

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2008

OR

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

Commission file number: 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:

| <u>Title of each class</u> | <u>Name of each exchange on which registered</u> |
|-----------------------------|--|
| Common Units | |
| Representing Limited | New York Stock Exchange |
| Partner Interests | |

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 ☒ No ☐

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

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 ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer 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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐

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

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2008, was approximately \$1.1 billion. As of February 13, 2009, the registrant had 154,934,609 common units outstanding and 22,866,667 Class B units outstanding.

Documents incorporated by reference. None.

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PART I

Item 1. Business

Introduction

We are a Delaware limited partnership formed in 2005. Our business is conducted by our subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas). Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 107.5 million of our common units, all 22.9 million of our class B units and, through Boardwalk GP, LP, an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of our incentive distribution rights (IDRs). The common units, class B units and general partner interest owned by BPHC represent approximately 74% of our equity interests, excluding the IDRs. *Our Partnership Interests*, in Item 5 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).

Our Business

Through our subsidiaries, we own and operate three interstate natural gas pipeline systems including integrated storage facilities. Our pipeline systems originate in the Gulf Coast region and extend northeasterly to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio. The pipeline portion of the Gulf Crossing assets was placed in service in January and February 2009.

We serve a broad mix of customers, including marketers, local distribution companies (LDCs), producers, electric power generation plants, interstate and intrastate pipelines and direct industrial users. Our transportation and storage rates and general terms and conditions of service are established by, and subject to review and revision by, the Federal Energy Regulatory Commission (FERC). These rates are designed based upon certain assumptions to allow us the opportunity to recover the cost of providing our transportation and storage services and earn a reasonable return on equity. However, it is possible that we may not recover those costs or earn a reasonable return. Our firm and interruptible storage rates for Gulf South and the storage services associated with Phase III of the Western Kentucky Storage Expansion project on Texas Gas are market-based pursuant to authority granted by FERC.

We provide a significant portion of our pipeline transportation and storage services through firm contracts under which our customers pay monthly capacity reservation charges (which are charges owed regardless of actual pipeline or storage capacity utilization). Other charges are based on actual utilization of the capacity. For the twelve months ended December 31, 2008, approximately 66% of our revenues were derived from capacity reservation charges under firm contracts, approximately 22% of our revenues were derived from charges based on actual utilization under firm contracts and approximately 12% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL) and other services.

Our Pipeline and Storage Systems

Our operating subsidiaries own and operate approximately 14,000 miles of pipeline, directly serving customers in twelve states and indirectly serving customers throughout the northeastern and southeastern United States (U.S.) through numerous interconnections with unaffiliated pipelines. In 2008, our pipeline systems transported approximately 1.7 trillion cubic feet (Tcf) of gas. Average daily throughput on our pipeline systems during 2008 was approximately 4.8 billion cubic feet (Bcf). Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 160.0 Bcf. We conduct all of our natural gas transportation and integrated storage operations through our operating subsidiaries as one segment.

The principal sources of supply for our pipeline systems are regional supply hubs and market centers located in the Gulf Coast region, including offshore Louisiana, the Perryville, Louisiana area, the Henry Hub in Louisiana, and Agua Dulce and Carthage, Texas. The Gulf Crossing Expansion and Fayetteville and Greenville Laterals will provide us access to unconventional Mid-Continent supplies such as the Caney Woodford Shale in southeast Oklahoma and the Fayetteville

Shale in Arkansas. Carthage, Texas, provides access to natural gas supplies from the Bossier Sands, Barnett Shale and other gas producing regions in eastern Texas. The Henry Hub serves as the designated delivery point for natural gas futures contracts traded on the New York Mercantile Exchange. We also access wellhead supplies in northern and southern Louisiana and Mississippi, imported liquefied natural gas (LNG) through several Gulf Coast LNG terminals, one of which is directly connected to our pipeline systems, and Canadian natural gas through an unaffiliated pipeline interconnect at Whitesville, Kentucky.

Our Gulf Crossing System

In the first quarter 2009, we placed in service the pipeline portion of our Gulf Crossing Project consisting of approximately 350 miles of 42-inch pipeline originating near Sherman, Texas, and proceeding to the Perryville, Louisiana area. We expect Gulf Crossing's initial compression facilities to be placed in service during the first quarter 2009. Gulf Crossing's supply sources are mainly unconventional gas sources in the Barnett Shale and Caney Woodford Shale. The end markets for Gulf Crossing are in the Midwest, Northeast, Southeast and Florida through interconnections with Texas Gas, Gulf South and unaffiliated pipelines. See Expansion Projects for more information regarding our Gulf Crossing Project.

Our Gulf South System

Our Gulf South pipeline system is located along the Gulf Coast in the states of Texas, Louisiana, Mississippi, Alabama and Florida. This system is composed of:

- approximately 7,700 miles of pipeline, having a peak-day delivery capacity of approximately 5.0 Bcf per day;
- 38 compressor stations having an aggregate of approximately 378,900 horsepower; and
- two natural gas storage fields located in Louisiana and Mississippi, having aggregate storage capacity of approximately 131.0 Bcf of gas, of which approximately 83.0 Bcf is designated as working gas.

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 across the system, including New Orleans, Louisiana; Jackson, Mississippi; Mobile, Alabama; and Pensacola, Florida, and 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 other interstate and intrastate pipelines and storage facilities. These pipeline interconnections provide access to markets throughout the northeastern and southeastern U.S.

Gulf South's Bistineau, Louisiana, gas storage facility has approximately 78.0 Bcf of working gas storage capacity, with a maximum injection rate of 480 million cubic feet (MMcf) per day and a maximum withdrawal rate of 870 MMcf per day. Gulf South currently sells firm and interruptible storage services at Bistineau under FERC-approved market-based rates. Gulf South's Jackson, Mississippi, gas storage facility has approximately 5.0 Bcf of working gas storage capacity, with a maximum injection rate of 100 MMcf per day and a maximum withdrawal rate of 250 MMcf per day. The Jackson gas storage facility is used for operational purposes and its capacity is not offered for sale to the market.

Our Texas Gas System

Our Texas Gas pipeline system originates in Louisiana and in East Texas and runs north and east through Louisiana, Arkansas, Mississippi, Tennessee, Kentucky, Indiana, and into Ohio, with smaller diameter lines extending into Illinois. This system is composed of:

- approximately 5,950 miles of pipeline, having a peak-day delivery capacity of approximately 3.8 Bcf per day which includes deliveries to pipeline interconnects in southern Louisiana;
- 31 compressor stations having an aggregate of approximately 552,700 horsepower; and
- nine natural gas storage fields located in Indiana and Kentucky, having aggregate storage capacity of approximately 180.0 Bcf of gas, of which approximately 77.0 Bcf is designated as working gas.

The market area directly served by Texas Gas 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 the Northeast through interconnections with unaffiliated pipelines.

Texas Gas owns a majority of the gas in its storage fields which it uses to meet the operational requirements of its transportation and storage customers and the requirements of its no-notice transportation service (NNS), which allows customers to draw from storage gas during the winter season to be repaid in-kind during the following summer season. A large portion of the gas delivered by the Texas Gas system is used for heating, resulting in higher daily requirements during winter months. Texas Gas also offers summer no-notice transportation service (SNS) designed primarily to meet the needs of electrical power generation facilities during the summer season.

Expansion Projects

Pipeline Expansion Projects:

The following paragraphs describe in more detail each of our recently completed and ongoing pipeline expansion projects:

Southeast Expansion. We have constructed and placed in service 111 miles of 42-inch pipeline and related compression assets, originating near Harrisville, Mississippi, and extending to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco Station 85). The pipeline currently has 1.8 Bcf of peak-day transmission capacity. We have applied to the Pipelines and Hazardous Materials Safety Administration (PHMSA) for authority to operate under a special permit that would allow the pipeline to be operated at higher operating pressures, thereby increasing the peak-day transmission capacity to 1.9 Bcf per day. Customers have contracted at fixed rates for substantially all of the operational capacity of this pipeline, with such contracts having a weighted-average term of approximately 9.3 years (including a capacity lease agreement with Gulf Crossing). In February 2009, we placed in service the remaining compression assets related to this project and construction on this project is complete.

Gulf Crossing Project. In January and February 2009, we completed construction and placed in service the pipeline portion of the assets associated with our Gulf Crossing Project, which consists of approximately 357 miles of 42-inch pipeline that begins near Sherman, Texas, and proceeds to the Perryville, Louisiana area. We expect the initial compression to be placed in service during the first quarter 2009, providing Gulf Crossing with a peak-day transmission capacity of 1.2 Bcf per day. We have applied to PHMSA for authority to operate under a special permit that would allow the pipeline to be operated at higher operating pressures, thereby increasing its peak-day transmission capacity to 1.4 Bcf per day. The peak-day transmission capacity would increase from 1.4 Bcf per day to 1.7 Bcf per day following the construction of additional compression facilities which we expect to place in service in the first quarter 2010, subject to FERC approval. Customers have contracted at fixed rates for substantially all of the operational capacity of this pipeline, with such contracts having a weighted-average term of approximately 9.5 years.

Fayetteville and Greenville Laterals. We are constructing two laterals on our Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by our existing interstate pipelines. The Fayetteville Lateral will originate in Conway County, Arkansas, and proceed southeast through the Bald Knob, Arkansas area, to an interconnect with the Texas Gas mainline in Coahoma County, Mississippi, consisting of approximately 165 miles of 36-inch pipeline. The Greenville Lateral will originate at the Texas Gas mainline near Greenville, Mississippi, and proceed east to the Kosciusko, Mississippi area, consisting of approximately 95 miles of 36-inch pipeline. The Greenville Lateral will provide customers access to additional markets, located primarily in the Midwest, Northeast and Southeast. In December 2008, we placed in service the header, or first 66 miles, of the Fayetteville Lateral. In January 2009, we placed in service a portion of the Greenville Lateral which originates at our Texas Gas mainline and continues to an interconnect with the Tennessee 800 line in Holmes County, Mississippi. Included in the Fayetteville header is a section of 18-inch pipeline under the Little Red River in Arkansas which will be replaced with 36-inch pipeline once a new horizontal directional drill is completed under the river. We expect the 36-inch pipeline installation to be completed in the second quarter 2009. The initial peak-day transmission capacity of each of these laterals is approximately 0.8 Bcf per day.

During 2008, we executed contracts for additional capacity that will require us to add compression to increase the peak-day transmission capacity of these laterals to approximately 1.3 Bcf per day for the Fayetteville Lateral and 1.0 Bcf per day for the Greenville Lateral. To meet this requirement we will add compression facilities to this project and we have

applied to PHMSA for authority to operate under a special permit that would allow the Fayetteville Lateral to be operated at higher operating pressures, in addition to replacing the section of 18-inch pipeline noted above. We expect the new compression to be in service during 2010, subject to FERC approval. Customers have contracted at fixed rates for substantially all of the operational capacity of these laterals, with such contracts having a weighted-average term of approximately 9.9 years.

Prior to placing a new pipeline or lateral in service, we conduct extensive tests to ensure that the pipeline can operate safely at normal operating pressures. Further, to operate at higher operating pressures under the PHMSA special permits discussed above, we design, build and conduct additional stringent tests to ensure the pipeline's integrity. In performing such tests on one of our pipeline expansions we discovered some anomalies in a small number of pipe segments installed on the East Texas to Mississippi segment of our Gulf South pipeline system (the East Texas Pipeline). As a result, and as a prudent operator, we elected to reduce operating pressures on this pipeline to 20% below its previous operating level, which was below the pipeline's maximum non-special permit operating pressures, while we investigate further and replace the affected pipe segments where necessary. We have notified PHMSA of these anomalies and our ongoing testing and remediation plans and we will keep them informed as our activities progress. For a further discussion, see Item 1A, *Risk Factors* and Item 7, *MD&A – Factors that Impact our Results of Operations*.

Storage Expansion Project:

We are also engaged in the following storage expansion project:

Western Kentucky Storage Expansion Phase III. We are developing 8.3 Bcf of new working gas capacity at our Midland storage facility, for which FERC has granted us market-based rate authority. This expansion is supported by 10-year precedent agreements for 5.1 Bcf of storage capacity. In the fourth quarter 2008, we placed in service approximately 5.4 Bcf of storage capacity. We are in discussion with potential customers for the remaining capacity which we expect to place in service in the fourth quarter 2009.

Nature of Contracts

We contract with our customers to provide transportation services and storage services on a firm and interruptible basis. We also provide combined firm transportation and storage services, which we refer to as NNS and SNS. In addition, we provide interruptible PAL services.

Transportation Services. We offer transportation services on both a firm and interruptible basis. Our customers choose, based upon their particular needs, the applicable mix of services depending upon availability of pipeline capacity, price of service and the volume and timing of the customer's requirements. Firm transportation customers reserve a specific amount of pipeline capacity at specified receipt and delivery points on our system. Firm customers generally pay fees based on the quantity of capacity reserved regardless of use, plus a commodity and fuel charge paid on the volume of 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 related to NNS agreements. Firm transportation contracts generally range in term from one to ten years, although firm transportation contracts can be offered for terms less than one year. In providing interruptible transportation service, we agree to transport gas for a customer when capacity is available. Interruptible 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.

Storage Services. We offer customers 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 it is 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. Unlike most FERC-regulated pipelines, Gulf South is authorized to charge market-based rates for its firm and interruptible storage and Texas Gas is authorized to charge market-based rates for the firm and interruptible storage services associated with Phase III of its Western Kentucky Storage Expansion project.

No-Notice Service and Summer No-Notice Service. NNS and SNS consist of a combination of firm transportation and storage services that allow customers to withdraw gas from storage with little or no notice. Customers pay a reservation

charge based upon the capacity reserved plus a commodity and fuel charge based on the volume of gas actually transported. In accordance with its tariff, Texas Gas loans stored gas to 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) gas into or out of our pipeline systems at a specific location for a specific period of time. Customers pay for PAL service in advance or on a monthly basis depending on the terms of the agreement.

