The net investment income of the investment assets is allocated by the custodian to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. The Master Trust assets are measured at fair value. The fair value of the interest in the assets of the Master Trust associated with the Pension Plan as of December 31, 2016 and 2015, was $115.7 million (or 50.3%) and $119.5 million (or 51.0%), of the total Master Trust assets.

Equity securities are publicly traded securities which are valued using quoted market prices and are considered a Level 1 investment under the fair value hierarchy. Short-term investments that are actively traded or have quoted prices, such as money market funds, are considered Level 1 investments. Fixed income mutual funds are highly liquid and exchange traded, valued using quoted market prices, and are considered a Level 1 investment. Corporate and other taxable bonds and asset-backed securities are valued using pricing for similar securities, recently executed transactions, cash flow models with yield curves, broker/dealer quotes and other pricing models utilizing observable inputs and are considered Level 2 investments. The limited partnership investments held within the Master Trust are recorded at fair value, which represents the Master Trust's shares of the net asset value of each partnership, as determined by the general partner. The limited partnership and other invested assets consist primarily of hedge fund strategies that generate returns through investing in marketable securities in the public fixed income and equity markets.

The following table sets forth, by level within the fair value hierarchy, a summary of the Master Trust's investments measured at fair value on a recurring basis at December 31, 2016 (in millions):

	Master Trust Assets Measured under Fair Value Hierarchy				Measured at Net Asset Value	Total Master Trust Assets
	Level 1	Level 2	Level 3	Total		
Equity securities	$40.6	$ —	$ —	$40.6	$ —	$40.6
Short-term investments	6.7	—	—	6.7	—	6.7
Fixed income mutual funds	93.1	—	—	93.1	—	93.1
Asset-backed securities	—	7.1	—	7.1	—	7.1
Total assets measured at fair value	140.4	7.1	—	147.5	—	147.5
Total limited partnerships measured at net asset value (1)	—	—	—	—	82.5	82.5
Total	$140.4	$7.1	$ —	$147.5	$ 82.5	$230.0

The following table sets forth, by level within the fair value hierarchy, a summary of the Master Trust's investments measured at fair value on a recurring basis at December 31, 2015 (in millions):

	Master Trust Assets Measured under Fair Value Hierarchy				Measured at Net Asset Value	Total Master Trust Assets
	Level 1	Level 2	Level 3	Total		
Equity securities	$36.1	$—	$ —	$36.1	$ —	$36.1
Short-term investments	6.6	—	—	6.6	—	6.6
Fixed income mutual funds	94.8	—	—	94.8	—	94.8
Asset-backed securities	—	6.4	—	6.4	—	6.4
Total assets measured at fair value	137.5	6.4	—	143.9	—	143.9
Total limited partnerships measured at net asset value (1)	—	—	—	—	90.4	90.4
Total	$137.5	$6.4	$ —	$143.9	$ 90.4	$234.3

(1) In May 2015, the FASB issued Accounting Standards Update No. 2015-07, "Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or its Equivalent)" (ASU 2015-07), which removes the requirement to present certain investments that are measured at fair value using the net asset value per share (or its equivalent) practical expedient within the fair value hierarchy table. The fair value amounts presented in the tables above are intended to permit reconciliation of the fair value hierarchy to the amounts presented in the statement of financial position. The Partnership adopted ASU 2015-07 as of December 31, 2016, and has retrospectively applied ASU 2015-07 as required. Other than the presentation of the investments measured at net asset value, there were no effects to the reported amounts presented for the Master Trust as of December 31, 2015.

PBOP

The PBOP plan assets are held in a trust and are measured at fair value. Short-term investments that are actively traded or have quoted prices, such as money market or mutual funds, are considered Level 1 investments. Fixed income mutual funds are actively traded and valued using quoted market prices and are considered Level 1 investments. Tax exempt securities, consisting of municipal securities, corporate and other taxable bonds and asset-backed securities are valued using pricing for similar securities, recently executed transactions, cash flow models with yield curves, broker/dealer quotes and other pricing models utilizing observable inputs and are considered Level 2 investments.

The following table sets forth, by level within the fair value hierarchy, a summary of the PBOP trust investments measured at fair value on a recurring basis at December 31, 2016 (in millions):

	PBOP Trust Assets			
	Level 1	Level 2	Level 3	Total
Short-term investments	$3.2	$—	$ —	$3.2
Fixed income mutual funds	4.9	—	—	4.9
Asset-backed securities	—	15.5	—	15.5
Corporate bonds	—	18.6	—	18.6
Tax exempt securities	—	43.7	—	43.7
Total investments	$8.1	$77.8	$ —	$85.9

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The following table sets forth, by level within the fair value hierarchy, a summary of the PBOP trust investments measured at fair value on a recurring basis at December 31, 2015 (in millions):

	PBOP Trust Assets			
	Level 1	Level 2	Level 3	Total
Short-term investments	$3.0	$—	$ —	$3.0
Fixed income mutual funds	4.7	—	—	4.7
Asset-backed securities	—	18.8	—	18.8
Corporate bonds	—	17.0	—	17.0
Tax exempt securities	—	42.9	—	42.9
Total investments	$7.7	$78.7	$ —	$86.4

Investment strategy

Pension Plan: The Partnership employs a total-return approach using a mix of equities and fixed income investments to maximize the long-term return on plan assets for a prudent level of risk and generate cash flows adequate to meet plan requirements. The intent of this strategy is to minimize plan expenses by outperforming plan liabilities over the long run. Risk tolerance is established through careful consideration of the plan liabilities, plan funded status and corporate financial conditions. The investment strategy has been to allocate 40% to 60% of the investment portfolio to equity and alternative investments, including limited partnerships, with the remainder primarily invested in fixed income securities. The investment portfolio contains a diversified blend of fixed income, equity and short-term securities. Alternative investments, including limited partnerships, have been used to enhance risk adjusted long-term returns while improving portfolio diversification. At December 31, 2016, the pension trust had committed $6.3 million to future capital calls from various third party limited partnership investments in exchange for an ownership interest in the related partnerships. Investment risk is monitored through annual liability measurements, periodic asset and liability studies and quarterly investment portfolio reviews.

PBOP: The investment strategy for the PBOP assets is to reduce the volatility of plan investments while protecting the initial investment given the overfunded status of the plan. At December 31, 2016 and 2015, all of the PBOP investments were in fixed income securities.

Defined Contribution Plans

Texas Gas employees hired on or after November 1, 2006, and all other employees of the Partnership are provided retirement benefits under a defined contribution money purchase plan. The Partnership also provides 401(k) plan benefits to their employees. Costs related to the Partnership's defined contribution plans were $10.7 million, $9.8 million and $9.0 million for the years ended December 31, 2016, 2015 and 2014.

Long-Term Incentive Compensation Plans

The Partnership grants to selected employees long-term compensation awards under the LTIP and the UAR and Cash Bonus Plan. These awards are intended to align the interests of the employees with those of the Partnership's unitholders, encourage superior performance, attract and retain employees who are essential for the Partnership's growth and profitability and to encourage employees to devote their best efforts to advancing the Partnership's business over both long and short-term time horizons. The Partnership also makes annual grants of common units to certain of its directors under the LTIP.

LTIP

The Partnership reserved 3,525,000 common units for grants of units, restricted units, unit options and UARs to officers and directors of the Partnership's general partner and for selected employees under the LTIP. The Partnership has outstanding Phantom Common Units which were granted under the plan. Each outstanding Phantom Common Unit includes a tandem grant of Distribution Equivalent Rights (DERs). The grantee must select one of two irrevocable payment elections shortly after the award is granted. If the first payment election is selected, an amount equal to the fair market value of the vested portion of the Phantom Common Units (as defined in the plan) and associated DERs will become payable to the grantee in cash on each of the two vesting dates. If the second payment election option is selected, the Phantom Common Units and associated DERs will become payable in cash on the second vesting date. The economic value of the Phantom Common Units is directly tied to the value of the Partnership's common units, but these awards do not confer any rights of ownership to the grantee. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement based on the market price of the

Partnership's common units and amounts credited under the DERs. Except for the annual grants of common units to certain of its directors, the Partnership has not made any grants of units, restricted units or unit options under the plan.

A summary of the status of the Phantom Common Units granted under the Partnership's LTIP as of December 31, 2016 and 2015, and changes during the years ended December 31, 2016 and 2015, is presented below:

	Phantom Common Units	Total Fair Value (in millions)	Weighted-Average Vesting Period (in years)
Outstanding at January 1, 2015 (1)	199,669	$ 4.1	0.9
Granted	647,256	10.1	2.4
Paid	(196,748)	(2.9)	—
Forfeited	(4,209)	—	—
Outstanding at December 31, 2015 (1)	645,968	8.7	1.5
Granted	865,091	10.2	2.3
Paid	(237,972)	(4.1)	—
Forfeited	(15,462)	—	—
Outstanding at December 31, 2016 (1)	1,257,625	$ 22.5	1.2

(1) Represents fair value and remaining weighted-average vesting period of outstanding awards at the end of the period.

The fair value of the awards at the date of grant was based on the closing market price of the Partnership's common units on or directly preceding the date of grant. The fair value of the awards at December 31, 2016 and 2015, was based on the closing market price of the common unit on those dates of $17.36 and $12.98 plus the accumulated value of the DERs. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities, and taking into account the payment elections selected by the grantees. The Partnership recorded $11.6 million, $3.6 million and $1.2 million in Administrative and general expenses during 2016, 2015 and 2014 for the Phantom Common Unit awards. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2016 and 2015, was $11.9 million and $5.5 million.

In 2016 and 2015, the general partner purchased 17,108 and 12,180 of the Partnership's common units in the open market at a price of $11.75 and $16.57 per unit. These units were granted under the LTIP to the independent directors as part of their director compensation. At December 31, 2016, 3,460,872 units were available for grants under the LTIP.

UAR and Cash Bonus Plan

The UAR and Cash Bonus Plan provides for grants of UARs and Long-Term Cash Bonuses to selected employees of the Partnership. In 2014, the Partnership granted to certain employees $9.2 million of Long-Term Cash Bonuses, which vested and were paid in 2016. The Partnership recorded compensation expense of $3.5 million, $2.8 million and $2.6 million for the years ended December 31, 2016, 2015 and 2014, related to the Long-Term Cash Bonuses. As of December 31, 2016, the Partnership had no remaining unrecognized compensation cost related to the Long-Term Cash Bonuses and had no outstanding UARs.

Retention Payment Agreements

In 2014, the Partnership entered into retention payment agreements with certain key employees. The total amount of cash payable under the program would be approximately $12.0 million, subject to the employees remaining employed by the Partnership over a period of three years and other conditions. Each retention payment agreement will vest and become payable in cash as follows: 25% vested and became payable on February 28, 2015, 25% vested and became payable on February 29, 2016, and the remaining 50% will vest and become payable on February 28, 2017. Except in limited circumstances, upon termination of employment during the vesting period, any outstanding and unvested retention payments would be cancelled unpaid. Retention payments of $2.9 million were made in 2016 and 2015. The Partnership recorded compensation expense of $2.2 million, $3.8 million and $4.8 million for the years ended December 31, 2016, 2015 and 2014, and as of December 31, 2016, there was $0.9 million of total unrecognized compensation expense related to the retention payment agreements.

Note 12: Cash Distributions and Net Income per Unit

Cash Distributions

The Partnership's cash distribution policy requires that the Partnership distribute to its various ownership interests on a quarterly basis all of its available cash, as defined in its partnership agreement. IDRs, which represent a limited partner ownership interest and are currently held by the Partnership's general partner, represent the contractual right to receive an increasing percentage of quarterly distributions of available cash as follows:

	Total Quarterly Distributions	Marginal Percentage Interest in Distributions	
	Target Amount	Limited Partner Unitholders	General Partner and IDRs
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target Distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	above $0.5250	50%	50%

The Partnership has declared quarterly distributions per unit to unitholders of record and the 2% general partner interest and IDRs held by its general partner as follows (in millions, except distribution per unit):

Payment Date	Distribution per Unit	Amount Paid to Common Unitholders	Amount Paid to General Partner (Including IDRs) (1)
November 17, 2016	$ 0.1000	$ 25.0	$ 0.5
August 18, 2016	0.1000	25.1	0.5
May 19, 2016	0.1000	25.1	0.5
February 25, 2016	0.1000	25.0	0.5
November 19, 2015	0.1000	25.0	0.5
August 20, 2015	0.1000	25.1	0.5
May 21, 2015	0.1000	25.1	0.5
February 26, 2015	0.1000	24.3	0.5
November 20, 2014	0.1000	24.3	0.5
August 21, 2014	0.1000	24.3	0.5
May 15, 2014	0.1000	24.3	0.5
February 27, 2014	0.1000	24.3	0.5

(1) For 2016, 2015 and 2014, the quarterly target distribution levels for IDR payout were not met and the Partnership paid no amounts with respect to the IDRs.

In February 2017, the Partnership declared a quarterly cash distribution to unitholders of record of $0.10 per common unit.

Net Income per Unit

For purposes of calculating net income per unit, net income for the current period is reduced by the amount of available cash that will be distributed with respect to that period. Any residual amount representing undistributed net income (or loss) is assumed to be allocated to the various ownership interests in accordance with the contractual provisions of the partnership agreement.

Under the Partnership's partnership agreement, for any quarterly period, the IDRs participate in net income only to the extent of the amount of cash distributions actually declared, thereby excluding the IDRs from participating in undistributed net income or losses. Accordingly, undistributed net income is assumed to be allocated to the other ownership interests on a pro rata basis. Payments made on account of the Partnership's various ownership interests are determined in relation to actual declared distributions, and are not based on the assumed allocations required under GAAP. Unless noted otherwise, basic and diluted net income per unit are the same.

The following table provides a reconciliation of net income and the assumed allocation of net income to the common units for purposes of computing net income per unit for the year ended December 31, 2016 (in millions, except per unit data):

	Total	Common Units	General Partner and IDRs
Net income	$302.2		
Declared distribution	102.2	$ 100.2	$ 2.0
Assumed allocation of undistributed net income	200.0	196.0	4.0
Assumed allocation of net income attributable to limited partner unitholders and general partner	$302.2	$ 296.2	$ 6.0
Weighted-average units outstanding		250.3	
Net income per unit		$ 1.18	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common units for purposes of computing net income per unit for the year ended December 31, 2015 (in millions, except per unit data):

	Total	Common Units	General Partner and IDRs
Net income	$222.0		
Declared distribution	102.2	$ 100.2	$ 2.0
Assumed allocation of undistributed net income	119.8	117.3	2.5
Assumed allocation of net income attributable to limited partner unitholders and general partner	$222.0	$ 217.5	$ 4.5
Weighted-average units outstanding		248.8	
Net income per unit		$ 0.87	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common units for purposes of computing net income per unit for the year ended December 31, 2014 (in millions, except per unit data):

	Total	Common Units	General Partner and IDRs
Net income	$146.8		
Less: Net loss attributable to noncontrolling interests	(86.8)		
Net income attributable to controlling interests	233.6		
Declared distribution	99.2	$ 97.2	$ 2.0

Assumed allocation of undistributed net income	134.4	131.7	2.7
Assumed allocation of net income attributable to limited partner unitholders and general partner	$233.6	$ 228.9	$ 4.7
Weighted-average units outstanding		243.3	
Net income per unit		$ 0.94	

Note 13: Income Taxes

The Partnership is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. The Partnership's taxable income or loss, which may vary substantially from the net income or loss reported in the Consolidated Statements of Income, is includable in the federal income tax returns of each partner. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in Income taxes on the Consolidated Statements of Income.

Following is a summary of the provision for income taxes for the periods ended December 31, 2016, 2015 and 2014 (in millions):

	For the Year Ended December 31,		
	2016	2015	2014
Current expense:			
State	$0.4	$0.4	$0.3
Total	0.4	0.4	0.3
Deferred provision:			
State	0.2	0.1	0.1
Total	0.2	0.1	0.1
Income taxes	$0.6	$0.5	$0.4

The Partnership's tax years 2013 through 2016 remain subject to examination by the Internal Revenue Service and the states in which it operates. There were no differences between the provision at the statutory rate to the income tax provision at December 31, 2016, 2015 and 2014. As of December 31, 2016 and 2015, there were no significant deferred income tax assets or liabilities.