Customers and Markets Served

We transport natural gas for a broad mix of customers, including marketers, LDCs, producers, electric power generators, intrastate and interstate pipelines and direct industrial users located throughout the Gulf Coast, Midwest and Northeast regions of the U.S. Our Gulf Crossing system moves gas from mainly unconventional gas sources, the Barnett and Caney Woodford Shales, to the midwest, northeast, southeast and Florida through interconnects with Texas Gas and Gulf South as well as other interstate pipelines. Customers on our Gulf South system are located throughout its service area and indirect customers are accessed through numerous interconnects on unaffiliated pipeline systems. Our Texas Gas system primarily moves gas for its customers in a northeasterly direction to serve markets directly connected to its system and also serves indirect customer markets through interconnects with other interstate pipelines.

We contract directly with end-use customers and with marketers, producers and other third parties who provide transportation and storage services to end-users. Based on 2008 revenues, our customer mix was as follows: marketers (49%), LDCs (21%), producers (16%), power generators (6%), pipelines (3%) and industrial users and others (5%). Based upon 2008 revenues, our deliveries were as follows: pipeline interconnects (43%), LDCs (27%), storage activities (9%), power plants (6%), industrial end-users (5%) and other (10%). There were no customers that made up more than 10% of our 2008 operating revenues; however, as our remaining expansion projects are completed in 2009 and 2010, we expect that our customer mix will change. Please refer to Item 1A, *Risk Factors*, regarding risks associated with our customers and changing customer mix.

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 supply management, transportation and storage services to support the needs of the other customer groups. Some of the marketers are sponsored by LDCs and, to a lesser extent, producers.

LDCs. Most of our LDC customers use firm transportation services, including NNS. We serve approximately 185 LDCs located across our pipeline systems. The demand of these customers peaks during the winter heating season.

Producers. Producers of natural gas use our services to transport gas supplies from producing areas, primarily shale plays in Texas, Oklahoma and Arkansas, to supply pools and to the other customer groups, both on and off of our systems. Producers contract with us for storage services to store excess production and optimize the ultimate sales prices for their gas.

Power Generators. We have the ability to serve major electrical power generators in ten states. We are directly connected to several large natural gas-fired power generation facilities, some of which are also directly connected to other pipelines. The demand of the power generating customers peaks during the summer cooling season which is counter to the winter season peak demands of the LDCs. Most of our power-generating customers use a combination of SNS, firm and interruptible transportation services.

Pipelines (off-system). Our pipeline systems serve as feeder pipelines for long-haul interstate pipelines serving markets throughout the midwestern, northeastern and southeastern portions of the U.S. We have numerous interconnects with third-party interstate and intrastate pipelines.

Industrial End Users. We provide industrial facilities with a combination of firm and interruptible transportation services. Our 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 pipelines.

Competition

We compete with numerous interstate and intrastate pipelines throughout our service territory to provide transportation and storage services for our customers. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing pipelines and will compete with several new pipeline projects that are under construction, including the Rockies Express Pipeline that will transport natural gas from northern Colorado to eastern Ohio and the Mid-Continent Express Pipeline that would transport gas from Texas to Alabama. The principal elements of competition among pipelines are available capacity, rates, terms of service, access to supply and flexibility and reliability of service. We compete with these pipelines to maintain current business levels and to serve new demand and markets. We also compete with other pipelines for contracts with producers that would support new growth projects such as our pipeline expansion projects discussed elsewhere in this report. In addition, regulators' continuing efforts to increase competition in the natural gas industry have increased the natural gas transportation options of our traditional customers. As a result of the regulators' policies, segmentation and capacity release have created an active secondary market which increasingly competes with our pipeline services, particularly on our Texas Gas system. Additionally, natural gas competes with other forms of energy available to our customers, including electricity, coal, and fuel oils. To the extent usage of natural gas decreases due to competition from other fuel sources, throughput on our system may decrease and the need for customers to contract for our services may decrease. Despite these competitive conditions, substantially all of the operating capacity on our pipeline systems, including our expansion projects, is sold out with a weighted-average contract life of over 6 years.

Seasonality

Our revenues can be seasonal in nature, affected by weather and natural gas price volatility. Weather impacts natural gas demand for power generation and heating needs, which in turn influences the short-term value of transportation and storage across our pipeline systems. Colder than normal winters or warmer than normal summers typically result in increased pipeline transportation revenues. Peak demand for natural gas typically occurs during the winter months, driven by heating needs. Excluding the impact of our expansion projects that went into service in 2008, during 2008 approximately 54% of our total operating revenues were recognized in the first and fourth calendar quarters. The effects of seasonality on our revenues have been mitigated over the past several years due to the increased use of gas-fired power generation in the summer months to meet cooling needs, primarily in the Southeast and Midwest. Generally, revenues from our expansion projects will be less seasonal in nature due to the structure of the contracts and the fact that the capacity is held primarily by producers, who are seeking a market for their production. We expect the impact of seasonality to further decline in coming years as the full impact of revenues from our expansion projects is taken into account.

Government Regulation

FERC regulates our pipelines under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. 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 operating subsidiaries hold certificates of public convenience and necessity issued by FERC covering certain of their facilities, activities and services. FERC also prescribes accounting treatment for our pipelines which is separately reported pursuant to forms filed with FERC. The regulatory books and records and other activities of our pipelines may be periodically audited by FERC.

The maximum rates that may be charged by Gulf Crossing, Gulf South and Texas Gas for gas transportation are established through FERC's cost-of-service rate-making process. The maximum rates that may be charged by us for storage services on Texas Gas, with the exception of Phase III of the Western Kentucky Storage Expansion, are also established through FERC's cost-of-service rate-making process. Key determinants in the cost-of-service rate-making process are the costs of providing service, the allowed rate of return, throughput assumptions, the allocation of costs and the rate design. Texas Gas is prohibited from placing new rates into effect prior to November 1, 2010, and neither Gulf South nor Texas Gas has an obligation to file a new rate case. Gulf Crossing will have to either file a rate case or justify its initial firm transportation rates within three years after the pipeline is fully placed in service.

We are also regulated by the U.S. Department of Transportation (DOT) under the Natural Gas Pipeline Safety Act of 1968, as amended by Title I of the Pipeline Safety Act of 1979, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas pipelines. In addition, we will require authority from PHMSA to operate our expansion pipelines, under a special permit, at higher operating pressures in order to transport all of the volumes we have contracted for with customers on our expansion projects.

Our operations are also subject to extensive federal, state, and local laws and regulations relating to protection of the environment. Such 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 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. These laws include, for example:

- the Clean Air Act and analogous state laws which impose obligations related to air emissions;
- the Water Pollution Control Act, commonly referred to as the Clean Water Act, and analogous state laws which regulate discharge of wastewaters 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; and
- 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.

Item 1A, *Risk Factors*, includes further discussion regarding our environmental risk factors.

Effects of Compliance with Environmental Regulations

Note 3 in Item 8 of this Report contains information regarding environmental compliance.

Employee Relations

At December 31, 2008, we had 1,128 employees, approximately 90 of whom are covered by a collective bargaining agreement which expires in April 2011. A satisfactory relationship continues to exist 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 group life, hospital, and medical benefits, as well as disability benefits. 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 10 in Item 8 of this Report contains further discussion of 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 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 website at www.sec.gov. 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 free of charge within the "Governance" section of our website, and in print to any unitholder who requests, 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. We have described below some of the more material risks which we and our subsidiaries face. There may be additional risks that we do not yet know of or that we do not currently perceive to be material that may also impact our business or the business of our subsidiaries.

Each of the risks and uncertainties described below could lead to events or circumstances that may have a material adverse effect on our business, financial condition, results of operations and 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 are undertaking large, complex expansion projects which involve significant risks that may adversely affect our business.

We are currently undertaking several large, complex pipeline and storage expansion projects, as discussed under Business – Expansion Projects, and we may also undertake additional expansion projects in the future. In pursuing these and previous projects, we experienced significant cost overruns and we may experience cost increases in the future. We also experienced construction delays and may experience additional delays in the future. Delays in construction could result from a variety of factors and have resulted in penalties under customer contracts such as liquidated damage payments and could in the future result in similar losses. In some cases, certain customers could have the right to terminate their transportation agreements if the related expansion project is not completed by a date specified in their precedent agreements.

The cost overruns and construction delays we experienced have resulted from a variety of factors, including the following:

- delays in obtaining regulatory approvals;
- difficult construction conditions, including adverse weather conditions and encountering higher density rock formations than anticipated;
- delays in obtaining key materials; and
- shortages of qualified labor and escalating costs of labor and materials resulting from the high level of construction activity in the pipeline industry.

In pursuing current or future expansion projects, we could experience additional delays or cost increases for the reasons described above or as a result of other factors. We may not be able to complete our current or future expansion projects on the expected terms, cost or schedule, or at all. In addition, we cannot be certain that, if completed, these projects will perform in accordance with our expectations. Other areas of our business may suffer as a result of the diversion of our management's attention and other resources from our other business concerns to our expansion projects. Any of these factors could have a material adverse effect on our ability to realize the anticipated benefits from our expansion projects. See Business – Expansion Projects for more information regarding our expansion projects.

Completion of our expansion projects will require us to raise significant amounts of debt and equity financing. Ongoing disruption of the credit and capital markets may hinder or prevent us and our customers from meeting future capital needs.

Global financial markets and economic conditions have been, and continue to be, experiencing extraordinary disruption and volatility following adverse changes in global capital markets. Recently, market conditions have resulted in numerous bankruptcies, insolvencies, forced sales of financial institutions as well as market intervention by governments around the globe. The debt and equity capital markets are exceedingly distressed and banks and other commercial lenders have substantially curtailed their lending activities as a result of, among other things, significant write-offs in the financial services sector, the re-pricing of credit risk and current weak economic conditions. These circumstances continue to make it difficult to obtain funding.

As a result, the cost of raising money in the debt and equity capital markets and commercial credit markets has increased substantially while the availability of funds from those markets has diminished significantly. Many lenders and institutional investors have increased interest rates, enacted tighter lending standards, refused to refinance existing debt at maturity – at all or on terms similar to the debt being refinanced – and reduced and in some cases ceased to provide funding to borrowers. In some cases, lenders under existing revolving credit facilities have been unwilling or unable to meet their funding obligations, including one lender under our revolving credit facility. If additional lenders under our credit facility were to fail to fund their share of the credit facility, our borrowing capacity could be further reduced. Although Loews has indicated that it is willing to invest additional capital in us to finance our expansion projects to the extent the public markets remain unavailable on acceptable terms, we have not committed to any transaction at this time and any additional investment by Loews would be subject to agreement by Loews and to review and approval by our independent Conflicts Committee. Due to these factors, we cannot be certain that new debt or equity financing will be available on acceptable terms or that we will be able to continue to access the full amount of the remaining commitments under our revolving credit facility in the future.

These circumstances have impacted our business, or may impact our business in a number of ways including but not limited to:

- limiting the amount of capital available to us to fund new growth capital projects and acquisitions, which would limit our ability to grow our business, take advantage of business opportunities, respond to competitive pressures and increase distributions to our unitholders;
- adversely affecting our ability to refinance outstanding indebtedness at maturity on favorable or fair terms or at all; and
- weakening the financial strength of certain of our customers, increasing the credit risk associated with those customers and/or limiting their ability to grow which could affect their ability to pay for our services or prompt them to reduce throughput or contracted capacity on our pipelines.

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

Our revolving credit agreement contains operating and financial covenants that may restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, 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. The agreement also requires us to maintain a ratio of consolidated debt to consolidated earnings before interest, taxes, depreciation and amortization (as defined in the agreement) of no more than five to one, which limits the amount of additional indebtedness we can incur. Future financing agreements we may enter into may contain similar or more restrictive covenants.

Our ability to comply with the covenants and restrictions contained in our credit agreement may be affected by events beyond our control, including prevailing economic, financial and industry conditions. If market or other 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 would be dilutive to our existing equity holders. 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. In such event, we would not have, and may not be able to obtain, sufficient funds to make these accelerated payments.

A portion of the expected maximum daily capacity of our pipeline expansion projects is contingent on our receiving and maintaining authority from PHMSA to operate at higher operating pressures.

Our ability to transport a portion of the expected maximum capacity on each of our expansion project pipelines is contingent on our receipt of authority to operate these pipelines at higher operating pressures under special permits issued by PHMSA. The ability to operate at higher operating pressures increases the transportation capacity of the pipelines. We have received both the special permit and the authority to operate from PHMSA for the East Texas Pipeline, which was completed in 2008. We have also received the special permits for our Southeast, Gulf Crossing and Fayetteville and

Greenville Laterals, but we have not received authority from PHMSA to operate under these permits. Absent such authority, we will not be able to transport all of the contracted quantities of natural gas on these pipelines. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher operating pressures. To the extent PHMSA does not grant us authority to operate any of our expansion pipelines under a special permit or withdraws previously granted authority, our transportation capacity made available to the market and our transportation revenues would be reduced.

We have discovered anomalies in a small number of pipe segments on the East Texas Pipeline. As a result, and as a prudent operator, we have elected to reduce operating pressures on this pipeline to 20% below its previous operating level, which was below the pipeline's maximum non-special permit operating pressures. We do not expect to return to normal operating pressures, or to operate at higher pressures under the special permit, until after we have completed our investigation and remediation measures, as appropriate, and PHMSA has concurred with our determination to increase operating pressures. Operating at lower pressures reduces the amount of gas that can flow through a pipeline and therefore will reduce our expected revenues and cash flow from the affected pipeline. In addition, we will incur costs to replace defective pipe segments on the East Texas Pipeline and expect to temporarily shut down the East Texas Pipeline when performing the necessary remedial measures, up to and including replacing certain pipe segments. We cannot determine at this time the amount of costs we will incur or when we might raise the operating pressures on this pipeline. We have not completed testing all of our expansion pipelines and could find anomalies on other pipelines which could have similar impacts with respect to those pipelines. We will not receive authority from PHMSA to operate any of our expansion pipelines at higher pressures under special permits until we have fully tested and, as needed, remediated any anomalies on each such pipeline.

We are exposed to credit risk relating to nonperformance by our customers.

Credit risk relates to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. Our exposure generally relates to 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. If any of our significant customers have credit or financial problems which result in a delay or failure to pay for services provided by us or contracted for with us, or to repay the gas they owe us, it could have a material adverse effect on our business. In addition, our FERC gas tariffs only allow us to require limited credit support in the event that our transportation customers are unable to pay for our services. As contracts expire, the failure of any of our customers could also result in the non-renewal of contracted capacity. Item 7A of this Report contains more information on credit risk arising from gas loaned to customers.

Upon completion of our expansion projects, our customer mix will have changed, leading to changes in credit risk.

Historically, the customers accounting for the majority of our throughput and revenues have been gas marketers and LDCs with investment grade ratings. After completion of our current expansion projects, producers of natural gas as a group will comprise a significantly larger portion of our throughput and revenues. We expect one producer to represent over 10% of our 2009 revenues. Historically, producers have had lower credit ratings than LDCs and marketers. Therefore the expected change in our customer base could result in higher total credit risk. The loss of access to credit for any of our major customers, or a systemic loss of access to credit for any customer group in the aggregate, could reduce our receipt of payment for services rendered or otherwise reduce the level of services required by our customers.

We depend on certain key customers for a significant portion of our revenues. The loss of any of these key customers could result in a decline in our revenues.

We rely on a limited number of customers for a significant portion of revenues. We may be unable to negotiate extensions or replacements of contracts and key customers on favorable terms. The loss of all or even a portion of the contracted volumes of these customers, as a result of competition, creditworthiness or otherwise, could have a material adverse effect on our business, unless we are able to contract for comparable volumes from other customers at favorable rates.

Increased competition could result in lower contracted capacity on our pipelines, decreased rates for our services and reduced revenues.

We compete primarily with other interstate and intrastate pipelines in the transportation and storage of natural gas. Competition is particularly strong in the Midwest and Gulf Coast states where we compete with numerous existing

pipelines and will compete with several new pipeline projects that are under construction, such as the Rockies Express Pipeline and the Mid-Continent Express Pipeline. We also compete with other pipelines for contracts with producers that would support new growth projects such as our pipeline expansion projects. Natural gas also competes with other forms of energy available to our customers, including electricity, coal and fuel oils. The principle elements of competition among pipelines are availability of capacity, rates, terms of service, access to gas supplies, flexibility and reliability. FERC's policies promote competition in gas markets by increasing the number of gas transportation options available to our customer base. Increased competition could reduce the volumes of gas transported by our pipeline systems or, in instances where we do not have long-term contracts with fixed rates, could force us to decrease our transportation or storage rates. Competition could intensify the negative impact of factors that could significantly decrease demand for natural gas in the markets served by our pipeline systems, such as a recession or adverse economic conditions, weather, higher fuel costs and taxes or other governmental or regulatory actions that directly or indirectly increase the cost or limit the use of natural gas. Our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows could be adversely affected by competition.

The regulatory program that applies to interstate pipelines is different than the regulatory program that applies to many of our competitors that are not regulated interstate pipelines. This difference in regulatory oversight can result in longer lead times to develop and complete a project when it is regulated at the federal level. We compete against a number of intrastate pipelines which have significant regulatory advantages over us because of the absence of FERC regulation. In view of potential rate advantages and construction and service flexibility available to intrastate pipelines, we may lose customers and throughput to intrastate competitors.

Significant changes in energy prices could affect supply and demand, reduce system throughput and adversely affect our revenues and available cash.

Due to the natural decline in traditional gas production connected to our system, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control including the price level of natural gas. In general terms, the price of natural gas fluctuates in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic conditions;
- weather conditions, seasonal trends and hurricane disruptions;
- the relationship between the available supplies and the demand for natural gas;
- the availability of LNG;
- the availability of adequate transportation capacity;
- storage inventory levels;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of, and changes in, governmental regulation and taxation; and
- the anticipated future prices of natural gas, LNG and other commodities.

Since the summer of 2008, the price level of natural gas has dropped substantially. It is difficult to predict future changes in gas prices, however the recent global economic slowdown would generally indicate a bias toward downward pressure on prices rather than an increase. Further downward movement in gas prices could negatively impact producers in nontraditional supply areas such as the Barnett Shale, the Bossier Sands, the Caney Woodford Shale and the Fayetteville Shale, including producers who have contracted for capacity on our expansion projects. Significant financial difficulties experienced by our producer customers could impact their ability to pay for services rendered or otherwise reduce their demand for our services.

High natural gas prices may result in a reduction in the demand for natural gas. A reduced level of demand for natural gas could reduce the utilization of capacity on our systems, reduce the demand for our services and could result in the non-renewal of contracted capacity as contracts expire.

Our natural gas transportation and storage operations are subject to FERC's rate-making policies which could limit our ability to recover the full cost of operating our pipelines, including earning a reasonable return.

We are subject to extensive regulations relating to the rates we can charge for our transportation and storage operations. For the cost-based services we offer, FERC establishes both the maximum and minimum rates we can charge. The basic elements that FERC considers are the cost of providing the service, the volumes of gas being transported, how costs are allocated between services and the rate of return a pipeline is permitted to earn. While neither Gulf South nor Texas Gas has an obligation to file a rate case, our Gulf Crossing pipeline has an obligation to file either a rate case or a cost-and-revenue study within three years of being placed in service to justify its rates. Customers of our subsidiaries or FERC can challenge the existing rates on any of our pipelines. Such a challenge could adversely affect our ability to establish reasonable transportation rates, 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 a reasonable opportunity to recover current costs and depreciation and earn a reasonable return. Additionally, FERC can propose changes or modifications to any of its existing rate-related policies.

If our subsidiaries were to file a rate case or if we have to defend our rates in a proceeding commenced by a customer or FERC, we would be required, among other things, to establish that the inclusion of an income tax allowance in our cost of service is just and reasonable. Under current FERC policy, since we are a limited partnership and do not pay U.S. federal income taxes, this would require us to show that our unitholders (or their ultimate owners) are subject to federal income taxation. To support such a showing our general partner may elect to require owners of our units to recertify their status as being subject to U.S. federal income taxation on the income generated by our subsidiaries or we may attempt to provide other evidence. We can provide no assurance that the evidence we might provide to FERC will be sufficient to establish that our unitholders (or their ultimate owners) are subject to U.S. federal income tax liability on the income generated by our jurisdictional pipelines. If we are unable to make such a showing, FERC could disallow a substantial portion of the income tax allowance included in the determination of the maximum rates that may be charged by our pipeline subsidiaries, which could result in a reduction of such maximum rates from current levels.

We may not be able to recover all of our costs through existing or future rates. An adverse determination in any future rate proceeding brought by or against any of our subsidiaries could have a material adverse effect on our business.

Our natural gas transportation and storage operations are subject to extensive regulation by FERC in addition to FERC rules and regulations related to the rates we can charge for our services.

FERC's regulatory authority extends to:

- operating terms and conditions of service;
- the types of services we may offer to our customers;
- construction of new facilities;
- creation, extension or abandonment of services or facilities;
- accounts and records; and
- relationships with certain types of affiliated companies involved in the natural gas business.

FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, to construct new facilities, offer new services or to recover the full cost of operating our pipelines. This regulatory oversight can result in longer lead times to develop and complete an expansion project. The federal regulatory approval and compliance process could raise the costs of such projects to the point where they are no longer sufficiently timely or cost competitive when compared to competing projects that are not subject to the federal regulatory regime.

FERC regulates the type of services we can offer, the terms and conditions of those services and has authority to review pipeline contracts to ensure that the services, rates and charges are just and reasonable and not unduly discriminatory. FERC has various regulatory policies upon which it relies to protect against undue discrimination. One such policy is to monitor the terms and conditions of transportation service contracts for any material deviation from the pipeline's tariff. If FERC determines that a term of any such contract, at the time it is entered into or during the term of that agreement, deviates in a material manner from a pipeline's tariff, FERC can, among other potential remedies, order the pipeline to remove the term from the contract and execute and re-file a new contract with FERC, or alternatively, amend its

tariff to include the deviating term, thereby offering it to all shippers. If FERC audits a pipeline's contracts or other aspects of our pipeline business and finds material deviations or other violation, FERC could conduct a formal enforcement investigation, resulting in penalties and/or ongoing compliance obligations.

Should we fail to comply with all applicable statutes, rules, regulations and orders administered or issued by FERC, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the NGA to impose penalties for current violations of up to \$1.0 million per day for each violation.

Capacity leaving our Lebanon, Ohio terminus is limited.

The northeastern terminus of our pipeline systems is in Lebanon, Ohio, where it connects with other interstate natural gas pipelines delivering gas to Northeast, Midwest and East Coast markets. Pipeline capacity into Lebanon is significantly greater than pipeline capacity leaving that point, creating a bottleneck for supply into areas of high demand. This situation may be compounded when the Rockies Express pipeline reaches Lebanon later in 2009 while the remaining segments of that pipeline downstream of Lebanon are still under construction. As of December 31, 2008, approximately 55% of our long-term contracts with firm deliveries to Lebanon will expire or have the ability to terminate by the end of 2010. Supply volumes from the Rocky Mountains, Canada and LNG import terminals may compete with and displace volumes from the Gulf Coast and Mid-Continent in order to serve the Northeast, Midwest and East Coast markets.

We may not be able to maintain or replace expiring gas transportation and storage contracts at favorable rates.

Our primary exposure to market risk occurs at the time existing transportation contracts expire and are subject to renegotiation. As of December 31, 2008, approximately 17% of the contracts for firm transportation capacity on our pipeline systems, excluding agreements related to the expansion projects not yet in service, was due to expire on or before December 31, 2009. Upon expiration, we may not be able to extend contracts with existing customers or obtain replacement contracts at favorable rates or on a long-term basis. A key determinant of the value that customers can realize from firm transportation on a pipeline and the price they are willing to pay for transportation is the price differential between physical locations, which can be affected by, among other things, the availability of supply, available capacity, storage inventories, weather and general market demand in the respective areas.

The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- existing and new competition to deliver natural gas to our markets;
- the growth in demand for natural gas in our markets;
- whether the market will continue to support long-term contracts;
- the current price differentials, or market price spreads between two points on our pipelines; and
- the effects of state regulation on customer contracting practices.

If third-party pipelines and other facilities connected to our pipelines and facilities become unavailable to transport natural gas our revenues could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines. For example, we are contractually committed to deliver approximately 1.8 Bcf per day to Transco Station 85. If this or any other significant pipeline connection were to become unavailable for current or future volumes of natural gas due to repairs, damage to the facilities, lack of capacity or any other reason, our ability to continue shipping natural gas to end markets could be restricted, thereby reducing our revenues.

We are subject to laws and regulations relating to the environment which may expose us to significant costs, liabilities and loss of revenues.

Our operations are subject to extensive federal, state and local laws and regulations relating to protection of the environment. These laws include, for example the Clean Air Act; the Water Pollution Control Act, commonly referred to as the Clean Water Act; CERCLA or the Superfund law; the Resource Conservation and Recovery Act and analogous state laws. The existing environmental regulations could be revised or reinterpreted in the future and new laws and regulations could be adopted or become applicable to our operations or facilities. In addition, government action may be initiated to

reduce greenhouse gas emissions along with other government actions that may have the effect of requiring or encouraging reduced consumption or production of natural gas.

Compliance with current or future environmental regulations could require significant expenditures and the failure to comply with current or future regulations might result in the imposition of fines and penalties. Current rate structures, customer contracts and prevailing market conditions might not allow us to recover the additional costs incurred to comply with new environmental requirements and we might not be able to obtain or maintain all required environmental regulatory approvals for certain projects. If there is a delay in obtaining any required environmental regulatory approvals or if we fail to obtain and comply with them, we may be required to shut down certain facilities or become subject to additional costs.

We do not own all of the land on which our pipelines and facilities are located, which could disrupt our operations or result in increased costs.

We obtain the rights to construct and operate certain of our pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. As a result, we are subject to the risk of increased costs to maintain necessary use of land in accordance with the agreements that convey to us those rights. Additionally, if we do not comply with the terms of those agreements our rights could be restricted which could disrupt our operations.

We are subject to strict safety regulations which may impose significant costs and liabilities on us.

Under PHMSA regulations, we are required to develop and maintain integrity management programs to comprehensively evaluate certain areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as high consequence areas where a leak or rupture could potentially do the most harm. The regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, the addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Any repair, remediation, preventative or mitigating actions may require significant capital and operating expenditures.

We are also subject to the requirements of the Occupational Safety and Health Act (OSHA) and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA hazard communication standard requires that we maintain information about hazardous materials used or produced in our operations and that we provide this information to employees, state and local governmental authorities and local residents.

Should we fail to comply with PHMSA regulations, or OSHA, state statutes and general industry standards regulating the protection of the health and safety of workers, keep adequate records or monitor pipeline integrity or occupational exposure to regulated substances we could be subject to penalties and fines and/or otherwise incur significant costs to restore compliance.

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 our natural gas transportation and storage operations such as leaks, explosions and mechanical problems. 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, explosions, severe winter weather and fires. 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 near populated areas, including 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 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. Recent changes in the insurance markets have made it more difficult for us to obtain certain types of coverage. The insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or all potential losses.

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, completely protect them against a terrorist attack or obtain adequate insurance coverage for terrorist acts at reasonable rates. These developments have subjected our operations to increased risks and could have a material adverse effect on our business. In particular, we might experience increased capital or operating costs to implement increased security.

We face risks associated with global climate change.