Note 14: Credit Risk

Major Customers

For the years ended December 31, 2016 and 2015, no customer comprised 10% or more of the Partnership's operating revenues. For the year ended December 31, 2014, the Partnership earned $120.5 million of operating revenues from Devon Gas Services, LP, which represented 10% of total operating revenues.

Natural gas producers comprise a significant portion of the Partnership's revenues and support several of the Partnership's growth projects. In 2016, approximately 46% of revenues were generated from contracts with natural gas producers. In periods of low or volatile natural gas and oil prices, the Partnership could be exposed to increased credit risk associated with its producer customer group. The Partnership actively monitors its customer credit profiles, as well as the portion of revenues generated from investment-grade and non-investment-grade customers.

Gas Loaned to Customers

Natural gas price volatility can cause changes in credit risk related to gas and NGLs loaned to customers. As of December 31, 2016, the amount of gas owed to the operating subsidiaries due to gas imbalances and gas loaned under PAL agreements was approximately 13.6 trillion British thermal units (TBtu). Assuming an average market price during December 2016 of $3.47 per million British thermal units (MMBtu), the market value of that gas was approximately $47.2 million. As of December 31, 2016, the amount of NGLs owed to the operating subsidiaries due to imbalances was less than 0.1 million barrels (MMBbls), which had a market value of approximately $0.4 million. As of December 31, 2015, the amount of gas owed to the operating subsidiaries due to gas imbalances and gas loaned under PAL agreements was approximately 7.7 TBtu. Assuming an average market price during December 2015 of $1.86 per MMBtu, the market value of that gas at December 31, 2015, would have been approximately $14.3 million. As of December 31, 2015, the amount of NGLs owed to the operating subsidiaries due to imbalances was less than 0.1 MMBbls, which had a market value of approximately $0.2 million. If any significant customer should have credit or financial problems resulting in a delay or failure to repay the gas owed to the operating subsidiaries, it could have a material adverse effect on the Partnership's financial condition, results of operations or cash flows.

Note 15: Related Party Transactions

Loews provides a variety of corporate services to the Partnership under services agreements, including but not limited to, information technology, tax, risk management, internal audit and corporate development services and also charges the Partnership for allocated overheads. The Partnership incurred charges related to these services of $7.1 million, $8.8 million and $8.8 million for the years ended December 31, 2016, 2015 and 2014.

Distributions paid related to limited partner units held by BPHC and the 2% general partner interest held by Boardwalk GP were $52.2 million, $52.2 million and $52.0 million for the years ended December 31, 2016, 2015 and 2014.

In 2014, the Partnership and BPHC entered into a Subordinated Loan Agreement whereby the Partnership can borrow up to $300.0 million. Note 10 contains more information related to the affiliated long-term debt.

In 2013, the Partnership entered into agreements with BPHC to form two entities for the purpose of investing in the Bluegrass Project. For the year ended December 31, 2014, the Partnership contributed $0.8 million and BPHC contributed $8.2 million of cash and other assets to these entities. In 2014, the Partnership and BPHC dissolved these entities, resulting in the Partnership receiving $2.2 million in distributions and BPHC receiving $7.9 million in distributions. Refer to Note 3 for further information on the Bluegrass Project.

Note 16: Supplemental Disclosure of Cash Flow Information (in millions):

	For the Year Ended December 31,		
	2016	2015	2014
Cash paid during the period for:			
Interest (net of amount capitalized)	$170.6	$170.6	$153.0
Income taxes, net	0.7	0.3	0.1
Non-cash adjustments:			
Accounts payable and PPE	93.4	54.7	36.9

Note 17: Selected Quarterly Financial Data (Unaudited)

The following tables summarize selected quarterly financial data for 2016 and 2015 for the Partnership (in millions, except for earnings per unit):

	2016			
	For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$352.6	$ 303.3	$306.3	$345.0
Operating expenses	219.7	209.6	197.0	203.4
Operating income	132.9	93.7	109.3	141.6
Interest expense, net	46.3	48.3	45.3	42.5
Other income	(1.8)	(1.9)	(1.9)	(2.1)
Income before income taxes	88.4	47.3	65.9	101.2
Income taxes	0.2	—	0.2	0.2

Net income	$88.2	$ 47.3	$65.7	$101.0
Net income per unit	$0.34	$ 0.19	$0.26	$0.40

	2015			
	For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$326.8	$ 294.1	$298.6	$329.7
Operating expenses	220.4	213.4	212.7	206.9
Operating income	106.4	80.7	85.9	122.8
Interest expense, net	42.1	43.0	45.8	45.1
Other income	(1.4)	(0.7)	(0.4)	(0.2)
Income before income taxes	65.7	38.4	40.5	77.9
Income taxes	0.1	0.1	0.1	0.2
Net income	$65.6	$ 38.3	$40.4	$77.7
Net income per unit	$0.26	$ 0.15	$0.16	$0.31

Note 18: Guarantee of Securities of Subsidiaries

Boardwalk Pipelines (Subsidiary Issuer) has issued securities which have been fully and unconditionally guaranteed by the Partnership (Parent Guarantor). The Subsidiary Issuer is 100% owned by the Parent Guarantor. The Partnership's subsidiaries have no significant restrictions on their ability to pay distributions or make loans to the Partnership except as noted in the debt covenants and have no restricted assets at December 31, 2016 and 2015. Note 10 contains additional information regarding the Partnership's debt and related covenants.

Condensed Consolidating Balance Sheets as of December 31, 2016
(Millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash and cash equivalents	$ 0.6	$ 1.8	$ 2.2	$ —	$ 4.6
Receivables	—	—	139.8	—	139.8
Receivables - affiliate	—	—	7.0	(7.0)	—
Gas and liquids stored underground	—	—	1.3	—	1.3
Prepayments	0.4	—	17.3	—	17.7
Advances to affiliates	—	72.9	102.7	(175.6)	—
Other current assets	—	—	13.9	(3.1)	10.8
Total current assets	1.0	74.7	284.2	(185.7)	174.2
Investment in consolidated subsidiaries	2,423.2	6,653.6	—	(9,076.8)	—
Property, plant and equipment, gross	0.6	—	10,326.7	—	10,327.3
Less–accumulated depreciation and amortization	0.6	—	2,333.2	—	2,333.8
Property, plant and equipment, net	—	—	7,993.5	—	7,993.5
Other noncurrent assets	—	3.3	466.8	—	470.1
Advances to affiliates – noncurrent	2,125.0	435.0	229.3	(2,789.3)	—
Total other assets	2,125.0	438.3	696.1	(2,789.3)	470.1
Total Assets	$ 4,549.2	$ 7,166.6	$ 8,973.8	$ (12,051.8)	$ 8,637.8

Liabilities and Partners' Capital	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Payables	$ 0.9	$ 0.2	$ 136.4	$ —	$ 137.5
Payable to affiliates	1.4	—	7.0	(7.0)	1.4
Advances from affiliates	—	102.7	72.9	(175.6)	—
Other current liabilities	—	21.8	175.3	(3.1)	194.0
Total current liabilities	2.3	124.7	391.6	(185.7)	332.9
Long-term debt and capital lease obligation	—	2,264.4	1,293.6	—	3,558.0
Payable to affiliate - noncurrent	16.0	—	—	—	16.0
Advances from affiliates - noncurrent	—	2,354.3	435.0	(2,789.3)	—
Other noncurrent liabilities	—	—	200.0	—	200.0
Total other liabilities and deferred credits	16.0	2,354.3	635.0	(2,789.3)	216.0
Total partners' capital	4,530.9	2,423.2	6,653.6	(9,076.8)	4,530.9
Total Liabilities and Partners' Capital	$ 4,549.2	$ 7,166.6	$ 8,973.8	$ (12,051.8)	$ 8,637.8

Condensed Consolidating Balance Sheets as of December 31, 2015
(Millions)

Assets	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Cash and cash equivalents	$—	$0.3	$ 2.8	$—	$ 3.1
Receivables	—	—	129.5	—	129.5
Receivables - affiliate	—	—	7.0	(7.0)	—
Gas and liquids stored underground	—	—	10.7	—	10.7
Prepayments	0.2	—	16.7	—	16.9
Advances to affiliates	—	21.0	107.7	(128.7)	—
Other current assets	—	—	12.8	(3.2)	9.6
Total current assets	0.2	21.3	287.2	(138.9)	169.8
Investment in consolidated subsidiaries	2,153.5	7,067.6	—	(9,221.1)	—
Property, plant and equipment, gross	0.6	—	9,706.0	—	9,706.6
Less–accumulated depreciation and amortization	0.6	—	2,051.6	—	2,052.2
Property, plant and equipment, net	—	—	7,654.4	—	7,654.4
Other noncurrent assets	0.4	3.0	472.7	—	476.1
Advances to affiliates – noncurrent	2,190.2	466.3	1,113.4	(3,769.9)	—
Total other assets	2,190.6	469.3	1,586.1	(3,769.9)	476.1
Total Assets	$4,344.3	$7,558.2	$ 9,527.7	$(13,129.9)	$ 8,300.3

Liabilities and Partners' Capital	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Payables	$0.3	$0.1	$ 118.2	$—	$ 118.6
Payable to affiliates	1.3	—	7.0	(7.0)	1.3
Advances from affiliates	—	107.7	21.0	(128.7)	—
Other current liabilities	—	20.9	176.8	(3.2)	194.5
Total current liabilities	1.6	128.7	323.0	(138.9)	314.4
Long-term debt and capital lease obligation	—	1,972.4	1,486.9	—	3,459.3
Payable to affiliate - noncurrent	16.0	—	—	—	16.0
Advances from affiliates - noncurrent	—	3,303.6	466.3	(3,769.9)	—
Other noncurrent liabilities	—	—	183.9	—	183.9
Total other liabilities and deferred credits	16.0	3,303.6	650.2	(3,769.9)	199.9
Total partners' capital	4,326.7	2,153.5	7,067.6	(9,221.1)	4,326.7
Total Liabilities and Partners' Capital	$4,344.3	$7,558.2	$ 9,527.7	$(13,129.9)	$ 8,300.3

Condensed Consolidating Statements of Income for the Year Ended December 31, 2016
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating Revenues:					
Transportation	$ —	$ —	$ 1,230.2	$ (87.8)	$ 1,142.4
Parking and lending	—	—	20.1	(1.9)	18.2
Storage	—	—	91.4	—	91.4
Other	—	—	55.2	—	55.2
Total operating revenues	—	—	1,396.9	(89.7)	1,307.2
Operating Costs and Expenses:					
Fuel and transportation	—	—	160.5	(89.7)	70.8
Operation and maintenance	—	—	199.9	—	199.9
Administrative and general	0.5	—	141.7	—	142.2
Other operating costs and expenses	0.4	—	416.4	—	416.8
Total operating costs and expenses	0.9	—	918.5	(89.7)	829.7
Operating (loss) income	(0.9)	—	478.4	—	477.5
Other Deductions (Income):					
Interest expense	—	123.8	59.0	—	182.8
Interest (income) expense-affiliates, net	(37.8)	44.4	(6.6)	—	—
Interest income	—	(0.1)	(0.3)	—	(0.4)
Equity in earnings of subsidiaries	(265.5)	(433.6)	—	699.1	—
Miscellaneous other income, net	0.2	—	(7.9)	—	(7.7)
Total other (income) deductions	(303.1)	(265.5)	44.2	699.1	174.7
Income (loss) before income taxes	302.2	265.5	434.2	(699.1)	302.8
Income taxes	—	—	0.6	—	0.6
Net income (loss)	$ 302.2	$ 265.5	$ 433.6	$ (699.1)	$ 302.2

Condensed Consolidating Statements of Income for the Year Ended December 31, 2015
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating Revenues:					
Transportation	$ —	$ —	$ 1,178.5	$ (87.4)	$ 1,091.1
Parking and lending	—	—	11.6	(0.2)	11.4
Storage	—	—	81.3	—	81.3
Other	—	—	65.4	—	65.4
Total operating revenues	—	—	1,336.8	(87.6)	1,249.2
Operating Costs and Expenses:					
Fuel and transportation	—	—	186.9	(87.6)	99.3
Operation and maintenance	—	—	209.5	—	209.5
Administrative and general	—	—	130.4	—	130.4
Other operating costs and expenses	0.3	—	413.9	—	414.2
Total operating costs and expenses	0.3	—	940.7	(87.6)	853.4
Operating (loss) income	(0.3)	—	396.1	—	395.8
Other Deductions (Income):					
Interest expense	—	104.0	72.4	—	176.4
Interest (income) expense - affiliates, net	(28.8)	38.2	(9.4)	—	—
Interest income	—	—	(0.4)	—	(0.4)
Equity in earnings of subsidiaries	(193.5)	(335.7)	—	529.2	—
Miscellaneous other income, net	—	—	(2.7)	—	(2.7)
Total other (income) deductions	(222.3)	(193.5)	59.9	529.2	173.3
Income (loss) before income taxes	222.0	193.5	336.2	(529.2)	222.5
Income taxes	—	—	0.5	—	0.5
Net income (loss)	$ 222.0	$ 193.5	$ 335.7	$ (529.2)	$ 222.0

Condensed Consolidating Statements of Income for the Year Ended December 31, 2014
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Operating Revenues:					
Transportation	$ —	$ —	$ 1,157.9	$ (92.8)	$ 1,065.1
Parking and lending	—	—	23.3	—	23.3
Storage	—	—	90.4	(0.9)	89.5
Other	—	—	55.9	—	55.9
Total operating revenues	—	—	1,327.5	(93.7)	1,233.8
Operating Costs and Expenses:					
Fuel and transportation	—	—	218.4	(93.7)	124.7
Operation and maintenance	—	—	194.8	—	194.8
Administrative and general	0.2	—	124.8	—	125.0
Other operating costs and expenses	0.2	—	391.0	—	391.2
Total operating costs and expenses	0.4	—	929.0	(93.7)	835.7
Operating (loss) income	(0.4)	—	398.5	—	398.1
Other Deductions (Income):					
Interest expense	—	76.5	89.0	—	165.5
Interest (income) expense - affiliates, net	(30.0)	41.2	(11.2)	—	—
Interest income	—	—	(0.6)	—	(0.6)
Equity in earnings of subsidiaries	(204.0)	(321.7)	—	525.7	—
Equity losses in unconsolidated affiliates	—	—	86.5	—	86.5
Miscellaneous other income, net	—	—	(0.5)	—	(0.5)
Total other (income) deductions	(234.0)	(204.0)	163.2	525.7	250.9
Income (loss) before income taxes	233.6	204.0	235.3	(525.7)	147.2
Income taxes	—	—	0.4	—	0.4
Net income (loss)	233.6	204.0	234.9	(525.7)	146.8
Net loss attributable to noncontrolling interests	—	—	(86.8)	—	(86.8)
Net income (loss) attributable to controlling interests	$ 233.6	$ 204.0	$ 321.7	$ (525.7)	$ 233.6

Condensed Consolidating Statements of Comprehensive Income for the Year Ended December 31, 2016
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net income (loss)	$ 302.2	$ 265.5	$ 433.6	$ (699.1)	$ 302.2
Other comprehensive income (loss):					
Reclassification adjustment transferred to Net income from cash flow hedges	2.4	2.4	0.7	(3.1)	2.4
Pension and other postretirement benefit costs	1.8	1.8	1.8	(3.6)	1.8
Total Comprehensive Income (Loss)	$ 306.4	$ 269.7	$ 436.1	$ (705.8)	$ 306.4

Condensed Consolidating Statements of Comprehensive Income for the Year Ended December 31, 2015
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net income (loss)	$ 222.0	$ 193.5	$ 335.7	$ (529.2)	$ 222.0
Other comprehensive (loss) income:					
Reclassification adjustment transferred to Net income from cash flow hedges	2.4	2.4	0.7	(3.1)	2.4
Pension and other postretirement benefit costs	(13.9)	(13.9)	(13.9)	27.8	(13.9)
Total Comprehensive Income (Loss)	$ 210.5	$ 182.0	$ 322.5	$ (504.5)	$ 210.5

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Condensed Consolidating Statements of Comprehensive Income for the Year Ended December 31, 2014
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net income (loss)	$ 233.6	$ 204.0	$ 234.9	$ (525.7)	$ 146.8
Other comprehensive (loss) income:					
(Loss) gain on cash flow hedges	(0.7)	(0.7)	(0.7)	1.4	(0.7)
Reclassification adjustment transferred to Net Income from cash flow hedges	2.6	2.6	0.9	(3.5)	2.6
Pension and other postretirement benefit costs	(10.9)	(10.9)	(10.9)	21.8	(10.9)
Total Comprehensive Income (Loss)	224.6	195.0	224.2	(506.0)	137.8
Comprehensive loss attributable to noncontrolling interests	—	—	(86.8)	—	(86.8)
Comprehensive income (loss) attributable to controlling interests	$ 224.6	$ 195.0	$ 311.0	$ (506.0)	$ 224.6

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Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2016
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net cash provided by (used in) operating activities	$ 37.3	$ (161.9)	$ 725.4	$ —	$ 600.8
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(590.4)	—	(590.4)
Proceeds from sale of operating assets	—	—	0.2	—	0.2
Advances to affiliates, net	65.2	(20.6)	39.1	(83.7)	—
Net cash provided by (used in) investing activities	65.2	(20.6)	(551.1)	(83.7)	(590.2)
FINANCING ACTIVITIES:					
Proceeds from long-term debt, net of issuance cost	—	539.1	—	—	539.1
Repayment of borrowings from long-term debt and term loan	—	(250.0)	—	—	(250.0)
Proceeds from borrowings on revolving credit agreement	—	—	490.0	—	490.0
Repayment of borrowings on revolving credit agreement, including financing fees	—	(0.8)	(685.0)	—	(685.8)
Principal payment of capital lease obligation	—	—	(0.5)	—	(0.5)
Advances from affiliates, net	0.3	(104.3)	20.6	83.7	0.3
Distributions paid	(102.2)	—	—	—	(102.2)
Net cash (used in) provided by financing activities	(101.9)	184.0	(174.9)	83.7	(9.1)
Increase (decrease) in cash and cash equivalents	0.6	1.5	(0.6)	—	1.5
Cash and cash equivalents at beginning of period	—	0.3	2.8	—	3.1
Cash and cash equivalents at end of period	$ 0.6	$ 1.8	$ 2.2	$ —	$ 4.6

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2015
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net cash provided by (used in) operating activities	$ 27.9	$ (136.3)	$ 684.8	$ —	$ 576.4
INVESTING ACTIVITIES:					
Capital expenditures	(1.0)	—	(373.5)	—	(374.5)
Proceeds from sale of operating assets	—	—	0.8	—	0.8
Proceeds from other recoveries	—	—	6.2	—	6.2
Advances to affiliates, net	(41.9)	(269.0)	(118.4)	429.3	—
Net cash (used in) provided by investing activities	(42.9)	(269.0)	(484.9)	429.3	(367.5)
FINANCING ACTIVITIES:					
Proceeds from long-term debt, net of issuance cost	—	247.1	—	—	247.1
Repayment of borrowings from long-term debt and term loan	—	—	(725.0)	—	(725.0)
Proceeds from borrowings on revolving credit agreement	—	—	1,125.0	—	1,125.0
Repayment of borrowings on revolving credit agreement, including financing fees	—	(3.6)	(870.0)	—	(873.6)
Principal payment of capital lease obligation	—	—	(0.4)	—	(0.4)
Advances from affiliates, net	0.6	160.3	269.0	(429.3)	0.6
Distributions paid	(101.5)	—	—	—	(101.5)
Proceeds from sale of common units	113.1	—	—	—	113.1
Capital contributions from general partner	2.3	—	—	—	2.3
Net cash provided by (used in) financing activities	14.5	403.8	(201.4)	(429.3)	(212.4)
Decrease in cash and cash equivalents	(0.5)	(1.5)	(1.5)	—	(3.5)
Cash and cash equivalents at beginning of period	0.5	1.8	4.3	—	6.6
Cash and cash equivalents at end of period	$ —	$ 0.3	$ 2.8	$ —	$ 3.1

Condensed Consolidating Statements of Cash Flow for the Year Ended December 31, 2014
(Millions)

	Parent Guarantor	Subsidiary Issuer	Non-guarantor Subsidiaries	Eliminations	Consolidated Boardwalk Pipeline Partners, LP
Net cash provided by (used in) operating activities	$ 30.2	$ (112.1)	$ 595.5	$ —	$ 513.6
INVESTING ACTIVITIES:					
Capital expenditures	—	—	(404.4)	—	(404.4)
Proceeds from sale of operating assets	—	—	2.9	—	2.9
Proceeds from insurance and other recoveries	—	—	6.3	—	6.3
Advances to affiliates, net	363.9	(49.6)	(175.2)	(139.0)	0.1
Investment in unconsolidated affiliates	—	—	(20.5)	—	(20.5)
Distributions from unconsolidated affiliates	—	—	11.1	—	11.1
Acquisition of businesses, net of cash acquired	(294.7)	—	—	—	(294.7)
Net cash provided by (used in) investing activities	69.2	(49.6)	(579.8)	(139.0)	(699.2)
FINANCING ACTIVITIES:					
Proceeds from long-term debt, net of issuance cost	—	342.9	—	—	342.9
Repayment of borrowings from term loan	—	—	(25.0)	—	(25.0)
Proceeds from borrowings on revolving credit agreement	—	—	665.0	—	665.0
Repayment of borrowings on revolving credit agreement	—	—	(720.0)	—	(720.0)
Principal payment of capital lease obligation	—	—	(0.4)	—	(0.4)
Advances from affiliates, net	0.1	(188.6)	49.6	139.0	0.1
Distributions paid	(99.2)	—	—	—	(99.2)
Capital contributions from noncontrolling interests	—	—	8.2	—	8.2
Distributions paid to noncontrolling interests	—	—	(7.9)	—	(7.9)
Net cash (used in) provided by financing activities	(99.1)	154.3	(30.5)	139.0	163.7
Increase (decrease) in cash and cash equivalents	0.3	(7.4)	(14.8)	—	(21.9)
Cash and cash equivalents at beginning of period	0.2	9.2	19.1	—	28.5
Cash and cash equivalents at end of period	$ 0.5	$ 1.8	$ 4.3	$ —	$ 6.6

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Report. Our disclosure controls and procedures are designed to allow timely decisions regarding required disclosure and to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the Commission. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective as of December 31, 2016, at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended December 31, 2016, that have materially affected or that are reasonably likely to materially affect our internal control over financial reporting.

Management’s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting for us. Our internal control system was designed to provide reasonable assurance regarding the preparation and fair presentation of our published financial statements.

There are inherent limitations to the effectiveness of any control system, however well designed, including the possibility of human error and the possible circumvention or overriding of controls. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Management must make judgments with respect to the relative cost and expected benefits of any specific control measure. The design of a control system also is based in part upon assumptions and judgments made by management about the likelihood of future events, and there can be no assurance that a control will be effective under all potential future conditions. As a result, even an effective system of internal control over financial reporting can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2016. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control – Integrated Framework (2013). Based on this assessment, our management believes that, as of December 31, 2016, our internal control over financial reporting was effective. Deloitte & Touche LLP, the independent registered public accounting firm that audited our financial statements included in Item 8 of this Report, has issued a report on our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Boardwalk GP, LLC
and the Partners of Boardwalk Pipeline Partners, LP

We have audited the internal control over financial reporting of Boardwalk Pipeline Partners, LP and subsidiaries (the “Partnership”) as of December 31, 2016, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership’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 Partnership'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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, Boardwalk Pipeline Partners, LP and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2016, of the Partnership and our report dated February 15, 2017 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP
Houston, Texas

February 15, 2017

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Management of Boardwalk Pipeline Partners, LP

Boardwalk GP manages our operations and activities on our behalf. The operations of Boardwalk GP are managed by its general partner, Boardwalk GP, LLC (BGL). We sometimes refer to Boardwalk GP and BGL collectively as “our general partner.” Our general partner is not elected by unitholders and is not subject to re-election on a regular basis in the future. Unitholders are not entitled to elect the directors of our general partner or directly or indirectly participate in our management or operation. Our general partner owes a fiduciary duty to our unitholders. Our general partner is liable, as general partner, for all of our debts (to the extent not paid from our assets), except for indebtedness or other obligations that are made specifically nonrecourse to it. Whenever possible, our general partner intends that indebtedness or other obligations we incur are nonrecourse to it.

Whenever our general partner makes a determination or takes or declines to take an action in its individual, rather than representative, capacity, it is entitled to make such determination or to take or decline to take such other action free of any fiduciary duty or obligation to any limited partner and is not required to act in good faith or pursuant to any other standard imposed by our partnership agreement or under any law. Examples include the exercise of its limited call rights on our units, as provided in our partnership agreement, its voting rights with respect to the units it owns, its registration rights and its determination whether or not to consent to any merger or consolidation of the Partnership, all of which are described in our partnership agreement. Actions of our general partner made in its individual capacity will be made by BPHC, the sole member of BGL, rather than by our Board.

BGL has a board of directors that oversees our management, operations and activities. We refer to the board of directors of BGL, the members of which are appointed by BPHC, as our Board. BPHC does not apply a formal diversity policy or set of guidelines in selecting and appointing directors that comprise the Board. However, when appointing new directors, BPHC does consider each individual director’s qualifications, skills, business experience and capacity to serve as a director, as described below for each director, and the diversity of these attributes for the Board as a whole.

Directors and Executive Officers

The following table shows information for the directors and executive officers of BGL:

Name	Age	Position
Stanley C. Horton	67	Chief Executive Officer (CEO), President and Director
Jamie L. Buskill	52	Senior Vice President, Chief Financial and Administrative Officer and Treasurer
Michael E. McMahon	61	Senior Vice President, General Counsel and Secretary
Jonathan E. Nathanson	55	Senior Vice President, Corporate Development
Kenneth I. Siegel	59	Director, Chairman of the Board
Arthur L. Rebell	76	Director
William R. Cordes	68	Director
Thomas E. Hyland	71	Director
Mark L. Shapiro	72	Director
Andrew H. Tisch	67	Director
Peter W. Keegan	72	Director

All directors have served since prior to 2010 except for Messrs. Keegan and Horton who were elected to the Board in 2015 and 2011, respectively. All directors serve until replaced or upon their voluntary resignation.

Stanley C. Horton—Mr. Horton has been the President and CEO of BGL since May 2011. Prior thereto he was an independent energy consultant providing consulting services to clients in both Europe and the U.S. From 2005 to 2008, Mr. Horton served as President and Chief Operating Officer of Cheniere Energy, Inc. From 2003 to 2005, he served as President and Chief Operating Officer of subsidiaries of Southern Union, including Panhandle Energy and CrossCountry Energy Services LLC. From 2001 to 2003, Mr. Horton served as Chairman and CEO of Enron Global Services. He has chaired the Gas Industry Standards Board, the Interstate Natural Gas Association of America (INGAA) and the Natural Gas Council. Mr. Horton also served on the Board of Directors for SemGroup Corporation from November 2009 until his resignation effective May 2, 2011. Mr. Horton was selected to serve as a director due to his extensive experience in the natural gas industry and his position with the Registrant. He brings substantial operational experience gained from his executive-level leadership history and the perspective of a former CEO.

Jamie L. Buskill—Mr. Buskill was named Senior Vice President, Chief Financial and Administrative Officer and Treasurer of BGL during 2012. Previously he had been the Senior Vice President, Chief Financial Officer (CFO) and Treasurer of BGL since its inception in 2005 and served in the same capacity for the predecessor of BGL since May 2003. He has served in various management roles for Texas Gas since 1986. Mr. Buskill also serves on the board of various charitable organizations.

Michael E. McMahon—Mr. McMahon has been the Senior Vice President, General Counsel and Secretary of BGL since February 2007. Prior thereto he served as Senior Vice President and General Counsel of Gulf South since 2001. Mr. McMahon has been employed by Gulf South or its predecessors since 1989. Mr. McMahon also serves on the legal committee and the board of directors of the INGAA.

Jonathan E. Nathanson—Mr. Nathanson became Senior Vice President of Corporate Development of BGL in February 2011. Prior to his employment at Boardwalk, Mr. Nathanson served as Vice President of Corporate Development for Loews from 2001 through February 2011 and was a director of BGL from 2005 until he joined BGL in February 2011. Mr. Nathanson began his career as an investment banker in 1989 with a predecessor of Citigroup Inc. Mr. Nathanson has notified the Partnership of his intent to retire effective March 31, 2017.

Kenneth I. Siegel—Mr. Siegel has been employed as a Senior Vice President of Loews since June 2009. From 2008 to 2009 he was employed as a senior investment banker at Barclay’s Capital and from September 2000 to 2008 he was employed in a similar capacity at Lehman Brothers. Mr. Siegel was selected to serve as a director on our Board due to his valuable financial expertise, including extensive experience with capital markets transactions, knowledge of the energy industry and his familiarity with the Partnership due to his role in providing investment banking advice to the Partnership during his prior employment at Barclay’s Capital and Lehman Brothers.

Arthur L. Rebell—Mr. Rebell was a Senior Vice President of Loews from 1998 until his retirement in June 2010. Mr. Rebell was selected to serve as a director on our Board due to his judgment in assessing business strategies taking into account any accompanying risks, his knowledge of finance, mergers and acquisitions and the energy industry and his familiarity with the Partnership due to his role as a member of the Loews team responsible for the acquisitions of Gulf South and Texas Gas and the formation of the Partnership.

William R. Cordes—Mr. Cordes retired as President of Northern Border Pipeline Company in April 2007 after serving as President from October 2000 to April 2007. He also served as CEO of Northern Border Partners, LP from October 2000 to April 2006. Prior to that, he served as President of Northern Natural Gas Company from 1993 to 2000 and President of Transwestern Pipeline Company from 1996 to 2000. Mr. Cordes has more than 35 years of experience working in the natural gas industry. Mr. Cordes is also a member of the board of Kayne Anderson Energy Development Company and Kayne Anderson Midstream Energy Fund, Inc. Mr. Cordes brings to the Board significant pipeline industry experience as well as his extensive business and management expertise from his background as CEO and president of several public companies.

Thomas E. Hyland—Mr. Hyland was a partner in the global accounting firm of PricewaterhouseCoopers, LLP from 1980 until his retirement in July 2005. Mr. Hyland was selected to serve as a director on our Board due to his extensive background in public accounting and auditing, which also qualifies him as an “audit committee financial expert” under SEC guidelines.

Mark L. Shapiro—Mr. Shapiro has been a private investor since 1998. From July 1997 through August 1998, Mr. Shapiro was a Senior Consultant to the Export-Import Bank of the U.S. Prior to that position, he was a Managing Director in the investment banking firm of Schroder & Co. Inc. Mr. Shapiro also serves as a director for W.R. Berkley Corporation. Mr. Shapiro was selected to serve as a director on our Board due to his extensive knowledge and experience in corporate finance, acquisitions and financial matters from his career in investment banking.

Andrew H. Tisch—Mr. Tisch has been Co-Chairman of the Board of Directors of Loews since January 2006. He is also Chairman of the Executive Committee and a member of the Office of the President of Loews and has been a director of Loews since 1985. Mr. Tisch also serves as a director of CNA Financial Corporation, a subsidiary of Loews, and is Chairman of the Board of K12 Inc. Mr. Tisch's qualifications to sit on our Board include his extensive experience on the board of our parent company, his extensive leadership skills and keen business and financial judgment, as well as his role in forming the Partnership.

Peter W. Keegan—Mr. Keegan was Senior Vice President and CFO of Loews from 1997 until his retirement in May 2014 and is currently Senior Advisor to Loews. Prior to joining Loews, Mr. Keegan served as Executive Vice President and CFO of CBS

Inc. Mr. Keegan was selected to serve as a director on our Board due to his familiarity with the Partnership, his experience as a senior leader at large public companies and his knowledge of finance and accounting matters.

Our Independent Directors

Our Board has determined that Thomas E. Hyland, Mark L. Shapiro, Arthur L. Rebell and William R. Cordes are independent directors under the listing standards of the NYSE. Our Board considered all relevant facts and circumstances and applied the independence guidelines described below in determining that none of these directors has any material relationship with us, our management, our general partner or its affiliates or our subsidiaries.