There is a growing belief that emissions of greenhouse gases, most notably carbon dioxide, may be linked to global climate change, which has been associated with extreme weather events and other risks. While there is currently no federal regulation of greenhouse gas emissions in the U.S., some states have adopted such laws and it is anticipated that federal legislation, likely consisting of a cap and trade system, will be enacted in the U.S. in the near future. In addition, the U.S. Environmental Protection Agency may regulate certain carbon dioxide and other greenhouse gas emissions and some greenhouse gases may be regulated as “air pollutants” under the Clean Air Act. Depending on the particular regulation adopted, we could be required to purchase and surrender allowances for greenhouse gas emissions resulting from our operations (e.g., our compressor units). In addition, compliance with any new federal or state laws and regulations requiring adoption of greenhouse gas control programs or imposing restrictions on emissions of carbon dioxide in areas of the U.S. in which we conduct business could adversely affect the demand for and the cost to produce and transport natural gas which would adversely affect our business.

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.

At December 31, 2008, BPHC, a subsidiary of Loews, owned a majority of our limited partner interests 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 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.
- 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 additional amounts of entity-level taxation for state tax purposes, then our cash distributions to our unitholders could 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 a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. 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, which is currently a maximum of 35%, 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 flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our common units.

Current tax law may change, causing us to be treated as a corporation for federal income tax purposes or otherwise subjecting us to additional amounts of entity-level taxation for state tax purposes. For example, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. Imposition of such a tax on us would reduce the cash available for distribution to unitholders.

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, then the minimum quarterly distribution amount and the target distribution amounts will be adjusted to reflect the impact of that law on us.

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

The present federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by legislative, judicial or administrative changes and differing interpretations at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Recently, members of Congress have considered substantive changes to the existing U.S. tax laws that would affect certain publicly traded partnerships. Although it does not appear that the legislation considered would have affected our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will be reconsidered or will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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

We have not requested any ruling from the IRS with respect to our treatment as a partnership for federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions that we take. Therefore, it may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we

take and even then a court may not agree with some or all of 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. In addition, because the costs of any contest with the IRS will be borne indirectly by our unitholders and our general partner, any such contest will result in a reduction in cash available for distribution.

Our unitholders may be required to pay taxes on their share of our income even if such unitholders do not receive any cash distributions from us.

Our unitholders will be treated as partners to whom we will allocate taxable income and who 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 such unitholders receive cash distributions from us. Our 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 that results from such unitholders' share of our taxable income.

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

If our unitholders sell their common units, such unitholders will recognize gain or loss equal to the difference between the amount realized and such unitholders' tax basis in those common units. Distributions in excess of our unitholders' allocable share of our net taxable income decrease their tax basis in their common units. Accordingly, to the extent a unitholder's distributions have exceeded such unitholder's allocable share of our net taxable income, the sale of units by such unitholder will produce taxable income to them 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 items, including depreciation recapture. 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 our common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, such as employee benefit plans and individual retirement accounts (known as 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 could be taxable to them. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file U.S. 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 purchased. The IRS may challenge this treatment, which could result in a decrease in the value of the common units.

Because we cannot match transferors and transferees of common units we will adopt depreciation and amortization positions that may not conform with all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could decrease 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 any 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 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 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 use of this proration method may not be permitted under existing Treasury Regulations. If the IRS were to challenge this method or new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned 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 a unitholder whose units are loaned to a “short seller” to cover a short sale of units may be considered as having disposed of the loaned units, 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 to the short seller, 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 loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from borrowing their units.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between the general partner and the unitholders. The IRS may challenge this treatment, which could adversely affect the value of the common units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to our assets to the capital accounts of our unitholders and our general partner. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain unitholders and the general partner, which may be unfavorable to such unitholders. Moreover, under our valuation methods, subsequent purchasers of common units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to our tangible assets and a lesser portion allocated to our intangible assets. The IRS may challenge our valuation methods, or our allocation of the Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the general partner and certain of our unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the 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 profit interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

We will be considered terminated 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. Our termination would, among other things, result in the closing of our taxable year which would require us to file two tax returns (and could result in our unitholders receiving two Schedules K-1) for one fiscal year, and could result in a deferral of depreciation deductions allowable in computing our taxable income. In the case of a unitholder reporting on a taxable year other than a fiscal year ending December 31, the closing of our taxable year may also result in more than twelve months of our taxable income or loss being includable in such unitholder’s taxable income for the year of termination. Our termination currently would not affect our classification as a partnership for federal income tax purposes. We would be treated as a new partnership for tax purposes and would be required to make new tax elections and could be subject to penalties if we were unable to determine in a timely manner that a termination occurred.

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, 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 do 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 twelve 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 108,000 square feet of office space in Owensboro, Kentucky, in a building that we own. Our operating subsidiaries own their respective pipeline systems in fee. However, a substantial portion of these systems is 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 on our material property, including our pipelines and storage facilities.

Item 3. Legal Proceedings

For a discussion of certain of our current legal proceedings, please read Note 3 in Item 8 of this Report.

Item 4. Submission of Matters to a Vote of Security Holders

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, 2008, we had outstanding 154.9 million common units, 22.9 million class B units, a 2% general partner interest and incentive distribution rights (IDRs). The common units and class B units together 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 107.5 million of our common units, all 22.9 million of our class B units and, through Boardwalk GP, LP, an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of the IDRs. The common units, class B units and general partner interest held by BPHC represent approximately 74% of our equity interests. 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, 2009, we had 154.9 million common units outstanding held by approximately 60 holders of record. BPHC owns 107.5 million of our common units and all of our class B units, for which there is no established public trading market. 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, 2009, was \$22.44 per unit.

| | Sales Price Range per Common Unit | | Cash Distributions per Common Unit |
|-------------------------------|--------------------------------------|----------|--|
| | High | Low | (a) (b) |
| Year ended December 31, 2008: | | | |
| Fourth quarter | \$ 25.97 | \$ 14.00 | \$ 0.480 |
| Third quarter | 24.96 | 17.11 | 0.475 |
| Second quarter | 28.65 | 23.34 | 0.470 |
| First quarter | 32.25 | 21.24 | 0.465 |
| Year ended December 31, 2007: | | | |
| Fourth quarter | \$ 33.33 | \$ 29.76 | \$ 0.46 |
| Third quarter | 37.79 | 28.80 | 0.45 |
| Second quarter | 37.46 | 32.65 | 0.44 |
| First quarter | 39.20 | 30.13 | 0.43 |

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

(b) We also paid cash distributions to our general partner with respect to its 2% general partner interest and, with respect to that portion of the distribution in excess of \$0.4025 per unit, its incentive distribution rights described below. The class B unitholder participates in distributions on a pari passu basis with our common units up

to \$0.30 per quarter, beginning with the distribution attributable to the third quarter 2008. The class B units do not participate in quarterly distributions above \$0.30 per unit.

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. 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, 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 Item 1A, *Risk Factors*, of this Report.

Incentive Distribution Rights

IDRs represent 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. In 2008 and 2007, we paid \$7.5 million and \$2.5 million in distributions on behalf of our IDRs. There were no amounts paid on behalf of our IDRs in 2006.

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 that quarter among the unitholders and our general partner as follows:

| | Total Quarterly Distribution | Marginal Percentage Interest in Distributions | |
|----------------------------|-------------------------------|---|-----------------|
| | | Limited Partner Unitholders | General Partner |
| | Target Amount | (1) | |
| 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% |

- (1) Distributions to our limited partner unitholders include distributions on behalf of our class B units as described under Issuance of Class B Units.

Issuance of Class B Units

In June 2008, we issued and sold to BPHC, approximately 22.9 million class B units representing limited partner interests for \$30.00 per class B unit. The class B units share in quarterly distributions of available cash from operating surplus on a pari passu basis with our common units, until each common unit and class B unit has received a quarterly distribution of \$0.30. The class B units do not participate in quarterly distributions above \$0.30 per unit. The class B units began sharing in income allocations and distributions with respect to the third quarter 2008.

The class B units have the same voting rights as if they were outstanding common units and are entitled to vote as a separate class on any matters that materially adversely affect the rights or preferences of the class B units in relation to other classes of partnership interests or as required by law. The class B units will be convertible into common units upon demand by the holder on a one-for-one basis at any time after June 30, 2013.

Conversion of Subordinated Units

In November 2008, we satisfied the last of the earnings and distributions tests contained in our partnership agreement for the conversion of all the 33.1 million outstanding subordinated units held by BPHC into common units on a one-for-one basis. The last of these requirements was met coincident with payment of the quarterly distribution paid in the fourth quarter 2008. Two days following this quarterly distribution to unitholders, all of the subordinated units converted to common units.

Equity Compensation Plans

For information about our equity compensation, see Securities Authorized for Issuance under Equity Compensation Plans in Item 12 of this Report.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data

The following table presents summary historical financial and operating data for us and our predecessor Boardwalk Pipelines, as of the dates and for the periods indicated. In connection with the consummation of our initial public offering (IPO), BPHC contributed all of the equity interests in Boardwalk Pipelines to us. This contribution was accounted for as a transfer of assets between entities under common control in accordance with Statement of Financial Accounting Standards (SFAS) No. 141, *Business Combinations*. Therefore, the results of Boardwalk Pipelines prior to November 15, 2005, have been combined with our results subsequent to November 15, 2005, as our consolidated results for 2005.

The acquisition of Gulf South by Boardwalk Pipelines in December 2004 was accounted for using the purchase method of accounting. Accordingly, the post-acquisition financial information included below reflects the purchase. As a result, our results of operations for the year 2004 are not readily comparable with our results of operations for the years subsequent to 2004.

Prior to its converting to a limited partnership on November 15, 2005, Boardwalk Pipelines' taxable income was included in the consolidated federal income tax return of Loews and Boardwalk Pipelines recorded a charge-in-lieu of income taxes pursuant to a tax-sharing agreement with Loews. The tax-sharing agreement required Boardwalk Pipelines to remit to Loews on a quarterly basis any federal income taxes as if it were filing a separate return. Boardwalk Pipelines and its subsidiaries were also included in the state franchise tax filings of BPHC. The franchise taxes were charged to, and recorded by, Boardwalk Pipelines and its subsidiaries pursuant to the companies' tax sharing policy. Following our IPO, we no longer record certain state franchise taxes incurred by BPHC and no longer participate in a tax-sharing agreement with Loews. Our subsidiaries directly incur some income-based state taxes, which are shown as Income taxes on the Consolidated Statements of Income.

As used herein, EBITDA means earnings before interest, income taxes, and depreciation and amortization. This measure is not calculated or presented in accordance with accounting principles generally accepted in the U.S. (GAAP). We explain this measure below and reconcile it to its most directly comparable financial measures calculated and presented in accordance with GAAP in “***Non-GAAP Financial Measure.” The financial data below should be read in conjunction with the consolidated financial statements and notes thereto included in this Report (in millions, except Earnings per common and subordinated unit, Earnings per class B unit and Distributions per common unit):

| Boardwalk Pipeline Partners, LP | | | | | |
|--|-----------------|----------|-------------|----------|----------|
| For the Year Ended December 31, | | | | | |
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| Total operating revenues | \$ 784.8 | \$ 643.2 | \$ 607.6 | \$ 560.5 | \$ 263.6 |
| Net income | 294.0 | 227.7 | 197.6 | 100.9 | 48.8 |
| Total assets (a) | 6,721.6 | 4,122.0 | 2,909.2 | 2,437.9 | 2,443.8 |
| Long-term debt | 2,889.4 | 1,847.9 | 1,350.9 | 1,101.3 | 1,106.1 |
| Earnings per common and subordinated unit ** | \$ 1.98 | \$ 1.87 | \$ 1.85 | * | N/A |
| Earnings per class B unit ** | \$ 0.60 | \$ - | \$ - | \$ - | N/A |
| Distributions per common unit | \$ 1.87 | \$ 1.74 | \$ 1.32 (b) | \$ - | N/A |
| EBITDA*** | \$ 474.6 | \$ 349.8 | \$ 331.5 | \$ 289.0 | \$ 144.5 |

- (a) Total assets for the periods prior to 2008 were revised to conform with the 2008 presentation which reflects a change in accounting policy regarding recording customer-owned gas held in storage to the more preferable method of not recording the gas on the balance sheet. As a result, Total assets decreased \$35.3 million, \$42.1 million, \$27.6 million and \$28.3 million, in 2007, 2006, 2005 and 2004. Note 2 in Item 8 contains more information regarding this change.
- (b) The first quarter 2006 distribution represented a prorated portion of the \$0.35 per unit “minimum quarterly distribution” (as defined in our partnership agreement) for the period November 15, 2005 through December 31, 2005.

* Our net income was \$36.0 million, or \$0.35 per common and subordinated unit, for the period from November 15, 2005, the closing date of our initial public offering, through December 31, 2005.

**** Earnings per Unit**

We calculate net income per limited partner unit in accordance with Emerging Issues Task Force (EITF) Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*. In Issue 3 of EITF No. 03-6, the EITF reached a consensus that undistributed earnings for a period should be allocated to a participating security based on the contractual participation rights of the security to share in those earnings as if all of the earnings for the period had been distributed. Our general partner holds all of our IDRs which are contractual participation rights as described in Item 5 of this Report under *Incentive Distribution Rights*. The amounts reported for net income per limited partner unit on the Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006, were adjusted to take into account an assumed incremental allocation to the general partner's IDRs. Payments made on account of the IDRs are determined in relation to actual declared distributions.

In June 2008, we issued and sold approximately 22.9 million class B units. These class B units began sharing in earnings allocations on July 1, 2008. In November 2008, all of the 33.1 million subordinated units converted to common units.

*****Non-GAAP Financial Measure**

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 financial performance without regard to financing methods, capital structure or historical cost basis;
- our ability to generate cash sufficient to pay interest on our indebtedness and to make distributions to our partners;
- our operating performance and return on invested capital as compared to those of other companies in the natural gas transportation, gathering and storage business, without regard to financing methods and capital structure; and
- the viability of acquisitions and capital expenditure projects.

EBITDA should not be considered an alternative to, or more meaningful than, net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP, or as an indicator of our operating performance or liquidity. Certain items excluded from EBITDA 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. However, viewing EBITDA as an indicator 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 other than making distributions. EBITDA is not necessarily comparable to a similarly titled measure of another company.