Our Board has established guidelines to assist it in determining director independence. Under these guidelines, a director would not be considered independent if any of the following relationships exists:

(i) during the past three years the director has been an employee, or an immediate family member has been an executive officer, of us;

(ii) the director or an immediate family member received, during any twelve month period within the past three years, more than $120,000 per year in direct compensation from us, excluding director and committee fees, pension payments and certain forms of deferred compensation;

(iii) the director is a current partner or employee or an immediate family member is a current partner of a firm that is our internal or external auditor, or an immediate family member is a current employee of such a firm and personally works on our audit, or, within the last three years, the director or an immediate family member was a partner employee of such a firm and personally worked on our audit within that time;

(iv) the director or an immediate family member has at any time during the past three years been employed as an executive officer of another company where any of our present executive officers at the same time serves or served on that company’s compensation committee; or

(v) the director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, us for property or services in an amount which, in any of the last three years, exceeds the greater of $1.0 million, or 2% of the other company’s consolidated gross revenues.

Our Board is comprised of a majority of independent directors and our Audit Committee is comprised solely of independent directors. The NYSE does not require a listed limited partnership, or a listed company that is majority-owned by another listed company, such as us, to maintain a compensation or nominating/corporate governance committee. In reliance on this exemption, we do not maintain a compensation or nominating/corporate governance committee.

Audit Committee

We have established a separately-designated standing audit committee in accordance with SEC rules. Our Board’s Audit Committee presently consists of Thomas E. Hyland, Chairman, Mark L. Shapiro and William R. Cordes, each of whom is an independent director and satisfies the additional independence and other requirements for Audit Committee members provided for in the listing standards of the NYSE. The Board of Directors has determined that Mr. Hyland qualifies as an “audit committee financial expert” under SEC rules.

The primary function of the Audit Committee is to assist our Board in fulfilling its responsibility to oversee management’s conduct of our financial reporting process, including review of our financial reports and other financial information, our system of internal accounting controls, our compliance with legal and regulatory requirements, the qualifications and independence of our independent registered public accounting firm (independent auditors) and the performance of our internal audit function and independent auditors. The Audit Committee has sole authority to appoint, retain, compensate, evaluate and terminate our independent auditors and to approve all engagement fees and terms for our independent auditors.

Conflicts Committee

Under our partnership agreement, our Board must have a Conflicts Committee consisting of two or more independent directors. Our Conflicts Committee presently consists of Mark L. Shapiro, Chairman, Thomas E. Hyland and William R. Cordes. The primary function of the Conflicts Committee is to determine if the resolution of any conflict of interest with our general partner or its affiliates is fair and reasonable. Any matters approved by the Conflicts Committee will be conclusively deemed to be fair and reasonable, approved by all of the partners and not a breach by our general partner of any duties it may owe to our unitholders.

Executive Sessions of Non-Management Directors

Our Board's non-management directors, from time to time as such directors deem necessary or appropriate, meet in executive sessions without management participation, with the Chairman of the Board presiding over these meetings. Unless otherwise designated by the Chairman of the Board, the Chairman of the Audit Committee or the Chairman of the Conflicts Committee would serve as the presiding director at these meetings if the Chairman of the Board was not participating.

Governance Structure and Risk Management

Our principal executive officer and Board chairman positions are held by separate individuals. We have taken this position to achieve an appropriate balance with regard to oversight of company and unitholder interests, Board member independence, power and guidance for the principal executive officer regarding business strategy, opportunities and risks.

Our Board is engaged in the oversight of risk through regular updates from Mr. Horton, in his role as our CEO, and other members of our management team, regarding those risks confronting us, the actions and strategies necessary to mitigate those risks and the status and effectiveness of those actions and strategies. The updates are provided at quarterly Board and Audit Committee meetings as well as through more frequent meetings that include the Board Chairman, other members of our Board, the CEO and members of our management team. The Board provides insight into the issues, based on the experience of its members, and provides constructive challenges to management's assumptions and assertions.

Corporate Governance Guidelines and Code of Business Conduct and Ethics

Our Board has adopted Corporate Governance Guidelines to guide it in its operation and a Code of Business Conduct and Ethics applicable to all of the officers and directors of BGL, including the principal executive officer, principal financial officer, principal accounting officer, and all of the directors, officers and employees of our subsidiaries. The Corporate Governance Guidelines and Code of Business Conduct and Ethics can be found within the "Governance" section of our website, located at www.bwpmlp.com. We intend to post changes to or waivers of this Code for BGL's principal executive officer, principal financial officer and principal accounting officer on our website.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Exchange Act requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file initial reports of ownership and reports of changes in ownership with the SEC. Such persons are required by SEC regulation to furnish us with copies of all Section 16(a) forms they file. Based solely on our review of the copies of such forms furnished to us and written representations from our executive officers and directors, we believe that all Section 16(a) filing requirements were met during 2016, in a timely manner.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Executive Summary

The objective of our executive compensation program is to attract and retain highly qualified executive officers and motivate them to provide a high level of performance for our Partnership. To meet this objective, we have established a compensation policy for our executive officers which offers elements of base salary, cash incentives, equity-based incentives and retirement and other benefits. Our strategy is to combine these elements at levels that provide our Named Executive Officers (as identified below) compensation that is competitive with that offered at similar companies in the energy industry, with particular emphasis on retention and rewarding performance by offering short and long-term incentive-based compensation. As determined annually by our Board of Directors (Board), the Named Executive Officers that are discussed within this section for 2016 include Mr. Stanley C. Horton, our President, Chief Executive Officer (CEO) and a director of BGL (principal executive officer), Mr. Jamie L. Buskill, our Senior Vice President, Chief Financial and Administrative Officer and Treasurer (CFO) (principal financial officer), and our two other executive officers, Mr. Michael E. McMahon, Senior Vice President, General Counsel and Secretary and Mr. Jonathan E. Nathanson, Senior Vice President, Corporate Development. Effective February 2, 2017, Mr. John L. Haynes, Senior Vice President, Chief Commercial Officer and President, Boardwalk Field Services, LLC, was appointed a Named Executive Officer by our Board.

We consider a number of factors in making our determinations of executive compensation, including compensation paid in prior years, whether the Partnership's financial, operating and growth objectives were achieved and the individual contributions of each executive officer to our overall business success for the year. As described below, we have periodically used, and may use in the future, executive compensation surveys as general guidelines for setting total executive compensation, but we do not benchmark our compensation to any particular group of companies.

In the development of our executive compensation programs, we have considered the compensation programs of various companies engaged in similar businesses with similar corporate structures to obtain a general understanding of compensation practices and industry trends. We have also considered the historical compensation policies and practices of our operating subsidiaries and, as discussed below under Risk Assessment, whether our compensation policies and practices could possibly introduce material risks to our business. In addition, in light of our structure as a publicly traded partnership, we have considered the applicable tax and accounting impacts of executive compensation, including the tax implications of providing equity-based compensation to our employees, all of whom are employed by our operating subsidiaries.

As discussed above, our compensation policy includes offering cash incentives to reward for performance. Annual bonus awards are a component of that policy. The annual bonus awards for 2016 were determined after we reviewed both the performance of our Partnership and the individual performance of each of the Named Executive Officers. With respect to Partnership performance, our 2016 results which significantly impacted the Board’s compensation decisions, included the following:

- we had no material safety or pipeline deliverability issues and we were in compliance with all federal, state and local laws, rules and regulations;
- we exceeded EBITDA and distributable cash flow amounts included in our plan;
- we continued to take steps to enhance the Partnership’s financing options, including refinancing expiring, fixed-rate notes, extending the term of our Revolving Credit Agreement, extending the borrowing period under our Subordinated Loan Agreement with our general partner and executing a new $500.0 million equity distribution agreement;
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- we placed into service four major growth projects on time and under budget and were successful in executing additional contracts that support new growth projects;
- our organic growth projects identified in Part I, Item 1 Business-Current Growth Projects of this Report are progressing as contemplated and remain on target and on budget; and
- we continued to work on strengthening our balance sheet by funding growth projects with internally generated cash flows, and we completed 2016 with a debt to EBITDA ratio of approximately 4.5x and obtained investment grade debt ratings by the three major rating agencies.

Based on these results and the leadership, performance and efforts of each of the Named Executive Officers toward the achievement of these results, the Board awarded to the Named Executive Officers individual annual cash bonus amounts that, on a combined basis, were higher than the target amounts set for 2016.

As discussed elsewhere in this Report, our Board does not have a Compensation Committee. Therefore, the compensation for our Named Executive Officers, is reviewed with and is subject to the approval of our entire Board, with Mr. Horton not participating in those Board discussions with respect to his own compensation.

Compensation Philosophy

Our compensation philosophy is to reward our Named Executive Officers for achieving Partnership and individual performance objectives, align the interests of the Named Executive Officers with the interests of the Partnership and unitholders and provide competitive pay to attract and retain top talent.

Compensation Program Objectives

The objectives of our compensation program are to:

- Attract, motivate and retain highly qualified Named Executive Officers with market-competitive compensation;
- Create a strong link between pay and performance (both Partnership and individual performance);
- Motivate the Named Executive Officers to achieve both short and long-term Partnership goals;
- Align interests of Named Executive Officers with the interests of the Partnership; and
- Encourage prudent business behavior and minimize inappropriate risk taking.

Compensation Program Elements

The following are the principal components of compensation for each of our Named Executive Officers:

Compensation Element	Objectives	Design Elements
Base Salary	* Attract and retain executives by providing compensation comparable with similar positions in the industry.	* Base salary levels are reviewed annually and may be adjusted based both on individual performance and market competitiveness of total direct compensation (which is the sum of base salary, short-term incentive awards and long-term incentive awards).
Short-Term Incentive Award	* Drive annual business performance by rewarding achievement of Partnership objectives.	* Awards are comprised of annual cash bonus awards (STI Awards) under our Short-Term Incentive Plan (STIP).
	* Drive individual performance by including an individual performance component.	* Payout of awards can range from 0% to 200% of target, at the discretion of the Board, based both on Partnership and individual performance, with equal weighting on both.
	* Attract talent by providing competitive short-term cash incentive targets.	* Target levels are reviewed annually and may be adjusted based on market competitiveness of total direct compensation.
	* Reinforce corporate values of safety and compliance as Partnership objectives.	
Long-Term Incentive Award	* Attract and retain talent, motivate top performance and provide opportunity to share in long-term success of the Partnership.	* Awards can consist of a combination of or any one of the following: phantom common units (Phantom Common Units) under our Long-Term Incentive Plan (LTIP) and long-term cash bonuses (Long-Term Cash Bonus) under our Unit Appreciation Rights and Cash Bonus Plan (UAR and Cash Bonus Plan).
	* Minimize inappropriate risk-taking by providing the appropriate mix of award types.	* Longer vesting periods achieve retention objectives and discourage unreasonable risk taking for short-term gain.
	* Drive long-term business performance by aligning reward with common unit price, appreciation in common unit price and distributions to unitholders.	* Phantom Common Units encourage retention and facilitate alignment with unitholder interests.
	* Drive individual performance by setting grant levels based on individual performance.	* Long-Term Cash Bonus awards support retention of executives and provide our Board flexibility to mix equity-based and non-equity-based long-term compensation to support its objectives.
		* Mix of award types is reviewed annually.
		* Award levels are reviewed annually and are based on individual performance and market competitiveness of total direct compensation.
Benefits	* Attract and retain executives by providing market competitive benefits.	* Reviewed annually to ensure competitiveness.

Market Analysis

When determining the appropriate amounts of individual compensation components, the Board considers a number of factors, including the individual officer's skills, experience and responsibilities, the amounts of current and prior compensation as well as the appropriate amounts necessary to further our retention efforts. We do not determine compensation by benchmarking, or targeting our compensation to fall within a specific percentile of compensation as reported in compensation surveys. However, as described above, a key objective of our Compensation program is to maintain market competitiveness in order to attract and retain executives with the ability and experience necessary to provide leadership and strong performance for the Partnership. Therefore, from time to time, we may review market compensation data to assess the reasonableness of our compensation practices.

With respect to our 2016 compensation decisions, we used the 2016 Towers Watson U.S. Compensation Data Bank Energy Services Executive Compensation Survey (Towers Watson) and the 2016 US Mercer Total Compensation Survey for the Energy Sector (Mercer) to conduct a market-based review of total direct compensation, which we define as the sum of base salary, short-term incentives and long-term incentives. The compensation survey data we reviewed was a compilation of approximately 480 companies that are engaged in various segments of the energy industry. In 2016, we also conducted an informal survey of certain of our peers for certain positions based on publicly available data as discussed below.

Our general objective was to assess each officer’s total direct compensation for reasonableness in relation to the median amount for similarly situated officers. We did not set specific target percentiles for either total direct compensation or the individual compensation components, and we determined a median market total direct compensation amount for each officer position.

When making compensation decisions, the Board considers all information available, including the factors listed above, with the final amounts of compensation to be ultimately determined at the discretion of the Board. This process allows us to achieve our primary objective of maintaining competitive compensation to ensure retention and rewarding the achievement of the Partnership's objectives to align with the interests of unitholders.

The following discussion addresses each of the individual components of compensation for our Named Executive Officers.

Compensation Attributable to the 2016 Calendar Year

The Board approved short-term and long-term incentive awards in 2017, which it considers to be related to 2016, even though the long-term incentive awards will not be reported in the Summary Compensation Table until 2017 or later, depending on the type of award. We consider compensation attributable to the 2016 calendar year to include the base salary paid during 2016, STI Awards awarded and paid in early 2017, but related to results achieved in 2016, and Long-Term Incentive Awards granted in early February 2017, but related to the results achieved in 2016. The table below summarizes the compensation for our Named Executive Officers that we consider to be related to the 2016 calendar year. In considering compensation amounts for Mr. Nathanson, the Board took into account his intent to retire effective March 31, 2017. The terms of the long-term incentive awards require that in order for a Named Executive Officer to become vested in the award upon retirement, the retirement must occur the longer of 13 months after the grant date or one year after a retirement notice is provided, otherwise the award will be forfeited. Since Mr. Nathanson’s long-term incentive awards would be forfeited upon his retirement because he did not meet the time requirement, he was not awarded long-term incentive awards in 2017. The amounts reported below differ from those reported in the Summary Compensation Table due solely to the disclosure rules regarding the timing of reporting certain elements of compensation.

Name	2016 Base Salary (1)	STI Bonus Paid in 2017 for the 2016 Calendar Year	Long-Term Cash Bonus Granted in 2017 for the 2016 Calendar Year (2)	Grant Date Fair Value for Long-Term Incentive Plan Awards granted in 2017 for the 2016 Calendar Year (3)	Total
Stanley C. Horton	$850,018	$1,162,000	$506,250	$1,656,017	$4,174,285
Jamie L. Buskill	$408,661	$500,000	$150,000	$490,661	$1,549,322
	$307,624	$420,000	$137,500	$449,785	$1,314,909

Michael E. McMahon					
Jonathan E. Nathanson	$333,470	$385,000	$—	$—	$718,470

(1) Represents the base salary for Mr. Horton for the entire year. Messrs. Buskill, McMahon and Nathanson’s base salaries were each increased by approximately 3% effective February 22, 2016. In addition, Mr. Buskill’s base salary was increased to $450,000 from his previous salary of $335,000 effective May 2, 2016. Refer to Base Salary below for further discussion of base salary adjustments.

(2) Represents Long-Term Cash Bonuses granted under our UAR and Cash Bonus Plan on February 2, 2017.

(3) Represents the grant date fair value of the Phantom Common Units granted under our LTIP on February 2, 2017. Messrs. Horton, Buskill and McMahon were granted 89,129, 26,408 and 24,208 units. The fair value of each unit was derived based on the closing price of $18.58 for the Partnership's common units on the NYSE on February 1, 2017. Refer to Long-Term Incentive Awards – Phantom Common Units for further discussion regarding the Phantom Common Units.

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For compensation attributable to the 2016 calendar year, approximately 76% of the total direct compensation awarded to our Named Executive Officers was based on incentive-based compensation elements, the majority of which was comprised of long-term, incentive-based compensation.

Base Salary

We provide our Named Executive Officers with an annual base salary to compensate them for services rendered during the year. Our goal is to set base salaries for our Named Executive Officers at levels that make total direct compensation competitive with comparable companies for the skills, experience and requirements of similar positions in order to attract and retain top talent. In each year, the market competitiveness of the total direct compensation for Messrs. Horton, Buskill, McMahon and Nathanson is reviewed. Consistent with the average base salary merit increase for all other employees, Messrs. Buskill, McMahon and Nathanson each received an approximate 3% increase in their base salaries effective February 22, 2016. After comparing Mr. Buskill's total direct compensation to executive compensation data available in the Towers Watson and Mercer compensation surveys and publicly available executive compensation information with regard to some of Mr. Buskill's peers, his base salary was increased to $450,000 from his previous salary of $335,000 effective May 2, 2016, in order to better align his total direct compensation with that of his peers and with the market data. Prior to the adjustments discussed herein, Messrs. Buskill and Nathanson had not had a base salary increase since 2011 and Mr. McMahon had not had a base salary increase since 2013.

In 2015, Mr. Horton's base salary was increased from $600,000 to $850,000. Mr. Horton has been instrumental in setting the strategic direction for the organization and providing leadership for the senior management team and employee group who, under challenging market conditions, have accomplished the results noted herein. Mr. Horton had not had a base salary increase since he was hired in 2011. No changes were made to the base salary of Mr. Horton in 2016.

Incentive Compensation

The Board considers incentive compensation awards paid or granted in early 2017 to be related to 2016 performance even though the awards will not be reported in the Summary Compensation Table and other compensation tables until 2017 or later, depending on the type of award. Our incentive compensation program is comprised of several components:

- annual cash bonus awards under our STIP;
- long-term, equity-based awards under our LTIP; and
- Long-Term Cash Bonuses under our UAR and Cash Bonus Plan.

Our goal is to set incentive target awards at levels that make total direct compensation competitive with comparable companies for the skills, experience and requirements of similar positions in order to attract and retain top talent. The incentive target awards can differ from actual awards as a result of Partnership and/or individual performance, but the actual payout of any award is determined at the sole discretion of the Board.

In determining the amount of any incentive awards, the Board considers factors that include its view of our financial and operational performance for the most recently completed fiscal year, the performance of the individual, the responsibilities of the individual's position and the individual's contribution to our Partnership. The Board also gives consideration to external factors and market conditions experienced by the Partnership impacting its business. Except with regard to STI Awards made under the STIP, there is no specific weight assigned to any factor. Instead, the Board considers and balances the various performance objectives as it deems appropriate.

STI Awards. An STI Award is an annual cash bonus award under our STIP, the payout of which is based on the Board's subjective analysis of the Partnership's performance and the performance of our Named Executive Officers during the year. At the beginning of the year, each Named Executive Officer is assigned a target amount, which is established as a percentage of the officer's base salary. The plan provides that payouts under the STIP can range from zero to 200% of the target amount, with 50% of the payout determined after taking into account our Partnership's performance and 50% based on individual performance. The target and maximum potential payouts under the STIP as well as the allocation between Partnership and individual performance were determined at the discretion of the Board. In determining the target amount of the STI Awards, the Board considered (i) the value of each officer's prior STI Awards, and (ii) the potential value of the STI Awards on the total direct compensation for each officer. The following are the target potential payout amounts that were established for 2016 for our Named Executive Officers:

Name	2016 Base Salary (1)	2016 STI Target %	2016 STI Target Payout
Stanley C. Horton	$850,018	100%	$850,018
Jamie L. Buskill	$408,661	100%	$408,661
Michael E. McMahon	$307,624	100%	$307,624
Jonathan E. Nathanson	$333,470	100%	$333,470

(1) Represents the base salary paid for 2016.

When determining whether to pay an STI Award for the year, the Board considers recommendations made by the CEO which are based on his subjective evaluation of whether, and to what extent, our Partnership met its performance goals during the year. He also makes recommendations based on his subjective assessment of the individual performance of each of the other Named Executive Officers. Any STI Award paid to the CEO is determined by the Board based upon a similar review performed by the Board without input from the CEO.

Our partnership performance goals are based on objectives that we believe reflect a well-rounded view of our performance. However, these goals are not tied to any specific targets and our achievement of these goals is ultimately determined by the Board in its sole discretion. For 2016, the following general objectives, which we refer to as Partnership Performance Goals, were established by the CEO and approved by the Board:

1. Operate our assets safely, reliably and in compliance with all applicable federal and state laws and governmental rules and regulations.
2. Focus on delivering financial results that are consistent with the Partnership's 2016 budget.
3. Explore strategic acquisition opportunities that would support profitable diversification and/or growth of our business.
4. Improve efficiency throughout the Partnership including operating within departmental budgets.
5. Market firm transportation, storage, gathering and processing services.
6. Complete all projects on-time and meet project schedules for the year.
7. Remain within budgeted capital expenditures while meeting strict safety and compliance guidelines and business needs.
8. Identify other new growth and/or efficiency projects during the year that will result in the Partnership meeting its long-term growth projections and financial performance.

As discussed under Executive Summary, in light of the Partnership's achievements in 2016, the Board determined that we met a significant portion of our Partnership Performance Goals, which resulted in the determination that approximately 98.5% of the partnership performance portion of each STI Award should be paid.

The Board also subjectively considered the contributions of our Named Executive Officers, including the individual leadership, performance and efforts of each officer with respect to the Partnership's achievement of these goals. The following is a discussion of the material factors that were considered by the Board in determining what percentage of the annual incentive award would be paid based on individual performance:

Stanley C. Horton: In assessing Mr. Horton's individual performance, the Board considered the accomplishments and the performance of the Partnership, as well as the leadership and strategic direction that Mr. Horton provided the entire employee team, including senior management, in terms of executing strategies to achieve the Partnership's goals with respect to the market conditions impacting the midstream sector of the energy business. The Board also considered his customer relationships, past experience and vast knowledge of the industry which are of major importance to the Partnership.

Jamie L. Buskill: In assessing Mr. Buskill's performance, the Board considered the accomplishments of the Partnership and Mr. Buskill's continued leadership of the finance and accounting organization, which provides reporting to regulatory agencies and communication to the financial community and rating agencies, ensures proper capitalization of the Partnership for both the near-term and long-term under reasonable terms and conditions, provides fiduciary oversight by ensuring effective controls, procedures and risk management practices are in place and ensures the Partnership has sufficient liquidity for executing the Partnership's operating plans and strategies. As Chief Administrative Officer, Mr. Buskill had oversight over information technology, human resource practices, and other administrative functions of the Partnership. The Board also considered his knowledge of and the relationships within the industry and financial markets, which is of major importance to the Partnership, and his success in ensuring that adequate financing tools are in place to be able to fund the Partnership's growth projects under development.

Michael E. McMahon: In assessing Mr. McMahon's performance, the Board considered the accomplishments of the Partnership and Mr. McMahon's leadership of the legal and regulatory organizations, including his oversight in the Partnership's compliance with applicable state and federal laws. Mr. McMahon provided oversight of FERC matters, including the recently settled Gulf South rate case, and other tariff filings and certificate applications required to support the Partnership's growth projects. He also represented the Partnership with regard to state and federal governmental affairs and within various industry associations, including serving on the board of directors of the Interstate Natural Gas Association of America. The Board also considered his knowledge of the industry, and regulatory and legal matters which supports the Partnership's success.

Jonathan E. Nathanson: In assessing Mr. Nathanson's performance, the Board considered the accomplishments of the Partnership and Mr. Nathanson's analysis of various acquisition opportunities and his leadership of the corporate development organization which is responsible for analyzing economics for all major growth projects, including the projects identified in Part I, Item 1 Business - Current Growth Projects of this Report. The Board also considered his knowledge of the industry and financial markets which is of major importance to the Partnership.

In light of these considerations, the Board approved the following payout of STI Awards for each Named Executive Officer:

Name	2016 Incentive Payout as % of Base Salary	STI Bonus
Stanley C. Horton	137%	$1,162,000
Jamie L. Buskill	122%	$500,000
Michael E. McMahon	137%	$420,000
Jonathan E. Nathanson	115%	$385,000

Each of the STI awards above was determined as follows: 50% of the award was based on Partnership performance of approximately 98.5% of target and 50% of the award was based on individual performance, as determined at the discretion of the Board.

Long-Term Incentive Awards – Phantom Common Units and Long-Term Cash Bonuses. We may grant a combination of cash and equity-based compensation awards, or any one of these awards individually, to our Named Executive

Officers under our LTIP and our UAR and Cash Bonus Plan on an annual basis. The equity-based compensation awards are settled in cash rather than in the form of actual common units due to our structure as a limited partnership and certain tax matters associated with employee benefit plans. We currently limit the type of equity-based awards that we grant to Phantom Common Units under our LTIP, which are settled in cash. For the amounts of long-term incentive awards granted to our Named Executive Officers related to 2016, refer to the Compensation Attributable to the 2016 Calendar Year table.

The Board reviews and approves the mix of the awards annually, which supports the Compensation Program Objectives stated previously. Our long-term awards, whether cash or equity-based, typically have longer multiple year vesting periods and help achieve our retention objectives. The long-term incentive awards granted in 2017 and attributed to 2016 were in the form of Long-Term Cash Bonuses and Phantom Common Units, which align the interests of the Named Executive Officers with the value of our common units and allow participation in any appreciation of the value of the common units, while also offering a mixture of different award types. For Messrs. Horton, Buskill and McMahon, approximately 25% of the long-term incentive award was awarded in the form of Long-Term Cash Bonuses and the remaining 75% was in the form of Phantom Common Units. Mr. Nathanson was not awarded long-term incentive compensation in 2017 because of his intent to retire on March 31, 2017.

A Phantom Common Unit converts into the right to receive cash equal to the value of a common unit plus an amount equal to the accumulated amount of cash distributions made with respect to a common unit during the period the Phantom Common Units were outstanding, upon the satisfaction of the time-based criteria specified in the grant. For the Phantom Common Units granted in 2017, half of the awards will vest on December 1, 2018, and the other half will vest on December 1, 2019. With respect to the Phantom Common Units, the grantee must select one of two irrevocable payment elections shortly after the award is granted. If the first payment election is selected, an amount equal to the fair market value of the vested portion of the Phantom Common Units and associated cash distributions are payable to the grantee in cash upon each of the two vesting dates. If the second payment election option is selected, the fair market value for the Phantom Common Units and associated cash distributions, for all awards regardless of vesting date, are determined and paid at the final vesting date. Similar Phantom Common Unit awards were also granted in 2016 and 2015.

We have previously granted UARs to our employees, although no UARs have been granted to our Named Executive Officers since February 2013, and there are no remaining outstanding UARs held by the Named Executive Officers.

We may grant Long-Term Cash Bonuses as part of our incentive program. These awards mainly serve as retention awards, therefore they are not granted each year. We last granted Long-Term Cash Bonuses in early 2014 with respect to the 2013 year. For the Long-Term Cash Bonuses that were granted in 2017 and attributed to 2016, half of the awards will vest on December 1, 2018, and the other half on December 1, 2019, subject to the Named Executive Officer remaining continuously employed until that date, except for instances of retirement. The Named Executive Officer will become fully vested in the Long-Term Cash Bonus award upon retirement if retirement occurs 13 months after the grant date or one year after a retirement notice is provided, whichever is longer. At the end of the vesting period, our Named Executive Officers that continue to be employees are entitled to receive cash in the amount of the grant, or with respect to meeting the time requirements for retirement, are entitled to receive cash in the amount of the grant within 30 days of the initial vesting date.

In determining the size of the annual long-term incentive awards granted to our Named Executive Officers and in assessing the reasonableness of those awards, the Board considered the value of each officer's prior long-term incentive awards, as well as the impact of the value of long-term incentive awards on total direct compensation.

Employee Benefits

Each Named Executive Officer participates in benefit programs available generally to salaried employees of the operating subsidiary which employs such officer, including health and welfare benefits and a qualified defined contribution 401(k) plan that includes a dollar-for-dollar match on elective deferrals of up to 6% of eligible compensation within Internal Revenue Code (IRC) requirements. With the exception of Mr. Buskill, our Named Executive Officers participate in a defined contribution money purchase plan, which is available to employees of Gulf South and employees of Texas Gas hired on or after November 1, 2006. Our contributions to these defined contribution plans on behalf of the participating Named Executive Officers are reported in the Summary Compensation Table.

Mr. Buskill participates in a defined benefit cash balance pension plan available to employees of Texas Gas hired prior to November 1, 2006, and includes a non-qualified restoration plan for amounts earned in excess of IRC limits for qualified retirement plans. Mr. Buskill is also eligible for retiree medical benefits after reaching age 55 as part of a plan offered to Texas Gas employees hired prior to January 1, 1996. For more details regarding the pension benefits provided to Mr. Buskill, see Pension Benefits below.

All Other Compensation

There were no material perquisites or personal benefits paid to our Named Executive Officers in 2016.

Equity Ownership Guidelines

As discussed above, our executives would suffer significant negative tax consequences by owning our common units directly. As a result, we do not have a policy or any guidelines regarding required equity ownership by our management. We therefore seek to align the interests of management with our unitholders by periodically granting Phantom Common Units and UARs.

Clawbacks

The Long-Term Cash Bonus awards granted in 2017 and the Phantom Common Unit awards granted in 2017, 2016 and 2015 contain a clawback provision that states that, in the event that an applicable law is violated, including the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, any Securities and Exchange Commission (SEC) rule or any applicable securities exchange listing standards, or any Partnership policy, all awards will be subject to forfeiture or recoupment to the extent necessary to comply with such laws or policy.

Risk Assessment

We have reviewed our compensation policies and practices for all employees, including Named Executive Officers, and determined that our compensation programs are not reasonably likely to cause behaviors that would have a material adverse effect on the Partnership. In arriving at this determination, the Board considered potential risks when reviewing and approving both executive-level and broad-based compensation programs. We have designed our compensation programs, including our incentive compensation plans, to minimize potential risks while rewarding employees for achieving long-term financial and strategic objectives through prudent business judgment. In particular, our compensation programs were designed to provide a balanced mix of cash and equity-based, annual and longer-term incentives, which are discretionary and subject to the Board’s evaluation of Partnership performance metrics as well as individual contributions to the Partnership's performance. Further, awards of incentive compensation are not purely formula driven, and the Board retains full discretion with regard to increasing or decreasing total compensation or any element of total compensation.

Board of Directors Report on Executive Compensation

In fulfilling its responsibilities, our Board has reviewed and discussed the Compensation Discussion and Analysis with our management. Based on this review and discussion, the Board recommended that the Compensation Discussion and Analysis be included in this Report.

By the members of the Board of Directors:

William R. Cordes
Stanley C. Horton
Thomas E. Hyland
Peter W. Keegan
Arthur L. Rebell
Mark L. Shapiro
Kenneth I. Siegel, Chairman
Andrew H. Tisch

Compensation Committee Interlocks and Insider Participation

As discussed above, our Board does not maintain a Compensation Committee. Our entire Board performs the functions of such a committee. None of our directors, except Mr. Horton, have been or are officers or employees of us or our subsidiaries. Mr. Horton participates in deliberations of our Board with regard to executive compensation generally, but does not participate in deliberations or Board actions with respect to his own compensation. None of our Named Executive Officers served as a director or member of a compensation committee of another entity that has or has had an executive officer who served as a member of our Board during 2016, 2015 or 2014.