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

| Boardwalk Pipeline Partners, LP | | | | | |
|---|-----------------|-----------------|-----------------|-----------------|-----------------|
| For the Year Ended December 31, | | | | | |
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| Net income | \$ 294.0 | \$ 227.7 | \$ 197.6 | \$ 100.9 | \$ 48.8 |
| Income taxes and charge-in-lieu of income taxes | 1.0 | 0.8 | 0.2 | 49.5 | 32.3 |
| Elimination of cumulative deferred taxes | - | - | - | 10.1 | - |
| Depreciation and amortization | 124.8 | 81.8 | 75.8 | 72.1 | 34.0 |
| Interest expense | 57.7 | 61.0 | 62.1 | 60.1 | 30.1 |
| Interest income | (2.9) | (21.5) | (4.2) | (1.5) | (0.3) |
| Interest income from affiliates, net | - | - | - | (2.2) | (0.4) |
| EBITDA | \$ 474.6 | \$ 349.8 | \$ 331.5 | \$ 289.0 | \$ 144.5 |

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

The following discussion and analysis of financial condition and results of operations should be read in conjunction with our consolidated financial statements and the related notes thereto, included in Item 8, and with Item 1A, Risk Factors.

Overview

Through our subsidiaries, Gulf Crossing, Gulf South and Texas Gas, we own and operate three interstate natural gas pipeline systems including integrated storage facilities. Our pipeline systems originate in the Gulf Coast region and extend northeasterly to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio.

Our pipeline systems contain approximately 14,000 miles of pipeline, directly serving customers in twelve states and indirectly serving customers throughout the northeastern and southeastern U.S. through numerous interconnections with unaffiliated pipelines. In 2008, our pipeline systems transported approximately 1.7 Tcf of gas resulting in average daily throughput of approximately 4.8 Bcf. Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 160.0 Bcf. We conduct all of our natural gas transportation and integrated storage operations through our operating subsidiaries operating as one segment.

Our transportation services consist of firm transportation, whereby the customer pays a capacity reservation charge to reserve pipeline capacity at certain receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume of natural gas actually transported, and interruptible transportation, whereby the customer pays to transport gas only when capacity is available and used. We offer firm 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. Some PAL agreements are paid for at inception of the service and revenues for these agreements are recognized as service is provided over the term of the agreement. For the year ended December 31, 2008, the percentage of our total operating revenues associated with firm contracts was approximately 88%.

We are not in the business of buying and selling natural gas other than for system management purposes, but changes in the price of natural gas can affect the overall supply and demand of natural gas, which in turn can affect our results of operations. Our business is affected by trends involving natural gas price levels and natural gas price spreads, including spreads between physical locations on our pipeline system, which affect our transportation revenues, and spreads in natural gas prices across time (for example summer to winter), which primarily affect our storage and PAL revenues.

Recent Events

As of February 18, 2009, we have substantially completed our announced expansion projects, including recently placing the following assets in service:

- Phase III of our Western Kentucky Storage Expansion;
- the first 66 miles of our Fayetteville Lateral, which includes a temporary river crossing;
- the remaining compression related to our Southeast Expansion;
- the pipeline portion of our Gulf Crossing Project; and
- a portion of our Greenville Lateral.

For more information regarding our expansion projects see Expansion Projects in Item 1 of this Report.

We recently signed precedent agreements for 0.2 Bcf per day of capacity that will support expanding our system from the Haynesville production area in northwest Louisiana to Perryville, Louisiana. This project will consist of adding compression to our Gulf South system at an estimated cost of up to \$105 million. We expect to finance this project with additional debt and expect to place this project in service in the fourth quarter 2010, subject to regulatory approvals.

On February 5, 2009, we announced a quarterly distribution of \$0.48 per unit, payable on February 23, 2009 to unitholders of record as of February 16, 2009.

In January 2009, we borrowed the remaining unfunded commitments under our revolving credit facility, which increased borrowings under the facility to \$953.5 million.

Factors that Impact our Results of Operations

A significant portion of our operating revenues is derived from reservation charges under multi-year firm contracts, therefore the risk of revenue fluctuations due to near-term changes in natural gas supply and demand conditions, competition and price volatility is significantly mitigated. For the year ended December 31, 2008, 66% of our operating revenues were associated with reservation charges under firm contracts which do not vary based on capacity utilization. Excluding contracts associated with our expansion projects currently under construction, the weighted average contract life of our contracts is approximately 4.1 years. Regardless of these factors, our business can be impacted by shifts in supply and demand dynamics, the mix of services requested by customers and by competition and regulatory requirements, particularly when accompanied by downturns or sluggishness in the economy, especially over a longer term.

Changing Customer Mix and Credit Profile

After completion of our expansion projects, producers will comprise a larger portion of our revenues, both as a group and separately. We expect producers as a group to contribute a much more significant portion of our future revenues, and one producer to represent over 10% of our 2009 revenues. Historically producers have had lower credit ratings than LDCs and LDC-sponsored marketing companies, which have typically accounted for a large portion of our revenues. Therefore the expected change in our customer base could result in higher total credit risk.

Current economic conditions also indicate that many of our customers may encounter increased credit risk in the near term. We actively monitor the credit status of our counterparties and to date have not had any significant credit defaults associated with our transactions. However, given the current volatility in the financial markets, we cannot be certain that we will not experience such losses in the future. Item 1A, *Risk Factors*, of this Report contains more information regarding the risks related to our customer base.

Competition and Contract Renewals

We compete primarily with other interstate and intrastate pipelines in the transportation and storage of natural gas, particularly in the Midwest and Gulf Coast states where we compete with numerous existing pipelines and will compete with pipelines under construction such as the Rockies Express Pipeline and the Mid-Continent Express Pipeline. We compete for renewals of expiring transportation and storage contracts, as well as new transportation contracts that will support growth projects.

Despite these competitive conditions, substantially all of the operating capacity on our expansion projects is sold out and our legacy systems are supported by long-term contracts having an average remaining life of 4.1 years. However, as of December 31, 2008, approximately 17% of the firm contract load on our pipeline systems, excluding agreements related to the expansion projects not yet in service, was due to expire on or before December 31, 2009. In addition, approximately 55% of our long-term contracts with firm deliveries to Lebanon, Ohio, the northeastern terminus of our pipeline system, will expire or become terminable by the customer by the end of 2010. In 2008, we were successful in remarketing and renewing the approximately 25% of our firm contract load that was due to expire during that year, in many cases obtaining favorable rates and extended contract terms. Notwithstanding that success, however, the 2009 and 2010 contract expirations and termination rights create uncertainty as we cannot give assurances that we will successfully remarket this capacity. Our ability to remarket available capacity will be impacted by additional competition from newly constructed pipelines, fluctuating commodity prices, a recessionary economy which could impact demand for and supply of natural gas and numerous other factors beyond our control. Item 1A, *Risk Factors*, contains more information regarding the risks related to competition in our industry.

Natural Gas Prices

High natural gas prices in recent years have driven increased production levels in producing locations such as the Bossier Sands and Barnett Shale gas producing regions in East Texas, which have resulted in widened basis differentials on our systems and have benefited our transportation revenues. The high natural gas prices have also driven increased production in regions such as the Fayetteville Shale in Arkansas and the Caney Woodford Shale in Oklahoma, which,

together with the higher production levels in East Texas, have formed the basis for several pipeline expansion projects including those constructed and being undertaken by us.

The price for natural gas has declined since its peak in the late summer 2008, although average prices continue to remain at elevated levels from those seen historically. Many of our customers have been negatively impacted by these recent declines in natural gas prices as well as current conditions in the capital markets, which factors have caused several of our producer customers to announce plans to decrease drilling levels and, in some cases, to consider shutting in natural gas production from some producing wells, which could adversely affect the volumes of natural gas we transport. While the majority of our revenue is derived from capacity reservation charges that are not impacted by the volume of natural gas transported; a significant portion of our revenue, approximately 34% in 2008, is derived from charges based on actual volumes transported under firm and interruptible services. As a result, lower volumes of natural gas transported would result in lower revenues from natural gas transportation operations. Based on the significant level of revenue we receive from reservation capacity charges under long-term contracts and our review of the recent announcements of drilling plans by our customers, we do not expect the current level of natural gas prices to have a significant adverse effect on our operating results. However, we cannot give assurances that this will be the case, or that commodity prices will not decline further, which could result in a further reduction in drilling activities by our customers.

In addition, spreads in natural gas prices between time periods, such as winter to summer, impact our PAL and interruptible storage revenues. These period to period price spreads, which were favorable for our PAL and interruptible storage services during 2006 and early 2007, decreased substantially in 2007 and continued to decrease into 2008, which resulted in reduced PAL and interruptible storage revenues for those periods. We cannot predict future time period spreads or basis differentials.

Reduction of Operating Pressures on Expansion Pipelines; Applications for Special Permits from PHMSA

As discussed elsewhere in this report, we have discovered anomalies in a small number of pipe segments on our East Texas Pipeline. As a result, and as a prudent operator, we have elected to reduce operating pressures on that pipeline to 20% below its previous operating level, which was below the pipeline's maximum non-special permit operating pressures. Operating at lower pressures reduces the amount of gas that can flow through a pipeline and therefore will reduce our expected revenues and cash flow. We do not expect to return to normal operating pressures, or to operate at higher pressures under the special permit discussed below, until after we have completed our investigation and remediation measures, as appropriate, and PHMSA has concurred with our determination to increase pressures. We will also incur costs to replace defective pipe segments on the East Texas Pipeline, some of which may be reimbursable from vendors, and expect to temporarily shut down that pipeline when performing the necessary remedial measures, up to and including replacing certain pipe segments. We will work with PHMSA to return the East Texas Pipeline to its previous status under the special permit after we have completed our investigation and remediation. We cannot determine at this time the amount of costs we will incur or when we might raise operating pressures. We have not completed testing on all of our expansion pipelines and could find anomalies on other pipelines which could have similar impacts with respect to those pipelines.

Our ability to transport a portion of the expected maximum capacity on each of our expansion project pipelines is contingent upon our receipt of authority to operate these pipelines at higher operating pressures under special permits issued by PHMSA. We have received authority to operate the East Texas Pipeline under a special permit and have received the special permits for our Southeast, Gulf Crossing and Fayetteville and Greenville Laterals, but we have not received authority to operate under these permits. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate any of our pipelines at higher operating pressures. Absent such authority, we will not be able to transport all of the contracted for quantities of natural gas on these pipelines. To the extent that PHMSA does not grant us authority to operate any of our expansion pipelines under a special permit or withdraws previously granted authority to operate under a special permit, transportation capacity made available to the market and our transportation revenues and cash flows would be reduced.

For additional information, see Item 1 – *Business – Expansion Projects* and Item 1A – *Risk Factors – A portion of the expected maximum daily capacity of our pipeline expansion projects is subject to our obtaining and maintaining authority from PHMSA to operate under higher operating pressures.*

Credit and Capital Markets Disruption

Current economic conditions have made it difficult for companies to obtain funding in either the debt or equity markets. The current constraints in the capital markets may affect our ability to obtain funding through new borrowings or

the issuance of equity in the public markets. In addition, we expect that, to the extent we are successful in arranging new debt financing, we will incur increased costs associated with these debt financings. As of December 31, 2008, in addition to \$312.7 million of cash on hand and short-term investments, we had available capacity under our credit facility of \$161.5 million which we subsequently fully borrowed against. We expect to utilize these resources, along with cash from operations and proceeds from debt and equity offerings, to fund our growth capital expenditures and working capital needs during 2009. See *Liquidity and Capital Resources – Expansion Capital Expenditures* below for a discussion of our financing plans for our current expansion projects.

Financial Analysis of Operations

We derive our revenues primarily from the interstate transportation and storage of natural gas for third parties. Transportation and storage services are provided under firm and interruptible service agreements. Our operating costs and expenses typically do not vary significantly based upon the amount of gas transported, with the exception of fuel consumed at our compressor stations, which is included in Fuel and gas transportation expenses on our Consolidated Statements of Income. The following analysis discusses our financial results of operations for the years 2008, 2007 and 2006.

2008 Compared with 2007

Our net income for the year ended December 31, 2008 increased \$66.3 million, or 29%, to \$294.0 million compared to \$227.7 million for the year ended December 31, 2007. The primary drivers for the increase were higher revenues from services associated with our expansion projects and gains from the disposition of coal reserves, gas sales associated with our storage expansion and the settlement of a contract claim. The favorable drivers were partly offset by lower PAL revenues due to unfavorable natural gas price spreads and higher depreciation and property tax expense due to an increase in our asset base from expansion. The 2007 period was unfavorably impacted by a \$14.7 million impairment charge related to the Magnolia storage facility.

Operating revenues for the year ended December 31, 2008 increased \$141.6 million, or 22%, to \$784.8 million, compared to \$643.2 million for the year ended December 31, 2007. Gas transportation revenues, excluding fuel, increased \$112.1 million, primarily from our expansion projects and higher no-notice and interruptible services on our existing assets. Fuel revenues increased \$43.9 million due to expansion-related throughput and higher natural gas prices. Gas storage revenues increased \$12.1 million related to an increase in storage capacity associated with our Western Kentucky Storage Expansion. These increases were partially offset by lower PAL revenues of \$26.5 million due to unfavorable natural gas price spreads.

Operating costs and expenses for the year ended December 31, 2008 increased \$61.0 million, or 16%, to \$438.2 million, compared to \$377.2 million for the year ended December 31, 2007. The primary drivers were increased depreciation and other taxes, comprised primarily of property taxes, of \$56.3 million associated with an increase in our asset base, increased fuel costs of \$50.2 million mainly from providing service on our expansion projects and higher natural gas prices and \$5.8 million of third party transportation costs associated with providing customers of our expansion projects access to off-system markets. Administrative and general expenses increased \$5.4 million due to increased outside services mainly due to legal matters, information technology-related expenses from infrastructure improvements, corporate services, higher property insurance from an increase in rates and asset base and a bad debt recovery that favorably impacted the 2007 period. The increases to operating expenses were offset by gains of \$16.5 million from the disposition of coal reserves, \$12.4 million on the sale of gas related to our Western Kentucky Storage Expansion and \$11.2 million from the settlement of a contract claim. Additionally, in the fourth quarter 2008, we changed our employee paid time-off benefits, resulting in a reduction in operation and maintenance expenses of \$4.9 million and a reduction of administrative and general expenses of \$2.3 million. The 2007 period was unfavorably impacted by a \$14.7 million impairment charge related to our Magnolia storage project.