Executive Compensation

Summary of Executive Compensation

The Board approved short and long-term incentive awards in 2017, which it considers to be related to 2016 even though the long-term incentive awards will not be reported in the Summary Compensation Table until 2017 or later, depending on the type of award. We consider compensation attributable to the 2016 calendar year to include the base salary paid during 2016, STI Awards awarded and paid in early 2017, but related to results achieved in 2016, and Long-Term Incentive Awards granted in early February 2017, but related to the results achieved in 2016. Refer to Compensation Attributable to the 2016 Calendar Year for further information. The following table shows a summary of total compensation earned by our Named Executive Officers for 2016, 2015 and 2014, reported in accordance with the SEC rules regarding the timing of executive compensation:

Summary Compensation Table for 2016

Name and Principal Position	Year	Salary ($)	Bonus (1)(2) ($)	Unit Awards (3) ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)		All Other Compensation ($)		Total (9) ($)
Stanley C. Horton, CEO									
	2016	850,018	3,009,500	1,610,290	—		34,142	(4)	5,503,950
	2015	811,554	1,709,500	1,798,834	—		34,142		4,354,030
	2014	600,000	800,000	—	—		30,348		1,430,348
Jamie L. Buskill, CFO									
	2016	408,661	1,221,250	447,307	320,128	(5)	20,179	(6)	2,417,525
	2015	325,000	621,250	499,670	109,125		19,687		1,574,732
	2014	325,000	385,000	—	204,931		19,387		934,318
Michael E. McMahon, Senior Vice President, General Counsel and Secretary									
	2016	307,624	1,060,000	380,209	—		32,988	(7)	1,780,821
	2015	300,000	640,000	399,739	—		32,828		1,372,567
	2014	300,000	360,000	—	—		30,396		690,396
Jonathan E. Nathanson, Senior Vice President, Corporate Development									
	2016	333,470	1,010,000	380,209	—		28,813	(8)	1,752,492
	2015	325,000	610,000	399,739	—		27,709		1,362,448
	2014	325,000	385,000	—	—		27,209		737,209

(1) The amounts shown in this column represent cash STI Awards earned under our STIP for 2016, 2015 and 2014. See the Compensation Discussion and Analysis above for discussion of the 2016 STI Awards. The amounts for 2016 and 2015 also include retention payments described below. In 2014, Long-Term Cash Bonuses were granted to Messrs. Horton, Buskill, McMahon and Nathanson having stated amounts of $1,300,000, $500,000, $400,000 and $400,000. The awards vested and became payable, subject to the terms of the plan and grant agreements, on December 16, 2016, and are reported in the Summary Compensation Table in 2016, or the year they were earned.

(2) In 2014, Messrs. Horton, Buskill, McMahon and Nathanson were awarded $2,190,000, $885,000, $960,000 and $900,000 under Retention Payment Agreements. Each award will vest and become payable as follows: 25% vested and became payable on February 28, 2015, 25% vested and became payable on February 29, 2016, and the remaining 50% will vest and become payable on February 28, 2017. In 2016 and 2015, amounts earned and paid to Messrs. Horton, Buskill, McMahon and Nathanson under the Retention Payment Agreements were $547,500, $221,250, $240,000 and $225,000 for each year.

(3) Messrs. Horton, Buskill, McMahon and Nathanson were granted “Unit Awards” in the form of Phantom Common Units under our LTIP in February 2016 having a grant date fair value, determined in accordance with GAAP, of $1,610,290, $447,307, $380,209 and $380,209 and reported in the Summary Compensation Table for 2016. The fair value of each unit was derived based on the closing price of $10.61 for our common units on the NYSE on February 3, 2016. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); will vest 50% on December 1, 2017, and 50% on December 1, 2018; and will be payable in cash to the grantee pursuant to a payment option selected by the grantee in an amount equal to the 30 day trading average closing price of the units

(as defined in the plan). The vested amount then credited to the grantee's DER account will be payable in cash. Messrs. Horton, Buskill, McMahon and Nathanson were also granted Phantom Common Units under our LTIP in February 2015 having a grant date fair value, determined in accordance with GAAP, of $1,798,834, $499,670, $399,739 and $399,739 and reported in the Summary Compensation Table for 2015. The fair value of each unit was derived based on the closing price of $15.51 for our common units on the NYSE on February 4, 2015. Each such grant includes a tandem grant of DERs; vested 50% on December 1, 2016, and will vest 50% on December 1, 2017; and will be payable in cash to the grantee pursuant to a payment option selected by the grantee in an amount equal to the 30 day trading average closing price of the units (as defined in the plan). The vested amount then credited to the grantee's DER account will be payable in cash. Note 11 in Part II, Item 8 of this Report contains information regarding the grant fair value of the Phantom Common Units. See Compensation Discussion and Analysis for more information regarding the terms of the Long-Term Incentive awards.

(4) Includes matching contributions under 401(k) plan ($15,900), employer contributions to the Boardwalk Savings Plan ($10,600), imputed life insurance premiums ($6,858) and preferred parking.

(5) Includes the change in qualified retirement plan account balance ($60,999) and interest and pay credits for the supplemental retirement plan ($259,129). Details about both pension plans are contained in the Pension Benefits section below.

(6) Includes matching contributions under 401(k) plan ($15,900), imputed life insurance premiums ($3,495) and preferred parking.

(7) Includes matching contributions under 401(k) plan ($15,900), employer contributions to the Boardwalk Savings Plan ($10,600), imputed life insurance premiums ($5,704) and preferred parking.

(8) Includes matching contributions under 401(k) plan ($15,900), employer contributions to the Boardwalk Savings Plan ($10,600) and imputed life insurance premiums ($2,313).

(9) In addition to the compensation reported herein, in 2017, Long-Term Cash Bonuses were granted to Messrs. Horton, Buskill and McMahon having stated amounts of $506,250, $150,000 and $137,500. The awards will vest and become payable 50% on December 1, 2018, and 50% on December 1, 2019. Additionally, Messrs. Horton, Buskill and McMahon were granted "Unit Awards" in the form of Phantom Common Units under our LTIP, having a grant date fair value of $1,656,017, $490,661 and $449,785. The fair value of each unit was derived based on the closing price of February 1, 2017, for our common units on the NYSE of $18.58. Each such grant includes a tandem grant of DERs; will vest 50% on December 1, 2018, and 50% on December 1, 2019; and will be payable in cash to the grantee pursuant to a payment option selected by the grantee in an amount equal to the 30 day trading average closing price of the units (as defined in the plan). The vested amount then credited to the grantee's DER account will be payable in cash. See Compensation Discussion and Analysis above for discussion of the Long-Term Cash Bonuses and Phantom Common Unit awards.

The following table sets forth the percentage of each Named Executive Officer's total compensation that we paid in the form of salary and bonus:

Named Executive Officer	Year	Percentage of Total Compensation Paid as Salary and Bonus
Stanley C. Horton	2016	70%
Jamie L. Buskill	2016	67%
Michael E. McMahon	2016	77%
Jonathan E. Nathanson	2016	77%

Grants of Plan-Based Awards

The following table displays information regarding grants made during 2016 to our Named Executive Officers of Phantom Common Unit awards under our LTIP:

Grants of Plan-Based Awards for 2016

Names	Grant Date	All Other Unit Awards: Number of Units(1) (#)	Grant Date Fair Value of Unit Awards(2) ($)
Stanley C. Horton	2/4/2016	151,771	1,610,290
Jamie L. Buskill	2/4/2016	42,159	447,307
Michael E. McMahon	2/4/2016	35,835	380,209
Jonathan Nathanson	2/4/2016	35,835	380,209

(1) Represents Phantom Common Units granted under our LTIP. The fair value of each unit was derived based on the closing price of $10.61 for our common units on the NYSE on February 3, 2016. Each such grant includes a tandem grant of DERs; vests 100% on the vesting date; and will be payable to the grantee in cash, or in common units at the Board's option, upon vesting in an amount equal to the fair market value of the units (as defined in the plan) that vest on the vesting date. The vested amount then credited to the grantee's DER account will be payable in cash.
(2) Note 11 in Part II, Item 8 of this Report contains information regarding the grant date fair value of the Phantom Common Units.

Narrative Disclosure to Summary Compensation Table and Grants of Plan-Based Awards Table

The Board considers compensation awarded to the Named Executive Officers early in the following year to be attributable to the previous reporting year. Refer to Compensation Attributable to the 2016 Calendar Year for more information on compensation that the Board awarded to the Named Executive Officers related to 2016. The components of compensation earned by the Named Executive Officers have not changed from 2015 to 2016 except that in 2016, approximately 25% of the long-term incentive award was awarded in the form of Long-Term Cash Bonus awards and the remaining 75% was in the form of Phantom Common Units.

The following provides information regarding the Long-Term Cash Bonus awards that were granted to the Named Executive Officers in February 2017 and 2014, equity-based compensation awards that were granted in February 2017, 2016 and 2015 and retention awards granted to the Named Executive Officers in March 2014. Equity based-compensation awards are reportable in the Summary Compensation Table in the year of grant, whereas Long-Term Cash Bonus awards and Retention payments are reportable in the Summary Compensation Table in the year of payment.

Phantom Common Units. Each outstanding Phantom Common Unit includes a tandem grant of DERs. The grantee must select one of two irrevocable payment elections shortly after the award is granted. If the first payment election is selected, an amount equal to the fair market value of the vested portion of the Phantom Common Units and associated DERs will become payable to the grantee in cash on each of the two vesting dates. If the second payment election option is selected, the Phantom Common Units and associated DERs will become payable in cash on the second vesting date. For the Phantom Common Units granted in February 2017, half of the Phantom Common Units will vest on December 1, 2018, and the other half will vest on December 1, 2019. For the Phantom Common Units granted in February 2016, half of the Phantom Common Units will vest on December 1, 2017, and the other half will vest on December 1, 2018, and for the Phantom Common Units granted in February 2015, half vested on December 1, 2016, and the remaining half will vest on December 1, 2017. Messrs. Horton, Buskill and McMahon were granted Phantom Common Units under our LTIP in February 2017, having a grant date fair value, determined in accordance with GAAP, of $1,656,017, $490,661 and $449,785. Messrs. Horton, Buskill, McMahon and Nathanson were granted awards in February 2016 having a grant date fair value of $1,610,290, $447,307, $380,209 and $380,209 and in February 2015 having a grant date fair value, determined in accordance with GAAP, of $1,798,834, $499,670, $399,739 and $399,739.

Cash Bonus Awards. In February 2014, the Board granted to the Named Executive Officers Long-Term Cash Bonus awards. The Long-Term Cash Bonus awards vested and were paid in December 2016. The 2017 Long-Term Cash Bonuses were granted to Messrs. Horton, Buskill and McMahon in the amounts of $506,250, $150,000 and $137,500. For the Long-Term Cash

Bonus awards granted in February 2017, half of the award will vest on December 1, 2018, and the other half will vest on December 1, 2019, after the expiration of a Restricted Period, subject to the Named Executive Officer remaining continuously employed until that date, except for instances of retirement. The Named Executive Officer will become fully vested in the Long-Term Cash Bonus award upon retirement if retirement occurs 13 months after the grant date or one year after a retirement notice is provided, whichever is longer. At the end of the vesting period, our Named Executive Officers that continue to be employees are entitled to receive cash in the amount of the grant, or with respect to meeting the time requirements for retirement, are entitled to receive cash in the amount of the grant within 30 days of the initial vesting date.

Retention Program. In March 2014, because of the challenges that the Partnership was facing, the Board granted to each of the Named Executive Officers a retention award, which was made pursuant to a Retention Payment Agreement. Grants have not been made under our Retention Program since 2014. Vesting and payment of the awards will occur over a three-year period as follows: 25% vested and became payable on February 28, 2015, 25% vested and became payable on February 29, 2016, and the remaining 50% vesting and becoming payable on February 28, 2017. In order for an award to vest, the Named Executive Officer must remain continuously employed by the Partnership or a subsidiary through the applicable vesting date.

For more information about the components of compensation reported in the Summary Compensation Table, and Grants of Plan-Based Awards, please read the Compensation Discussion and Analysis.

Outstanding Equity Awards at Fiscal Year-End

The table displayed below shows the total number of outstanding equity awards in the form of Phantom Common Units awarded under our LTIP held by our Named Executive Officers at December 31, 2016:

	Phantom Common Units		
Name	Number of Units That Have Not Vested	Market Value of Units That Have Not Vested ($)	
Stanley C. Horton	57,989	1,053,080	(1)
	151,771	2,695,453	(2)
Jamie L. Buskill	16,108	292,521	(1)
	42,159	748,744	(2)
Michael E. McMahon (3)	12,886	234,010	(1)
	35,835	636,430	(2)
Jonathan E. Nathanson	12,886	234,010	(1)
	35,835	636,430	(2)

(1) The market value reported is based on the NYSE closing market price on December 30, 2016, of $17.36. These Phantom Common Units will vest on December 1, 2017. In addition to the Phantom Common Units, Messrs. Horton, Buskill, McMahon and Nathanson have accumulated non-vested DERs. Such DER amounts for Messrs. Horton, Buskill, McMahon and Nathanson were $46,391, $12,886, $10,309 and $10,309 as of December 31, 2016. Note 11 in Part II, Item 8 of this Report contains more information regarding our LTIP.
(2) The market value reported is based on the NYSE closing market price on December 30, 2016, of $17.36. These Phantom Common Units will vest 50% on December 1, 2017, and 50% on December 1, 2018. In addition to the Phantom Common Units, Messrs. Horton, Buskill, McMahon and Nathanson have accumulated non-vested DERs. Such DER amounts for Messrs. Horton, Buskill, McMahon and Nathanson were $60,708, $16,864, $14,334 and $14,334 as of December 31, 2016. Note 11 in Part II, Item 8 of this Report contains more information regarding our LTIP.
(3) As discussed in Phantom Common Units above, these awards contained payment options for which each Named Executive Officer was required to make a payment election within 30 days of the grant of the award. Mr. McMahon,

while his units vested on December 1, 2016, elected to defer payment of his award and related DER amounts until December 2017 pursuant to the payment options and provisions of the grant agreement. The vested Phantom Common Units will continue to be re-measured and accumulate DERs until settlement, pursuant to the provisions of the grant agreement.

Units Vested

The following table presents information regarding the vesting during 2016 of Phantom Common Units previously granted to our Named Executive Officers.

Units Vested for 2016

Name	Unit Awards Number of Phantom Common Units Vesting (#)	Value Received on Vesting [1] ($)
Stanley C. Horton	57,990	1,024,103
Jamie L. Buskill	16,108	284,467
Michael E. McMahon [2]	12,887	227,584
Jonathan E. Nathanson	12,887	227,584

(1) The Phantom Common Units vested December 1, 2016. At no time were our common units issued to or owned by the Named Executive Officers.

(2) As discussed in Phantom Common Units above, these awards contained payment options for which each Named Executive Officer was required to make a payment election within 30 days of the grant of the award. Mr. McMahon, while his units vested on December 1, 2016, elected to defer payment of his award and related DER amounts until December 2017 pursuant to the payment options and provisions of the grant agreement. The vested Phantom Common Units will continue to be re-measured and accumulate DERs until settlement, pursuant to the provisions of the grant agreement. A portion of these deferred units were redeemed to satisfy tax requirements.

Pension Benefits

The table displayed below shows the present value of accumulated benefits for our Named Executive Officers. Only employees of our Texas Gas subsidiary hired prior to November 1, 2006, are eligible to receive the pension benefits discussed below. Messrs. Horton, McMahon and Nathanson are, and during 2016 were, employees of our Gulf South subsidiary and are not covered under any Texas Gas benefit plans. Pension benefits include both a qualified defined benefit cash balance plan and a non-qualified defined benefit supplemental cash balance plan (SRP).

Pension Benefits for 2016

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During Last Fiscal Year ($)
Jamie L. Buskill	TGRP	30.3	641,859	—
	SRP	30.3	891,573	—

The Texas Gas Retirement Plan (TGRP) is a qualified defined benefit cash balance plan that is eligible to all Texas Gas employees hired prior to November 1, 2006. Participants in the plan vest after three years of credited service. One year of vesting service is earned for each calendar year in which a participant completes 1,000 hours of service. Eligible compensation used in calculating the plan’s annual compensation credits include total salary and bonus paid. The credit rate on all eligible compensation is 4.5% prior to age 30, 6.0% age 30 through 39, 8.0% age 40 through 49 and 10.0% age 50 and older up to the Social Security Wage Base. Additional credit rates on annual pay above Social Security Wage Base is 1.0%, 2.0%, 3.0% and 5.0% for the same age categories. On April 1, 1998, the TGRP was converted to a cash balance plan. Credited service up to March 31, 1998, is eligible for a past service credit of 0.3%. Additionally, participants may qualify for an early retirement subsidy if their combined age and service at March 31, 1998, totaled at least 55 points. The amount of the subsidy is dependent on the number of points and the participant’s age of retirement. Mr. Buskill did not meet the eligibility requirements to qualify for the early retirement subsidy. Upon retirement, the retiree may choose to receive their benefit from a variety of payment options which include a single life annuity, joint and survivor annuity options and a lump-sum cash payment. Joint and survivor benefit elections serve to reduce the amount of the monthly benefit payment paid during the retiree's life but the monthly payments continue for the life of the survivor after the death of the retiree. The TGRP has an early retirement provision that allows vested employees to retire early at age 55. Mr. Buskill is not yet eligible to receive an early retirement benefit pursuant to the TGRP.