Total other deductions increased by \$14.1 million, or 38%, to \$51.6 million for the year ended December 31, 2008, compared to \$37.5 million for the 2007 period, primarily as a result of \$18.6 million of decreased interest income due to lower average cash balances available for investment, partly offset by a \$3.3 million reduction in interest expense from higher capitalized interest associated with our expansion projects.

2007 Compared with 2006

Our net income for the year ended December 31, 2007 increased \$30.1 million, or 15%, to \$227.7 million compared to \$197.6 million for the year ended December 31, 2006. The primary drivers for the increase were higher revenues from strong demand for firm transportation services, including pipeline system expansion and related fuel revenues. Higher operating expenses driven by a variety of factors, mainly charges for impairment and remediation costs associated with certain assets, increased fuel and higher depreciation and amortization were substantially offset by higher interest income. The 2007 results were also favorably impacted by a gain on the sale of gas associated with a storage expansion project, which was accounted for as a reduction of operating expenses.

Total operating revenues increased \$35.6 million, or 6%, to \$643.2 million for the year ended December 31, 2007, compared to \$607.6 million for the year ended December 31, 2006. Gas transportation revenues increased \$23.4 million due to higher firm transportation rates, including \$8.9 million from new contracts associated with a pipeline expansion which was in service for all of 2007. Fuel revenues increased \$11.9 million due to increased retained volumes from higher system utilization including amounts associated with pipeline expansion.

Operating costs and expenses increased \$23.5 million, or 7%, to \$377.2 million for the year ended December 31, 2007, compared to \$353.7 million for the year ended December 31, 2006. The primary drivers were impairment charges of \$14.7 million related to the Magnolia storage facility and \$4.5 million associated with offshore pipeline assets in the South Timbalier Bay area, and an \$11.0 million increase in depreciation and other taxes associated with an increase in our asset base from expansion. Other increases included fuel costs of \$6.9 million due to an increase in gas usage, a \$4.8 million charge related to re-covering offshore assets and a \$3.8 million charge related to the termination of an agreement with a construction contractor on the Southeast Expansion project. These increases were offset by a \$22.0 million gain on the sale of gas associated with the Western Kentucky Storage Expansion project which was reported in Net gain on disposal of operating assets and related contracts.

Total other deductions declined by \$18.6 million, or 33%, to \$37.5 million for the year ended December 31, 2007, compared to \$56.1 million for the year ended December 31, 2006. The reduction was primarily due to an increase in interest income of \$17.3 million as a result of higher levels of invested cash which we accumulated through sales of our debt and equity to finance the cost of our expansion projects.

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 and sales of limited partner units. Our operating subsidiaries use funds 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 its revolving credit facility discussed below, to service its outstanding indebtedness and, when available, 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.

Our operating subsidiaries participate in an intercompany cash management program 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.

Beginning in 2007 and continuing in 2008, the capital markets have been impacted by macroeconomic, liquidity, credit and recessionary concerns. During this period, we have continued to have access to the majority of our credit facility to fund our short-term liquidity needs. In 2008, we issued common units and class B units and received additional contributions from our general partner. We also received net proceeds of \$247.2 million from the issuance of long-term debt in March 2008. See discussion below under *Equity and Debt Financing*. Our ability to continue to access capital markets for debt and equity financing under reasonable terms depends on our financial condition, credit ratings and market conditions. We anticipate that our existing capital resources, ability to obtain financing and cash flow generated from future operations will enable us to maintain our current level of operations and our planned operations, including capital expenditures, for 2009.

Maintenance Capital Expenditures

Maintenance capital expenditures were \$50.5 million, \$47.1 million and \$41.7 million in 2008, 2007 and 2006. We expect to fund our 2009 maintenance capital expenditures of approximately \$67.8 million from our operating cash flows.

Expansion Capital Expenditures

We are currently engaged in several pipeline expansion projects, described in Item I, *Our Business – Expansion Projects*, of this Report and expect the estimated total cost of these projects to be as follows (in millions):

| | Estimated Total Cost (1) | Cash Invested through December 31, 2008 |
|--------------------------------------|---|--|
| Southeast Expansion | \$ 775 | \$ 707.3 |
| Gulf Crossing Project | 1,800 | 1,403.5 |
| Fayetteville and Greenville Laterals | 1,290 | 684.2 |
| Total | <u>\$ 3,865</u> | <u>\$ 2,795.0</u> |

- (1) Our cost estimates are based on internally developed financial models and timelines. 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.

Based upon our current cost estimates, we expect to incur capital expenditures of approximately \$1.0 billion in 2009 and 2010 to complete our pipeline expansion projects. The majority of the expenditures are expected to occur during the first half of 2009, with the remaining costs associated with the construction of additional compression facilities for the Gulf Crossing Project and the Fayetteville and Greenville Laterals to be incurred in the latter half of 2009 and into 2010.

We are also engaged in the Western Kentucky Storage Expansion project. The cost of this project is expected to be approximately \$87.7 million. Through December 31, 2008, we spent \$48.0 million related to this project.

Our cost and timing estimates for these projects are subject to a variety of risks and uncertainties, including obtaining regulatory approvals; adverse weather conditions; delays in obtaining key materials; shortages of qualified labor and escalating costs of labor and materials. As the announced expansion projects move toward completion, the risks and uncertainties associated with the expansion projects are decreasing. However, certain risks remain, primarily involving river crossings and receipt of regulatory authority to operate the pipelines at higher operating pressures.

We have financed our expansion capital costs through the issuance of equity and debt, including sales of debt by us and our subsidiaries, borrowings under our revolving credit facility and available operating cash flow in excess of our operating needs. We anticipate we will need to finance an additional \$500.0 million to complete our expansion projects. Our largest unitholder, Loews, has advised us that it is willing to provide the capital we need to complete the expansion projects to the extent the public markets remain unavailable on acceptable terms. We have not committed to any transaction at this time, however, and any additional financing provided by Loews would be subject to review and approval, as to fairness, by our independent Conflicts Committee. Item 1A, *Risk Factors*, contains more information regarding risks associated with our expansion projects and the related financing.

Equity and Debt Financing

In 2008, we received net cash proceeds of approximately \$1.7 billion from the following equity and debt issuances which proceeds were used to fund a portion of the costs of our ongoing expansion projects and to repay amounts borrowed under our revolving credit facility (in millions, except issue price):

| Month of Issuance | Net Cash Proceeds Received | Number of Units | Issue Price | Type of Issuance |
|-------------------|----------------------------|-----------------|-------------|--|
| October | \$ 500.0 (a) | 21.2 | \$ 23.13 | Private placement of common units to BPHC |
| June | 700.0 (b) | 22.9 | 30.00 | Private placement of class B units to BPHC |
| June | 248.8 (c) | 10.0 | 25.30 | Public offering of common units |
| March | 247.2 | N/A | N/A | Public offering of debt securities |

- (a) Includes a \$10.0 million contribution received from our general partner to maintain its 2% general partner interest.
- (b) Includes a \$14.0 million contribution received from our general partner to maintain its 2% general partner interest.
- (c) Includes a \$5.2 million contribution received from our general partner to maintain its 2% general partner interest.

We also borrowed under our revolving credit facility, to the extent necessary, to finance our expansion projects. As discussed in *Expansion Capital Expenditures* we have a committed sponsor in Loews who has agreed to finance up to the remaining amount necessary to complete our expansion projects to the extent that the capital markets are not available on acceptable terms. We do not have an immediate need to refinance any of our long-term debt, including borrowings under our revolving credit facility, as the earliest maturity date of such indebtedness is in 2012. We believe that our cash flow from operations will be sufficient to support our ongoing operations and maintenance capital requirements.

Credit Facility

We maintain a revolving credit facility which has aggregate lending commitments of \$1.0 billion, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. A financial institution which has a \$50.0 million commitment under the revolving credit facility filed for bankruptcy protection in the third quarter 2008 and has not funded its portion of our borrowing requests since that time. Interest on amounts drawn under the credit facility is payable at a floating rate equal to an applicable spread per annum over the London Interbank Offered Rate or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. The revolving credit facility has a maturity date of June 29, 2012.

As of December 31, 2008, we had \$792.0 million of loans outstanding under the revolving credit facility with a weighted-average interest rate on the borrowings of 3.43% and had no letters of credit issued. We were in compliance with all covenant requirements under our credit facility at December 31, 2008. Subsequent to December 31, 2008, we borrowed all of the remaining unfunded commitments under the credit facility (excluding the unfunded commitment of the bankrupt lender noted above) which increased borrowings to \$953.5 million.

Our revolving credit facility contains customary negative covenants, including, among others, limitations on the payment of cash dividends and other restricted payments, the incurrence of additional debt, sale-leaseback transactions and transactions with our affiliates. The facility also contains a financial covenant that requires us and our subsidiaries to maintain a ratio of total consolidated debt to consolidated earnings before income taxes, depreciation and amortization (as defined in the credit agreement), measured for the preceding twelve months, of not more than five to one. Although we do not believe that these covenants have had, or will have, a material impact on our business and financing activities or our ability to obtain the financing to maintain operations and continue our capital investments, they could restrict us in some circumstances as stated in Item 1A, *Risk Factors*. In particular, maintaining compliance with the financial covenant may limit our ability to incur additional indebtedness to finance our growth projects, which could limit our growth opportunities or require the issuance of more equity securities by us than previously anticipated.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations under firm commitments as of December 31, 2008, by period (in millions):

| | Total | Less than 1 Year | 1-3 Years | 4-5 Years | More than 5 Years |
|---|-------------------|-----------------------------|------------------|-------------------|------------------------------|
| Principal payments on long-term debt (1) \$ | 2,902.0 | - | - | \$ 1,267.0 | \$ 1,635.0 |
| Interest on long-term debt (2) | 921.9 | \$ 117.5 | \$ 234.9 | 214.4 | 355.1 |
| Capital commitments (3) | 198.7 | 195.8 | 2.9 | - | - |
| Pipeline capacity agreements (4) | 102.8 | 12.6 | 22.5 | 20.5 | 47.2 |
| Operating lease commitments | 25.7 | 3.3 | 6.2 | 6.0 | 10.2 |
| Total | \$ 4,151.1 | \$ 329.2 | \$ 266.5 | \$ 1,507.9 | \$ 2,047.5 |

- (1) This includes our senior unsecured notes, having maturity dates from 2012 to 2027 and \$792.0 million of loans outstanding under our revolving credit facility, having a maturity date of June 29, 2012.
- (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. Based on a 3.43% weighted-average interest rate on amounts outstanding under our revolving credit facility as of December 31, 2008, \$27.2 million, \$54.3 million and \$13.6 million would be due under the credit facility in less than one year, 1-3 years, and 4-5 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, 2008. The amounts shown do not reflect commitments we have made after December 31, 2008. For information on these projects, please read *Expansion Capital Expenditures*.
- (4) The amounts shown are associated with various pipeline capacity agreements on third-party pipelines that allow our operating subsidiaries to transport gas to off-system markets on behalf of our customers.

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 2009, we expect to fund approximately \$5.0 million to the Texas Gas pension plan.

Cash and Cash Equivalents and Short-term Investments

At December 31, 2008, we had \$137.7 million of cash and cash equivalents invested primarily in Treasury funds and \$175.0 million of short-term investments. In December 2008, we began investing a portion of our cash and cash equivalents in U.S. Government securities, primarily Treasury notes, under repurchase agreements. Generally, we have engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. Pursuant to the master repurchase agreements, we take actual possession of the purchased securities. In the event of default by the counterparty under the agreement, the repurchase would be deemed immediately to occur and we would be entitled to sell the securities in the open market, or give the counterparty credit based on the market price on such date, and apply the proceeds (or deemed proceeds) to the aggregate unpaid repurchase amounts and any other amounts owing by the counterparty. Note 14 in Item 8 of this Report contains more information about our short-term investments.

Changes in cash flow from operating activities

Net cash provided by operating activities increased \$68.6 million to \$350.3 million for the year ended December 31, 2008, compared to \$281.7 million for the comparable 2007 period, primarily due to a \$78.8 million increase in cash from the change in net income, excluding non-cash items such as depreciation and amortization and the recognition of income previously deferred. This increase was offset by an \$11.0 million decrease in cash due to the settlement of derivatives.

Changes in cash flow from investing activities

Net cash used in investing activities increased \$1,577.1 million to \$2,757.4 million for the year ended December 31, 2008, compared to \$1,180.3 million for the comparable 2007 period, primarily due to a \$1,442.7 million increase in capital expenditures related to our expansion projects and a \$175.0 million purchase of short-term investments in 2008. These increases in the use of cash from investing activities were offset by \$35.1 million in net proceeds from the sale of gas related to our storage expansion projects and the sale of an investment in coal reserves.

Changes in cash flow from financing activities

Net cash provided by financing activities increased \$1,410.6 million to \$2,227.5 million for the year ended December 31, 2008, compared to \$816.9 million for the comparable 2007 period. An increase of \$922.2 million resulted from net proceeds received from the issuance of common and class B units, including related general partner capital contributions. Net proceeds from the issuance of long-term debt and borrowings under our revolving credit facility increased \$543.9 million. These increases in cash from financing activities were partially offset by a \$55.5 million increase in distributions to our partners.