The credited years of service appearing in the table above are the same as actual years of service. No payment was made to the Named Executive Officer during 2016. The present value of accumulated benefits payable to the Named Executive Officer, including the number of years of service credited to the Named Executive Officer, is determined using assumptions consistent with the assumptions used for financial reporting. Interest will be credited to the cash balance at December 31, 2016, commencing in 2016, using a quarterly compounding up to the normal retirement date of age 65. Salary and bonus pay credits, up to the IRC allowable limits, increase the accumulated cash balance in the year earned. Credited interest rates used to determine the accumulated cash balance at the normal retirement date as of December 31, 2016, 2015 and 2014, were 3.00%, 3.26% and 3.79% and for future years, 3.00%, 3.00% and 3.26%. The future normal retirement date accumulated cash balance was then discounted using an interest rate at December 31, 2016, 2015 and 2014, of 3.60%, 3.60% and 3.35%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2016 and 2015, of 60,999 for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

The Texas Gas SRP is a non-qualified defined benefit cash balance plan that provides supplemental retirement benefits on behalf of participating employees for earnings that exceed the IRC compensation limitations for qualified defined benefit plans, which for 2016 was $265,000. The SRP acts as a supplemental plan, therefore the eligibility and retirement provisions, the form and timing of distributions and the manner in which the present value of accumulated benefits are calculated, are similar to the same provisions as described above for the TGRP. The increase in the present value of accumulated benefit for the SRP between December 31, 2016 and 2015, of $259,129, for Mr. Buskill is reported as compensation in the Summary Compensation Table.

Nonqualified Deferred Compensation

Although we do not maintain a traditional nonqualified deferred compensation plan, the deferral option associated with the Phantom Common Unit awards is considered a form of deferred compensation and must be reported as such. The following table shows nonqualified deferred compensation plan information for Mr. McMahon, who elected to defer payment of his Phantom Common Unit award and related DER amounts under our LTIP until December 2017, pursuant to the payment options and provisions of the grant agreement:

Nonqualified Deferred Compensation

Name	Registrant Contributions in 2016 ($)	Aggregate Balance at December 31, 2016 ($)
Michael E. McMahon [1]	224,930	224,930

(1) As discussed in Phantom Common Units above, the LTIP awards contained payment options for which each Named Executive Officer was required to make a payment election within 30 days of the grant of the award. Mr. McMahon, while his units vested on December 1, 2016, elected to defer payment of his award and related DER amounts until December 2017 pursuant to the payment options and provisions of the grant agreement. The vested Phantom Common Units will continue to be re-measured and accumulate DERs until settlement, pursuant to the provisions of the grant agreement. A portion of these deferred units were redeemed to satisfy tax requirements and are not reflected in the amounts reported above.

Potential Payments Upon Termination or Change of Control

As of December 31, 2016, we did not have employment agreements with our Named Executive Officers. Our Named Executive Officers are eligible to receive accelerated vesting of cash and equity-based awards under certain of our compensation plans. As of December 31, 2016, our Named Executive Officers have outstanding grants of Phantom Common Units subject to specific vesting schedules and payment limitations, as discussed above. The Phantom Common Units will vest on a prorated basis under certain circumstances, or will become fully vested under instances of retirement subject to a time requirement, and will be payable in accordance with the provisions of the LTIP and grant agreements, as applicable, as described below. A termination of employment may also trigger a distribution of amounts from retirement plan accounts under the TGRP or the SRP. Any retirement plan distributions would be no more than those amounts disclosed in the table shown above; thus, the Potential Payments Upon Termination or Change of Control Table shown below does not include amounts attributable to the retirement plans disclosed above. In addition, in 2014, each of our Named Executive Officers were granted retention awards pursuant to a retention program approved by our Board, of which a portion had vested and paid in 2016 and 2015.

We believe that the acceleration and payment provisions contained in our various award agreements, including the retention awards, create important retention tools for us, because providing for accelerated vesting of equity-based awards upon a termination of employment for a death or disability provides employees with value in the event of a termination of employment that was beyond their control. Other companies in our industry and the general market where we compete for executive talent commonly have equity compensation plans that provide for accelerated vesting upon certain terminations of employment, and we have provided this benefit to our Named Executive Officers in order to remain competitive in attracting and retaining skilled professionals in our industry. In this discussion, prorated means the number of days in the period beginning on the grant date of the award through the termination date of the named executive officer's employment in relation to the total number of days in the vesting period.

Long-Term Incentive Plan. Within 30 days of the grant date of a Phantom Common Unit, the Named Executive Officer is required to make a payment election, which will determine if the Named Executive Officer receives payments with respect the Phantom Common Units and DERs as they vest or defer all payments until the final vesting date (subject to the acceleration and withholding of a portion of such payments to satisfy applicable tax withholding obligations. If a change in control occurs, and a Named Executive Officer’s service is terminated due to a Qualified Termination (as defined in the grant agreement), the Named Executive Officer will become automatically vested in all outstanding Phantom Common Units upon termination, but the awards will be paid pursuant to the payment option elected by the Named Executive Officer. A change of control will be deemed to occur under our LTIP upon one or more of the following events: (a) any person or group, other than our general partner or its affiliates, becomes the owner of 50% or more of our equity interests; (b) any person, other than Loews or its affiliates, become our general partner; or (c) the sale or other disposition of all or substantially all of our assets or our general partner’s assets to any person that is not an affiliate of us or our general partner. However, in the event that any award granted under our LTIP is also subject to IRC section 409A, a change of control shall have the definition of such term as found in the treasury regulations with respect to IRC section 409A.

The unvested Phantom Common Units (and all DERs associated with such Phantom Common Units) will become vested on a prorated basis upon an executive’s death or disability. Our individual form award agreements define a disability as an event that would entitle that individual to benefits under either our or one of our affiliates’ long-term disability plans (Disability). In the cases of death or Disability, the value of any then vested awards would be determined and paid at the time of termination. In the case of retirement, any outstanding and unvested awards would become fully vested upon a Named Executive Officer’s retirement and will be paid pursuant to the payment option elected. The award agreements define retirement as a termination on or after age 55, with at least 5 years of continuous service. In order to become vested in the Phantom Common Unit, retirement must occur 13 months after the grant date or one year after a retirement notice is provided, whichever is longer.

Retention Program. Each retention award was made pursuant to a Retention Payment Agreement. Vesting and payment of the awards will occur over a three-year period as follows: 25% vested and were paid on February 28, 2015, 25% vested and were paid on February 29, 2016, and the remaining 50% vesting and becoming payable on February 28, 2017. In order for an award to vest, the Named Executive Officer must remain continuously employed by the Partnership or a subsidiary through the applicable vesting date. If a Named Executive Officer's employment is terminated due to death or disability prior to the applicable vesting date, then a pro rata portion of the Retention Payment that would have become vested on the next Vesting Date following termination would be received. The retention agreement defines a disability as an event that would entitle that individual to benefits under either our or one of our affiliates' long-term disability plans.

Paid Time Off (PTO). Upon any termination of employment, the Named Executive Officers would receive the remaining accrued PTO that they accumulated during the year, if any.

Potential Payments Upon Termination or Change of Control Table

The following table represents our estimate of the amount each of our Named Executive Officers would have received upon the applicable termination or change of control event, if such event had occurred on December 31, 2016. The closing price of our common units on the NYSE on December 30, 2016, $17.36, was used to calculate these amounts. Equity values do not include the equity awards and no amounts were included for the Long-Term Cash Bonuses that were granted in 2017, as the Named Executive Officers did not hold these awards as of December 31, 2016. The amounts that any Named Executive Officer could receive upon a termination of employment or a change of control cannot be determined with any certainty until an actual termination of employment or a change of control occurs. For purposes of the below table, we have assumed all salary and bonuses were paid current as of December 31, 2016.

Potential Payments Upon Termination or Change of Control at December 31, 2016

Name	Plan Name	Change of Control ($)	Termination Other than for Cause ($)	Termination for Cause, or Voluntary Resignation ($)	Retirement ($)	Death or Disability ($)
Stanley C. Horton	LTIP (1)(2)	3,748,533	—	—	1,053,080	1,815,191
	PTO (3)	22,068	22,068	22,068	22,068	22,068
	Retention (5)	—	—	—	—	1,036,947
	Total	3,770,601	22,068	22,068	1,075,148	2,874,206
Jamie L. Buskill (4)	LTIP (2)	1,041,265	—	—	—	504,223
	PTO (3)	6,923	6,923	6,923	6,923	6,923
	Retention (5)	—	—	—	—	419,040
	Total	1,048,188	6,923	6,923	6,923	930,186
Michael E. McMahon	LTIP (1)(2)	1,095,370	—	—	458,940	643,635
	PTO (3)	10,697	10,697	10,697	10,697	10,697
	Retention (5)	—	—	—	—	454,552
	Total	1,106,067	10,697	10,697	469,637	1,108,884
Jonathan E. Nathanson	LTIP (1)(2)	870,440	—	—	234,010	418,704
	PTO (3)	6,443	6,443	6,443	6,443	6,443
	Retention (5)	—	—	—	—	426,143
	Total	876,883	6,443	6,443	240,453	851,290

(1) As of December 31, 2016, Messrs. Horton, McMahon and Nathanson were eligible for retirement as defined in the LTIP award agreement (as defined above). In order for a Phantom Common Unit to become vested due to retirement, retirement must occur 13 months after the grant date or one year after a retirement notice is provided, whichever is longer. The awards that exceed the time requirement are the LTIP awards granted in February 2015. LTIP amounts were determined by multiplying the number of Phantom Common Units each executive held on December 31, 2016, by the value of our common units on December 30, 2016, or $17.36. As of December 31, 2016, Messrs. Horton, McMahon and Nathanson held Phantom Common Units of 57,989, 25,272 and 12,886 which were granted in 2015. The DER adjustment through December 31, 2016, applicable to each Phantom Common Unit granted in February 2015, was $0.80. Except for amounts associated with Mr. McMahon's Phantom Common Units which vested in 2016 and payment was deferred until 2017, the remaining amounts will vest on December 1, 2017, and all amounts will become payable on December 1, 2017.

(2)

For LTIP amounts related to change of control, the full amount of the award would become vested in the event that the change of control definition per the award agreement has been triggered. For LTIP amounts related to death or disability, amounts were determined by multiplying the prorated number of unvested Phantom Common Units each executive held on December 31, 2016, by the value of our common units on December 30, 2016, or $17.36. For the 2015 grants, the assumed proration factor at December 31, 2016, was 0.675 for the awards vesting on December 1, 2017. As of December 31, 2016, Messrs. Horton, Buskill, McMahon and Nathanson held Phantom Common Units of 57,989, 16,108, 25,272 and 12,886 which were granted in 2015. The DER adjustment through December 31, 2016, applicable to each Phantom Common Unit granted in February 2015, was $0.80. For the 2016 grants, the assumed proration factor at December 31, 2016, was 0.498 for the awards vesting on December 1, 2017, and 0.321 for the awards vesting on December 1, 2018. As of December 31, 2016, Messrs. Horton, Buskill, McMahon and Nathanson held Phantom Common Units of 151,771, 42,159, 35,835 and 35,835 which were granted in 2016. The DER adjustment through December 31, 2016, applicable to each Phantom Common Unit granted in February 2016, was $0.40.

(3) Includes earned but unused PTO at December 31, 2016. In order to receive PTO payments upon retirement, the employee must have provided us with at least a six month notice prior to the termination of his employment.

(4) Mr. Buskill would also be entitled to receive payment under the SRP six months after termination for any reason, which amounts are reported in the Pension Benefits table.

(5) Retention amounts are determined by multiplying the portion of the Retention Payment that would have become vested on the next Vesting Date following December 31, 2016, by the proration of vesting days. The assumed proration factor at December 31, 2016, was 0.947 for the retention agreements issued in March 2014 and which vest on February 28, 2017.

Director Compensation

Each director of BGL who is not an officer or employee of us, our subsidiaries, our general partner or an affiliate of our general partner (an Eligible Director) is paid an annual cash retainer of $50,000 ($55,000 for the chairman of the Audit Committee and Conflicts Committee) payable in equal quarterly installments, and receives an annual grant of common units in an amount equal to $50,000 in which the director is immediately vested. The number of common units will be calculated by using the average of the thirty days closing market price prior to issuance. Directors who are not Eligible Directors do not receive compensation from us for their services as directors. All directors are reimbursed for out-of-pocket expenses they incur in connection with attending Board and committee meetings and will be fully indemnified by us for actions associated with being a director to the extent permitted under Delaware law.

Director Compensation for 2016

Name	Fees Earned or Paid in Cash ($)	Unit Awards [1] ($)	Total ($)
Arthur L. Rebell	57,000	50,245	107,245
William R. Cordes	57,000	50,245	107,245
Thomas E. Hyland [2]	65,000	50,245	115,245
Mark L. Shapiro [3]	62,000	50,245	112,245

(1) On February 23, 2016, Messrs. Rebell, Cordes, Hyland and Shapiro were each granted 4,277 common units. The grant date fair value of the award for each Eligible Director, based on the market price of $11.75, was $50,245. The Eligible Directors had no outstanding equity awards at December 31, 2016.

(2) Chairman of the Audit Committee.

(3) Chairman of the Conflicts Committee.

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Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth certain information, at February 15, 2017, as to the beneficial ownership of our common units by beneficial holders of 5% the outstanding common units, each member of our Board, each of the Named Executive Officers and all of our executive officers and directors as a group, based on data furnished by them. None of the parties listed in the table have the right to acquire units within 60 days.

Name of Beneficial Owner	Common Units Beneficially Owned		Percentage of Common Units Beneficially Owned (1)
Stanley C. Horton	14,000	(2)	*
Jamie L. Buskill	—		—
William R. Cordes	16,209		*
Thomas E. Hyland	22,109	(3)	*
Peter W. Keegan	—		—
Michael E. McMahon	—		—
Jonathan E. Nathanson	15,000	(4)	*
Arthur L. Rebell	54,385	(5)	*
Mark L. Shapiro	26,709		*
Kenneth I. Siegel	—		*
Andrew H. Tisch	81,050	(6)	*
All directors and executive officers as a group	229,462		*
BPHC (7)	125,586,133		50%
Loews (7)	125,586,133		50%

*Represents less than 1% of the outstanding common units

(1) As of February 15, 2017, we had 250,296,782 common units issued and outstanding.

(2) 14,000 units were purchased and are owned by Mr. Horton's spouse. In October 2015, these shares were transferred to the DWH Revocable Trust of which Mr. Horton's spouse is the beneficiary and trustee.

(3) 400 of these units are owned by Mr. Hyland's spouse.

(4) 15,000 units are owned by Mr. Nathanson's spouse.

(5) 32,984 of these units are owned by ARebell, LLC, a limited liability company controlled by Mr. Rebell. 801 units are owned by Mr. Rebell's spouse.

(6) Represents one quarter of the number of units owned by a general partnership in which a one-quarter interest is held by a trust of which Mr. Tisch is managing trustee.

(7) Loews is the parent company of BPHC and may, therefore, be deemed to beneficially own the units held by BPHC. The address of BPHC is 9 Greenway Plaza, Suite 2800, Houston, TX 77046. The address of Loews is 667 Madison Avenue, New York, New York 10065. Boardwalk GP, an indirect, wholly-owned subsidiary of BPHC, also holds our 2% general partner interest and all of our IDRs. Including the general partner interest but excluding the impact of the IDRs, Loews indirectly owns approximately 51% of our total ownership interests. Our Partnership Interests in Part II, Item 5 of this Report contains more information regarding our calculation of BPHC's equity ownership.

Securities Authorized for Issuance Under Equity Compensation Plans

In 2005, prior to the initial public offering of our common units, our Board adopted the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan. The following table provides certain information as of December 31, 2016, with respect to this plan:

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plan (excluding securities reflected in the first column)
Equity compensation plans approved by security holders	—	N/A	—
Equity compensation plans not approved by security holders	—	N/A	3,460,872

Note 11 in Part II, Item 8 of this Report contains more information regarding our equity compensation plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

It is our Board's written policy that any transaction, regardless of the size or amount involved, involving us or any of our subsidiaries in which any related person had or will have a direct or indirect material interest shall be reviewed by, and shall be subject to approval or ratification by our Conflicts Committee. "Related person" means our general partner and its directors and executive officers, holders of more than 5% of our units, and in each case, their "immediate family members," including any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law, and any person (other than a tenant or employee) sharing their household. In order to effectuate this policy, our General Counsel reviews all such transactions and reports thereon to the Conflicts Committee for its consideration. Our General Counsel also determines whether any such transaction presents a potential conflict of interest under our partnership agreement and, if so, presents the transaction to our Conflicts Committee for its consideration. In the event of a continuing service provided by a related person, the transaction is initially approved by the Conflicts Committee but may not be subject to subsequent approval. However, the Board approves the Partnership's annual operating budget which separately states the amounts expected to be charged by related parties or affiliates for the following year. No new service transactions were reviewed for approval by the Conflicts Committee during 2016 nor were there any service transactions where the policy was not followed.

Distributions are approved by the Board on a quarterly basis prior to declaration. Note 15 in Part II, Item 8 of this Report contains more information regarding our related party transactions.

See Item 10, Our Independent Directors for information regarding director independence.

Item 14. Principal Accounting Fees and Services

Audit Fees and Services

The following table presents fees billed by Deloitte & Touche LLP and its affiliates for professional services rendered to us and our subsidiaries in 2016 and 2015 by category as described in the notes to the table (in millions):

	2016	2015
Audit fees (1)	$ 2.5	$ 2.5
Audit related fees (2)	0.1	0.1
Total	$ 2.6	$ 2.6

(1) Includes the aggregate fees and expenses for annual financial statement audit and quarterly financial statement reviews.

(2) Includes the aggregate fees and expenses for services that were reasonably related to the performance of the financial statement audits or reviews described above and not included under Audit fees above, mainly including consents, comfort letters and audits of employee benefits plans.

Auditor Engagement Pre-Approval Policy

In order to assure the continued independence of our independent auditor, currently Deloitte & Touche LLP, the Audit Committee has adopted a policy requiring its pre-approval of all audit and non-audit services performed for us and our subsidiaries by the independent auditor. Under this policy, the Audit Committee annually pre-approves certain limited, specified recurring services which may be provided by Deloitte & Touche, subject to maximum dollar limitations. All other engagements for services to be performed by Deloitte & Touche must be specifically pre-approved by the Audit Committee, or a designated committee member to whom this authority has been delegated.

Since the formation of the Audit Committee and its adoption of this policy in November 2005, the Audit Committee, or a designated member, has pre-approved all engagements by us and our subsidiaries for services of Deloitte & Touche, including the terms and fees thereof, and the Audit Committee concluded that all such engagements were compatible with the continued independence of Deloitte & Touche in serving as our independent auditor.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) 1. Financial Statements

Included in Item 8 of this Report:
Report of Independent Registered Public Accounting Firm
Consolidated Balance Sheets at December 31, 2016 and 2015
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 Statements of Changes in Equity for the years ended December 31, 2016, 2015 and 2014
Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules

None.

(a) 3. Exhibits

The following documents are filed as exhibits to this report:

Exhibit Number	Description
3.1	Certificate of Limited Partnership of Boardwalk Pipeline Partners, LP (Incorporated by reference to Exhibit 3.1 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.2	Third Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP dated as of June 17, 2008 (Incorporated by reference to Exhibit 3.1 to the Registrant’s Current Report on Form 8-K filed on June 18, 2008).
3.3	Certificate of Limited Partnership of Boardwalk GP, LP (Incorporated by reference to Exhibit 3.3 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.4	Agreement of Limited Partnership of Boardwalk GP, LP (Incorporated by reference to Exhibit 3.4 to Amendment No. 1 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-127578, filed on September 22, 2005).
3.5	Certificate of Formation of Boardwalk GP, LLC (Incorporated by reference to Exhibit 3.5 to the Registrant’s Registration Statement on Form S-1, Registration No. 333-127578, filed on August 16, 2005).
3.6	Amended and Restated Limited Liability Company Agreement of Boardwalk GP, LLC (Incorporated by reference to Exhibit 3.6 to Amendment No. 4 to Registrant’s Registration Statement on Form S-1, Registration No. 333-127578, filed on October 31, 2005).
3.7	Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP, dated as of October 31, 2011 (Incorporated by reference to Exhibit 3.7 to the Registrant’s Quarterly Report on Form 10-Q filed on November 1, 2011).
3.8	Amendment No. 2 to the Third Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP, dated as of October 25, 2012 (Incorporated by reference to Exhibit 3.1 to the Registrant's Current report on Form 8-K filed on October 30, 2012).
3.9	Amendment No. 3 to the Third Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP, dated as of October 7, 2013 (Incorporated by reference to Exhibit 3.1 to the Registrant's Current report on Form 8-K filed on October 8, 2013).
4.1	Indenture dated as of June 12, 2012, between Gulf South Pipeline Company, LP and The Bank of New York Mellon Trust Company, N.A. (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on June 13, 2012).
4.2	Registration Rights Agreement dated June 12, 2012 between Gulf South Pipeline Company, LP and the Initial Purchasers (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on June 13, 2012).
4.3	Amended and Restated Registration Rights Agreement dated June 26, 2009, by and between Boardwalk Pipeline Partners, LP and Boardwalk Pipelines Holding Corp. (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on June 26, 2009).
4.4	Indenture dated July 15, 1997, between Texas Gas Transmission Corporation (now known as Texas Gas Transmission, LLC) and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 4.1 to Texas Gas Transmission Corporation’s Registration Statement on Form S-3, Registration No. 333-27359, filed on May 19, 1997).
4.5	Indenture dated as of May 28, 2003, between TGT Pipeline, LLC and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 3.6 to TGT Pipeline, LLC’s (now known as Boardwalk Pipelines, LP) Registration Statement on Form S-4, Registration No. 333-108693, filed on September 11, 2003).

4.6	Indenture dated as of May 28, 2003, between Texas Gas Transmission, LLC and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 3.5 to Boardwalk Pipelines, LLC's (now known as Boardwalk Pipelines, LP) Registration Statement on Form S-4, Registration No. 333-108693, filed on September 11, 2003).
4.7	Indenture dated as of January 18, 2005, between TGT Pipeline, LLC and The Bank of New York, as Trustee, (Incorporated by reference to Exhibit 10.1 to TGT Pipeline, LLC's (now known as Boardwalk Pipelines, LP) Current Report on Form 8-K filed on January 24, 2005).
4.8	Indenture dated as of January 18, 2005, between Gulf South Pipeline Company, LP and The Bank of New York, as Trustee (Incorporated by reference to Exhibit 10.2 to Boardwalk Pipelines, LLC's (now known as Boardwalk Pipelines, LP) Current Report on Form 8-K filed on January 24, 2005).

Exhibit Number	Description
4.9	Indenture dated as of November 21, 2006, between Boardwalk Pipelines, LP, as issuer, the Registrant, as guarantor, and The Bank of New York Trust Company, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on November 22, 2006).
4.10	Indenture dated August 17, 2007, between Gulf South Pipeline Company, LP and the Bank of New York Trust Company, N.A. therein (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on August 17, 2007).
4.11	Indenture dated January 19, 2011, between Texas Gas Transmission, LLC and the Bank of New York Trust Company, N.A. (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on January 19, 2011).
4.12	First Supplemental Indenture dated June 7, 2011, between Texas Gas Transmission, LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current report on Form 8-K, filed on June 13, 2011).
4.13	Second Supplemental Indenture dated June 16, 2011, between Texas Gas Transmission, LLC and The Bank of New York Mellon Trust Company, N.A., as Trustee (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current report on Form 8-K, filed on June 20, 2011).
4.14	Subordination Agreement, dated as of July 31, 2014, among Boardwalk Pipelines Holding Corp., as Subordinated Creditor, Wells Fargo Bank N.A., as Senior Creditor Representative, and Boardwalk Pipelines, LP, as Borrower (Incorporated by reference to Exhibit 4.1 to the Registrant’s Current Report on Form 8-K filed on August 5, 2014).
4.15	Indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP’s Current Report on Form 8-K, filed on August 21, 2009).
4.16	First Supplemental Indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.2 to Boardwalk Pipeline Partners, LP’s Current Report on Form 8-K, filed on August 21, 2009).
4.17	Second Supplemental Indenture dated November 8, 2012, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to Boardwalk Pipeline Partners, LP's Current Report on Form 8-K, filed on November 8, 2012).
4.18	First Supplemental Indenture to the indenture dated November 21, 2006, among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on April 23, 2013).
4.19	Third Supplemental Indenture to the indenture dated August 21, 2009, among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on April 23, 2013).
4.20	Fourth Supplemental Indenture to the indenture dated August 21, 2009, among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on November 26, 2014).
4.21	Fifth Supplemental Indenture to the indenture dated August 21, 2009, among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New

	York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on May 20, 2016).
10.1	Services Agreement dated as of May 16, 2003, by and between Loews Corporation and Texas Gas Transmission, LLC (Incorporated by reference to Exhibit 10.8 to Amendment No. 3 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 24, 2005). (1)
***10.2	Boardwalk Pipeline Partners, LP Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.9 to Amendment No. 4 to the Registrant's Registration Statement on Form S-1, Registration No. 333-127578, filed on October 31, 2005).
***10.3	Form of Phantom Unit Award Agreement under the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.10 to the Registrant's 2005 Annual Report on Form 10-K filed on March 16, 2006).
***10.4	Boardwalk Operating GP, LLC Short-Term Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on April 27, 2010).

Exhibit Number	Description
***10.5	Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on December 17, 2010).
*, ***10.6	Form of Phantom Unit and Cash Bonus Grant Agreement under the Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan and the Boardwalk Pipeline Partners Long-Term Incentive Plan.
***10.7	Form of Grant for Cash Bonus Awards under the Boardwalk Pipeline Partners Unit Appreciation Rights and Cash Bonus Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 12, 2014).
***10.8	Form of Retention Payment agreement. (Incorporated by reference to Exhibit 10.12 to the Registrant's Annual Report on Form 10-K filed on February 24, 2014).
***10.9	Boardwalk Operating GP, LLC Exempt Employee Annual Short-Term Incentive Plan (As Amended and Restated Effective January 1, 2013) (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on April 29, 2013).
***10.10	Form of Grant of Phantom Unit Grant Agreement under the Boardwalk Pipeline Partners Long-Term Incentive Plan (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on February 9, 2015).
10.11	Subordinated Loan Agreement dated as of July 31, 2014, between Boardwalk Pipelines, LP, as Borrower, and Boardwalk Pipelines Holding Corp., as Lender (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on August 5, 2014).
10.12	Amendment No. 1 to Subordinated Loan Agreement dated as of October 30, 2015, between Boardwalk Pipelines, LP, as Borrower, and Boardwalk Pipelines Holding Corp., as Lender. (Incorporated by reference to Exhibit 10.3 to the Registrant's Quarterly Report on Form 10-Q filed on November 3, 2015).
10.13	Amendment No. 2 to Subordinated Loan Agreement dated as of July 28, 2016, between Boardwalk Pipelines, LP, as Borrower, and Boardwalk Pipelines Holding Corp., as Lender (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on August 1, 2016).
10.14	Third Amended and Restated Revolving Credit Agreement, dated as of May 26, 2015, among Boardwalk Pipelines, LP, Texas Gas Transmission, LLC, Gulf South Pipeline Company, LP and Gulf Crossing Pipeline Company LLC, as borrowers, Boardwalk Pipeline Partners, LP, as guarantor, the several lenders and issuers party thereto, Wells Fargo Bank, N.A., as administrative agent, Citibank, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents, and Bank of China, New York Branch, Barclays Bank PLC, Deutsche Bank Securities Inc., Mizuho Bank, Ltd., MUFG Union Bank, N.A., and Royal Bank of Canada, as co-documentation agents, and Wells Fargo Securities, LLC, Citigroup Global Markets, Inc., J.P. Morgan Securities LLC, Bank of China, New York Branch, Barclays Bank PLC, Deutsche Bank Securities Inc., Mizuho Bank, Ltd., MUFG Union Bank, N.A., and RBC Capital Markets, as joint lead arrangers and joint bookrunners (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on May 26, 2015).
10.15	Amendment No. 1 to the Third Amended and Restated Revolving Credit, dated as of July 29, 2016, among Boardwalk Pipelines, LP, Texas Gas Transmission, LLC, Gulf South Pipeline Company, LP and Gulf Crossing Pipeline Company LLC, as borrowers, Boardwalk Pipeline Partners, LP, as guarantor, the several lenders and issuers party thereto, Wells Fargo Bank, N.A., as administrative agent, Citibank, N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents, and Bank of China, New York Branch, Barclays Bank PLC, Deutsche Bank Securities Inc., Mizuho Bank, Ltd., MUFG Union Bank, N.A., and Royal Bank of Canada, as co-documentation agents, and Wells Fargo Securities, LLC, Citigroup Global Markets, Inc., J.P. Morgan Securities LLC, Bank of China, New York Branch, Barclays Bank PLC, Deutsche Bank Securities Inc., Mizuho Bank, Ltd., MUFG Union Bank, N.A., and RBC Capital Markets, as joint lead

	arrangers and joint bookrunners (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed on August 1, 2016).
10.16	Sixth Supplemental Indenture to the indenture dated August 21, 2009, by and among Boardwalk Pipelines, LP, as issuer, Boardwalk Pipeline Partners, LP, as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (Incorporated by reference to Exhibit 4.1 to the Registrant's Current Report on Form 8-K filed on January 18, 2017).
*12.1	Statement of Computation of Ratio of Earnings to Fixed Charges.
*21.1	List of Subsidiaries of the Registrant.
*23.1	Consent Of Independent Registered Public Accounting Firm.
*31.1	Certification of Stanley C. Horton, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*31.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
**32.1	Certification of Stanley C. Horton, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Exhibit Number	Description
**32.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101.INS	XBRL Instance Document
*101.SCH	XBRL Taxonomy Extension Schema Document
*101.CAL	XBRL Taxonomy Calculation Linkbase Document
*101.DEF	XBRL Taxonomy Extension Definitions Document
*101.LAB	XBRL Taxonomy Label Linkbase Document
*101.PRE	XBRL Taxonomy Presentation Linkbase Document

* Filed herewith
** Furnished herewith
*** Management contract or compensatory plan or arrangement

(1) The Services Agreements between Gulf South Pipeline Company, LP and Loews Corporation and between Boardwalk Pipelines, LP (formerly known as Boardwalk Pipelines, LLC) and Loews Corporation are not filed because they are identical to exhibit 10.1 except for the identities of Gulf South Pipeline Company, LP and Boardwalk Pipelines, LLC and the date of the agreement.

SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

		Boardwalk Pipeline Partners, LP By: Boardwalk GP, LP its general partner By: Boardwalk GP, LLC its general partner	
Dated:	February 15, 2017	By:	/s/ Jamie L. Buskill
			Jamie L. Buskill Senior Vice President, Chief Financial and Administrative Officer and Treasurer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the date indicated.

Dated:	February 15, 2017	/s/ Stanley C. Horton Stanley C. Horton President, Chief Executive Officer and Director (principal executive officer)
Dated:	February 15, 2017	/s/ Jamie L. Buskill Jamie L. Buskill Senior Vice President, Chief Financial and Administrative Officer and Treasurer (principal financial officer)
Dated:	February 15, 2017	/s/ Steven A. Barkauskas Steven A. Barkauskas Senior Vice President, Controller and Chief Accounting Officer (principal accounting officer)
Dated:	February 15, 2017	/s/ William R. Cordes William R. Cordes Director
Dated:	February 15, 2017	/s/ Thomas E. Hyland Thomas E. Hyland Director
Dated:	February 15, 2017	/s/ Peter W. Keegan Peter W. Keegan Director
Dated:	February 15, 2017	/s/ Arthur L. Rebell Arthur L. Rebell Director
Dated:	February 15, 2017	/s/ Mark L. Shapiro Mark L. Shapiro Director
Dated:	February 15, 2017	/s/ Kenneth I. Siegel Kenneth I. Siegel

		Director
Dated:	February 15, 2017	/s/ Andrew H. Tisch
		Andrew H. Tisch
		Director