Impact of Inflation

We have experienced increased costs in recent years due to the effect of inflation on the cost of labor, benefits, materials and supplies, and property, plant and equipment (PPE). A portion of the increased labor and materials and supplies costs have directly affected income through increased operating costs and depreciation expense. 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 and materials and supplies 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, 2008, 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 Policies

Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time the financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities and our disclosure of contingent assets and liabilities in our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with third parties and other methods we consider reasonable. Nevertheless, actual results may differ significantly from our 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.

Regulation

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. At December 31, 2008 and 2007, there were no liabilities for any open rate case recorded on our Consolidated Balance Sheets. Currently, neither Gulf South nor Texas Gas is involved in an open general rate case, however Gulf Crossing will either have to file a rate case or justify its initial firm transportation rates within three years after the pipeline is fully placed in service.

Our subsidiaries are regulated by FERC. SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*, requires certain rate-regulated entities to account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. SFAS No. 71 is applicable to operations of our Texas Gas subsidiary which record certain costs and benefits as regulatory assets and liabilities, respectively, in order to

provide for recovery from or refund to customers in future periods. The provisions of SFAS No. 71 are not applicable to operations associated with the Texas Gas Fayetteville and Greenville Laterals project and Phase III of the Western Kentucky Storage Expansion project due to the regulatory treatment and contractual rates associated with the projects. The provisions of SFAS No. 71 are not applicable to Gulf Crossing due to discounts under negotiated rate agreements, or Gulf South because competition in the market areas of Gulf South has resulted in discounts from the maximum allowable cost-based rates being granted to customers and certain services provided by Gulf South are priced using market-based rates, such that the application of the standard would not be appropriate.

We monitor the regulatory and competitive environment in which we operate to determine that any 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 under SFAS No. 71, that portion which was not recoverable would be written off, net of any regulatory liabilities. Note 6 in Item 8 of this Report contains more information regarding our regulatory assets and liabilities.

In the course of providing transportation and storage services to customers, the pipelines may receive different quantities of gas from shippers and operators than the quantities delivered by the pipelines 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 through the receipt or delivery of gas in the future or with cash. 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 SFAS No. 71 is not applicable and are valued at the historical value of gas in storage for operations where SFAS No. 71 is applicable, consistent with the regulatory treatment and the settlement history.

Environmental Liabilities

Our environmental liabilities are based on management's best estimate of the undiscounted future obligation 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. At December 31, 2008, we had accrued approximately \$16.8 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 Environmental Protection Agency, 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 total estimated environmental costs.

Impairment of Long-Lived Assets

We periodically evaluate whether the carrying value of long-lived assets has been impaired when circumstances indicate the carrying value of those assets may not be recoverable in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. This evaluation is based on undiscounted cash flow projections expected to be realized over the remaining useful life of the asset. 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 value is not recoverable, the impairment loss is measured as the excess of the asset's carrying value over its fair value.

In 2008, we completed a review of our non-contiguous offshore assets and provided notice to the other interest holders of our intent to discontinue any use of our portion of the capacity available to us as a result of our investment in the assets. As a result, we reviewed the assets for recoverability and recorded an impairment charge of approximately \$3.0 million representing the book value of the assets.

We were developing a salt dome storage cavern near Napoleonville, Louisiana. Operational tests, which were completed in July 2007, indicated that due to geological and other anomalies that could not be corrected, we would be unable to place the cavern in service as expected. As a result, we elected to abandon that cavern and are exploring the possibility of securing a new site on which a new cavern could be developed. In accordance with the requirements of SFAS No. 144, the carrying value of the cavern and related facilities was tested for recoverability. In the second quarter 2007, we recognized an impairment charge to earnings of approximately \$14.7 million, representing the carrying value of the cavern, the fair value of which was determined to be zero based on discounted expected future cash flows. We expect to use the other assets associated with the project, which include pipeline, compressors, and other equipment and facilities, in conjunction with a replacement storage cavern to be developed. If we determine in the future that the assets cannot be used

in conjunction with a new cavern or a new cavern cannot be secured in the same area, we may be required to record an additional impairment charge at the time that determination is made. Additional costs to abandon the impaired cavern may be incurred due to regulatory or contractual obligations; however, the amounts are inestimable at this time.

Goodwill

As of December 31, 2008, we had \$163.5 million of goodwill recorded as an asset on our Consolidated Balance Sheets. SFAS No. 142, *Goodwill and Other Intangible Assets*, requires the evaluation of goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired.

An impairment test performed in accordance with SFAS No. 142 requires that a reporting unit's fair value be estimated. We used a discounted cash flow model to estimate the fair value of the reporting unit, and that estimated fair value was compared to the carrying amount, including goodwill. The estimated fair value was in excess of the carrying amount at December 31, 2008, and accordingly no impairment was recognized. Judgments and assumptions were used in management's estimate of discounted future cash flows used to calculate the fair value of the reporting unit, including our five-year financial plan operating results, the long-term outlook for growth in natural gas demand in the U.S. and systematic or diversifiable risk used in the calculation of the applied discount rate under the capital asset pricing model. The use of alternate judgments and/or assumptions could result in the recognition of an impairment charge in the financial statements.

Defined Benefit Plans

We are required to make a significant number of assumptions in order to estimate the 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 pension 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 pension obligations and pension expense.

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. The Moody's Aa Corporate Bond Index is 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 developed by the plans' actuaries and 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. or a rating of AA or better by Standard & Poor's.

Further information on our pension and postretirement benefit obligations is included in Note 10 in Item 8 of this Report.

Recent Accounting Pronouncements

For a discussion regarding recently issued accounting pronouncements or accounting pronouncements adopted in 2008, please read Notes 2, 9 and 18 in Item 8 of this Report.

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 its subsidiaries, are also forward-looking statements.

Forward-looking statements are based on current expectations and projections about future events and 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:

- We may not complete projects, including growth or expansion 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 completion, timing, cost, scope and future financial performance of our expansion projects could differ materially from our expectations due to availability of contractors or equipment, ground conditions, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages and numerous other factors beyond our control.
- Global financial markets and economic conditions have been, and continue to be, experiencing extraordinary disruption and volatility following adverse changes in global capital markets. The cost of raising money in the debt and equity capital markets and commercial credit markets has increased substantially while the availability of funds from those markets has diminished significantly.
- A portion of the transportation capacity on each of our expansion project pipelines that we expect will ultimately be available is contingent upon our receipt of authority to operate each of these pipelines at higher operating pressures under a special permit issued by PHMSA. To the extent that PHMSA does not grant us authority to operate any of our expansion pipelines under a special permit or withdraws previously granted authority to operate under a special permit, transportation capacity made available to the market and transportation revenues received in the future could be reduced.
- Our FERC gas tariffs only allow us to require limited credit support in the event that our transportation customers are unable to pay for our services. If any of our significant customers have credit or financial problems which result in a delay or failure to pay for services provided by us, or contracted for with us, or repay the gas they owe us, it could adversely affect our business, financial condition and results of operations.
- The gas transmission and storage operations of our subsidiaries are subject to rate-making policies and actions by FERC or customers that could have an adverse impact on the services we offer and the rates we charge and our ability to recover the full cost of operating our pipelines, including earning a reasonable return.
- We are subject to laws and regulations relating to the environment and pipeline operations which may expose us to significant costs, liabilities and loss of revenues. Any changes in such regulations or their application generally or through enforcement actions could adversely affect our business, financial condition and results of operations.
- Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.
- The cost of insuring our assets may increase dramatically.
- Because of the natural decline in gas production connected to our system, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business, financial condition and results of operations.
- We may not be able to maintain or replace expiring gas transportation and storage contracts at favorable rates.
- Significant changes in natural gas prices could affect supply and demand, reducing system throughput and adversely affecting our revenues.

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 of this Report 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.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Interest rate risk:

With the exception of our revolving credit facility, for which the interest rate is reset each quarter, 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 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):

| | 2008 | 2007 |
|--|------------|------------|
| Carrying value of debt | \$ 2,097.4 | \$ 1,847.9 |
| Fair value of debt | \$ 1,863.3 | \$ 1,834.2 |
| 100 basis point increase in interest rates and resulting debt decrease | \$ 117.1 | \$ 118.8 |
| 100 basis point decrease in interest rates and resulting debt increase | \$ 126.1 | \$ 129.3 |
| Weighted-average interest rate | 5.89% | 5.82% |

At December 31, 2008, we had \$792.0 million outstanding under our revolving credit agreement at a weighted-average interest rate of 3.43%, which rate is reset each quarter. A 1% increase or decrease in interest rates would increase or reduce our cash payments for interest on the credit facility by \$8.0 million on an annual basis. No amounts were borrowed under our revolving credit facility at December 31, 2007.

At December 31, 2008, \$137.7 million of our undistributed cash, shown on the balance sheets as Cash and cash equivalents, was invested in Treasury fund accounts and \$175.0 million was invested in U.S. Treasury notes under repurchase agreements and shown as Short-term investments. At December 31, 2007, all of our cash was 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. Since our investments under repurchase agreements are liquidated the following day at an established price, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the fair market value of our short-term investments.

Commodity risk:

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2008 and 2007, approximately \$0.2 million and \$16.3 million of gas stored underground, which we own and carry as current Gas stored underground, was available for sale and exposed to commodity price risk. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas. Our pipelines do not take title to the natural gas which they transport and store in rendering traditional firm and interruptible storage services, therefore they do not assume the related natural gas commodity price risk associated with that gas.

The derivatives related to the sale of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The effective component of related gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive (loss) income. The deferred gains and losses are recognized in earnings when the anticipated transactions affect earnings. Generally, for gas sales and retained fuel, any gains and losses on the related derivatives would be recognized in Operating Revenues.

Credit risk:

We are exposed to credit risk relating to the risk of loss resulting from the nonperformance by a customer of its contractual obligations. We have established credit policies in the pipeline tariffs which are intended to minimize credit risk in accordance with FERC policies and actively monitor this portion of our business. 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 no-notice services. Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the gas they owe to us, this could have a material adverse effect on our financial condition, results of operations and cash flows.

As of December 31, 2008, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 34.4 trillion British thermal units (TBtu). Assuming an average market price during December 2008 of \$5.85 per million British thermal units (MMBtu), the market value of this gas at December 31, 2008, would have been approximately \$201.2 million. As of December 31, 2007, the amount of gas loaned out by our subsidiaries or owed to our subsidiaries due to gas imbalances was approximately 15.2 TBtu. Assuming an average market price during December 2007 of \$7.13 per MMBtu, the market value of this gas at December 31, 2007, would have been approximately \$108.4 million.

More than 85% of our revenues are derived from gas marketers, LDCs and producers, the majority of which have investment grade ratings. 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 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 associated with our expansion projects, we have included contractual provisions that require additional credit support should the credit ratings of those customers fall below investment grade.

After completion of our expansion projects, producers will comprise a larger portion of our revenues, both in aggregate as a group and separately. We expect producers as a group to contribute a more significant portion of our future revenues and one producer to represent over 10% of our total revenues. Historically producers have had lower credit ratings than LDCs and LDC-sponsored marketing companies, therefore the expected change in our customer base could result in higher total credit risk. We will continue to actively monitor the credit risks associated with our customer base.

Market risk:

Our primary exposure to market risk occurs at the time our existing transportation and storage contracts expire and are subject to termination or renegotiation. In addition, we have market risk exposure if one of our transportation or storage customers defaults on a service agreement and we are unable to resell the capacity at the same or higher rate. As a result of competition in the industry, we actively monitor future expiration dates associated with our contract portfolio. As of December 31, 2008, approximately 17% of the firm contract load on our pipeline systems, excluding agreements related to the expansion projects not yet in service, was due to expire on or before December 31, 2009. As of December 31, 2007, the firm contract load due to expire within one year was 25%. Many of the contracts comprising the 25% were renewed or remarketed at favorable terms and for extended terms, increasing our weighted-average contract term.

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, 2008 and 2007, and the related consolidated statements of income, changes in partners' capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2008. Our audits also included the financial statement schedule included in the Index at Item 15. These financial statements and financial statement schedule are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule 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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

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, 2008, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2009 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Houston, Texas
February 24, 2009

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

(Millions)

| ASSETS | December 31, | |
|--|-------------------|-------------------|
| | 2008 | 2007 |
| Current Assets: | | |
| Cash and cash equivalents | \$ 137.7 | \$ 317.3 |
| Short-term investments | 175.0 | - |
| Receivables: | | |
| Trade, net | 67.3 | 60.7 |
| Other | 18.0 | 12.7 |
| Gas Receivables: | | |
| Transportation and exchange | 13.5 | 12.5 |
| Storage | - | 1.3 |
| Inventories | 2.6 | 16.6 |
| Costs recoverable from customers | 5.4 | 6.3 |
| Gas stored underground | 0.2 | 16.3 |
| Prepayments | 17.3 | 7.9 |
| Other current assets | 14.8 | 4.0 |
| Total current assets | <u>451.8</u> | <u>455.6</u> |
| Property, Plant and Equipment: | | |
| Natural gas transmission plant | 3,871.0 | 2,392.5 |
| Other natural gas plant | 215.2 | 224.0 |
| | <u>4,086.2</u> | <u>2,616.5</u> |
| Less—accumulated depreciation and amortization | 382.4 | 262.5 |
| | <u>3,703.8</u> | <u>2,354.0</u> |
| Construction work in progress | 2,196.4 | 951.4 |
| | <u>5,900.2</u> | <u>3,305.4</u> |
| Property, plant and equipment, net | | |
| Other Assets: | | |
| Goodwill | 163.5 | 163.5 |
| Gas stored underground | 124.8 | 137.1 |
| Costs recoverable from customers | 15.4 | 15.9 |
| Other | 65.9 | 44.5 |
| Total other assets | <u>369.6</u> | <u>361.0</u> |
| Total Assets | <u>\$ 6,721.6</u> | <u>\$ 4,122.0</u> |

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS

(Millions)

| LIABILITIES AND PARTNERS' CAPITAL | December 31, | |
|--|---------------------|-------------------|
| | 2008 | 2007 |
| Current Liabilities: | | |
| Payables: | | |
| Trade | \$ 216.4 | \$ 190.6 |
| Affiliates | 1.8 | 1.3 |
| Other | 7.4 | 5.1 |
| Gas Payables: | | |
| Transportation and exchange | 11.6 | 17.8 |
| Accrued taxes, other | 35.2 | 20.2 |
| Accrued interest | 40.1 | 30.8 |
| Accrued payroll and employee benefits | 16.3 | 22.3 |
| Construction retainage | 76.3 | 32.2 |
| Deferred income | 1.8 | 7.2 |
| Other current liabilities | 27.1 | 26.5 |
| Total current liabilities | <u>434.0</u> | <u>354.0</u> |
| Long –Term Debt | <u>2,889.4</u> | <u>1,847.9</u> |
| Other Liabilities and Deferred Credits: | | |
| Pension liability | 35.7 | 17.2 |
| Asset retirement obligation | 18.0 | 16.1 |
| Provision for other asset retirement | 45.6 | 42.4 |
| Payable to affiliate | 20.6 | - |
| Other | 33.3 | 41.4 |
| Total other liabilities and deferred credits | <u>153.2</u> | <u>117.1</u> |
| Commitments and Contingencies | | |
| Partners' Capital: | | |
| Common units – 154.9 and 90.7 common units issued and outstanding as of December 31, 2008 and 2007 | 2,504.8 | 1,473.9 |
| Class B units – 22.9 units issued and outstanding as of December 31, 2008 | 692.8 | - |
| Subordinated units –33.1 units issued and outstanding as of December 31, 2007 | - | 291.7 |
| General partner | 62.9 | 33.2 |
| Accumulated other comprehensive (loss) income, net of tax | (15.5) | 4.2 |
| Total partners' capital | <u>3,245.0</u> | <u>1,803.0</u> |
| Total Liabilities and Partners' Capital | <u>\$ 6,721.6</u> | <u>\$ 4,122.0</u> |

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, | | |
|---|--|-------------|-------------|
| | 2008 | 2007 | 2006 |
| Operating Revenues: | | | |
| Gas transportation | \$ 698.2 | \$ 529.7 | \$ 508.2 |
| Parking and lending | 16.3 | 42.8 | 49.2 |
| Gas storage | 51.5 | 39.4 | 32.4 |
| Other | 18.8 | 31.3 | 17.8 |
| Total operating revenues | 784.8 | 643.2 | 607.6 |
| Operating Costs and Expenses: | | | |
| Fuel and gas transportation | 102.4 | 46.4 | 39.9 |
| Operation and maintenance | 119.9 | 127.4 | 121.4 |
| Administrative and general | 106.0 | 97.0 | 97.3 |
| Depreciation and amortization | 124.8 | 81.8 | 75.8 |
| Contract settlement gain | (11.2) | - | - |
| Asset impairment | 3.0 | 19.2 | - |
| Net gain on disposal of operating assets and related contracts | (49.2) | (23.8) | (4.8) |
| Taxes other than income taxes | 42.5 | 29.2 | 24.1 |
| Total operating costs and expenses | 438.2 | 377.2 | 353.7 |
| Operating income | 346.6 | 266.0 | 253.9 |
| Other Deductions (Income): | | | |
| Interest expense | 57.7 | 61.0 | 62.1 |
| Interest income | (2.9) | (21.5) | (4.2) |
| Miscellaneous other income, net | (3.2) | (2.0) | (1.8) |
| Total other deductions | 51.6 | 37.5 | 56.1 |
| Income before income taxes | 295.0 | 228.5 | 197.8 |
| Income taxes | 1.0 | 0.8 | 0.2 |
| Net income | \$ 294.0 | \$ 227.7 | \$ 197.6 |
| Calculation of limited partners' interest in Net income: | | | |
| | For the Year Ended December 31, | | |
| | 2008 | 2007 | 2006 |
| Net income | \$ 294.0 | \$ 227.7 | \$ 197.6 |
| Less general partner's interest in Net income | 13.3 | 7.0 | 4.0 |
| Limited partners' interest in Net income | \$ 280.7 | \$ 220.7 | \$ 193.6 |
| Basic and diluted net income per limited partner unit: | | | |
| Common units | \$ 1.98 | \$ 1.87 | \$ 1.85 |
| Class B units | \$ 0.60 | \$ - | \$ - |
| Subordinated units (a) | \$ 1.98 | \$ 1.87 | \$ 1.85 |
| Cash distribution to common and subordinated unitholders (a) | \$ 1.87 | \$ 1.74 | \$ 1.32 |
| Cash distribution to class B units (b) | \$ 0.30 | \$ - | \$ - |
| Weighted-average number of limited partners units outstanding: | | | |
| Common units (a) | 104.2 | 82.5 | 69.0 |
| Class B units (b) | 22.9 | - | - |
| Subordinated units (a) | 28.7 | 33.1 | 33.1 |

(a) All of the 33.1 million subordinated units converted to common units on a one-for-one basis in November 2008.

(b) The number of class B units shown is weighted from July 1, 2008, which is the date they became eligible to participate in earnings. The class B units do not participate in quarterly distributions above \$0.30 per unit.

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, | | |
|--|--|------------------|-----------------|
| | 2008 | 2007 | 2006 |
| OPERATING ACTIVITIES: | | | |
| Net income | \$ 294.0 | \$ 227.7 | \$ 197.6 |
| Adjustments to reconcile to cash provided by operations: | | | |
| Depreciation and amortization | 124.8 | 81.8 | 75.8 |
| Amortization of deferred costs | 9.0 | 8.3 | 8.7 |
| Amortization of acquired executory contracts | (0.2) | (1.1) | (4.0) |
| Asset impairment | 3.0 | 19.2 | - |
| Net gain on disposal of operating assets and related contracts | (49.2) | (23.8) | (4.8) |
| Changes in operating assets and liabilities: | | | |
| Trade and other receivables | (16.6) | (4.1) | (0.4) |
| Gas receivables and storage assets | 61.5 | 40.7 | 63.5 |
| Costs recoverable from customers | 0.9 | 3.6 | (4.0) |
| Inventories | (8.8) | (2.5) | 1.8 |
| Other assets | (30.5) | (13.3) | (17.4) |
| Trade and other payables | 9.5 | (15.9) | 9.1 |
| Gas payables | (50.4) | (53.2) | (87.2) |
| Accrued liabilities | 7.0 | 12.9 | (8.1) |
| Other liabilities | (3.7) | 1.4 | 24.9 |
| Net cash provided by operating activities | <u>350.3</u> | <u>281.7</u> | <u>255.5</u> |
| INVESTING ACTIVITIES: | | | |
| Capital expenditures | (2,652.5) | (1,209.8) | (200.3) |
| Proceeds from sale of operating assets, net | 63.8 | 28.7 | 3.6 |
| Proceeds from insurance reimbursements and other recoveries | 4.7 | 1.7 | 5.9 |
| Advances to affiliates, net | 1.6 | (0.9) | (0.7) |
| Purchases of short-term investments | <u>(175.0)</u> | <u>-</u> | <u>-</u> |
| Net cash used in investing activities | <u>(2,757.4)</u> | <u>(1,180.3)</u> | <u>(191.5)</u> |
| FINANCING ACTIVITIES: | | | |
| Payments of notes payable | - | - | (42.1) |
| Proceeds from long-term debt, net of issuance costs | 247.2 | 495.3 | 338.3 |
| Proceeds from borrowings on revolving credit agreement | 1,484.0 | - | - |
| Repayment of borrowings on revolving credit agreement | (692.0) | - | (90.0) |
| Distributions | (260.5) | (205.0) | (136.4) |
| Proceeds from sale of common units, net of related transaction costs | 733.6 | 515.9 | 195.2 |
| Proceeds from sale of class B units | 686.0 | - | - |
| Capital contribution from general partner | <u>29.2</u> | <u>10.7</u> | <u>4.2</u> |
| Net cash provided by financing activities | <u>2,227.5</u> | <u>816.9</u> | <u>269.2</u> |
| (Decrease) increase in cash and cash equivalents | <u>(179.6)</u> | <u>(81.7)</u> | <u>333.2</u> |
| Cash and cash equivalents at beginning of period | <u>317.3</u> | <u>399.0</u> | <u>65.8</u> |
| Cash and cash equivalents at end of period | <u>\$ 137.7</u> | <u>\$ 317.3</u> | <u>\$ 399.0</u> |

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

(Millions)

| | Common Units | Class B Units | Subordinated Units | General Partner | Accumulate d Other Comp (Loss) Income | Total Partners' Capital |
|--|-------------------|------------------|-----------------------|--------------------|---|-------------------------------|
| Balance January 1, 2006 | \$ 705.6 | \$ - | \$ 266.6 | \$ 16.7 | \$ (0.2) | \$ 988.7 |
| Add (deduct): | | | | | | |
| Net income | 131.0 | - | 62.6 | 4.0 | - | 197.6 |
| Distributions paid | (90.0) | - | (43.6) | (2.8) | - | (136.4) |
| Sale of common units, net of related transaction costs (6.9 units) | 195.2 | - | - | - | - | 195.2 |
| Capital contribution from general partner | - | - | - | 4.2 | - | 4.2 |
| Other comprehensive income, net of tax | - | - | - | - | 8.4 | 8.4 |
| Adjustment to initially apply SFAS No. 158, net of tax | - | - | - | - | 14.8 | 14.8 |
| Balance December 31, 2006 | \$ 941.8 | \$ - | \$ 285.6 | \$ 22.1 | \$ 23.0 | \$ 1,272.5 |
| Add (deduct): | | | | | | |
| Net income | 157.2 | - | 63.5 | 7.0 | - | 227.7 |
| Distributions paid | (141.0) | - | (57.4) | (6.6) | - | (205.0) |
| Sale of common units, net of related transaction costs (15.5 units) | 515.9 | - | - | - | - | 515.9 |
| Capital contribution from general partner | - | - | - | 10.7 | - | 10.7 |
| Other comprehensive loss, net of tax | - | - | - | - | (18.8) | (18.8) |
| Balance December 31, 2007 | \$ 1,473.9 | \$ - | \$ 291.7 | \$ 33.2 | \$ 4.2 | \$ 1,803.0 |
| Add (deduct): | | | | | | |
| Net income | 207.4 | 13.7 | 59.7 | 13.2 | - | 294.0 |
| Distributions paid | (179.0) | (6.9) | (61.9) | (12.7) | - | (260.5) |
| Sale of common units, net of related transaction costs (31.2 million common units) | 713.0 | - | - | - | - | 713.0 |
| Sale of class B units (22.9 million class B units) | - | 686.0 | - | - | - | 686.0 |
| Conversion of subordinated units to common units (33.1 million units) | 289.5 | - | (289.5) | - | - | - |
| Capital contribution from general partner | - | - | - | 29.2 | - | 29.2 |
| Other comprehensive loss, net of tax | - | - | - | - | (19.7) | (19.7) |
| Balance December 31, 2008 | <u>\$ 2,504.8</u> | <u>\$ 692.8</u> | <u>\$ -</u> | <u>\$ 62.9</u> | <u>\$ (15.5)</u> | <u>\$ 3,245.0</u> |

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Millions)

| | For the Year Ended December 31, | | |
|--|--|----------|----------|
| | 2008 | 2007 | 2006 |
| Net income | \$ 294.0 | \$ 227.7 | \$ 197.6 |
| Other comprehensive (loss) income: | | | |
| (Loss) gain on cash flow hedges | (16.7) | (9.8) | 19.4 |
| Reclassification adjustment transferred to Net income from cash flow hedges | 24.9 | (7.3) | (11.0) |
| Pension and other postretirement benefits costs | (27.9) | (1.7) | - |
| Total comprehensive income | \$ 274.3 | \$ 208.9 | \$ 206.0 |

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

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 to own and operate the business conducted by our subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines), and its subsidiaries, Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, the operating subsidiaries), and Gulf Crossing Pipeline Company, LLC (Gulf Crossing) a new interstate pipeline, of which the pipeline portion of the assets were placed in service in January and February 2009. As of December 31, 2008, Boardwalk Pipelines Holding Corp. (BPHC) a wholly-owned subsidiary of Loews Corporation (Loews) owns 107.5 million of the Partnership's common units, all 22.9 million of the Partnership's class B 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). The common units, class B units and general partner interest owned by BPHC represent approximately 74% of our equity interests, excluding the IDRs, further described in Note 12. The Partnership is traded under the symbol "BWP" on the New York Stock Exchange (NYSE).

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 (GAAP).

Note 2: Accounting Policies

Principles of Consolidation

The consolidated financial statements include the Partnership's accounts and those of its wholly-owned subsidiaries, Boardwalk Pipelines, Gulf Crossing, Gulf South and Texas Gas, after elimination of intercompany transactions.

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. On an ongoing basis, the Partnership evaluates its estimates, including but not limited to those related to bad debts, materials and supplies obsolescence, investments, goodwill, property and equipment and other long-lived assets, property taxes, pensions and other postretirement and postemployment benefits, share-based and other incentive compensation, contingent liabilities and revenues subject to refund. The Partnership bases its estimates on historical experience and on various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values 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 pipeline systems including integrated storage facilities. This segment consists of interstate natural gas pipeline systems originating in the Gulf Coast area and running north and east through Texas, Louisiana, Arkansas, Mississippi, Alabama, Florida, Tennessee, Kentucky, Indiana, Ohio, Illinois and Oklahoma.

Reclassifications

Certain prior year balances have been reclassified to conform to the current year presentation. Prepayments and Other current assets were separately identified on the Consolidated Balance Sheets due to the materiality of those items at the end of 2008. Fuel and gas transportation expenses were displayed separately from Operation and maintenance expenses on the Consolidated Statements of Income to provide improved transparency related to our Operating Costs and Expenses.

Regulatory Accounting

The operating subsidiaries are regulated by the Federal Energy Regulatory Commission (FERC). Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation*, requires certain rate-regulated entities to account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. SFAS No. 71 is applicable to operations of the Partnership's Texas Gas subsidiary which record certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to customers in future periods. The provisions of SFAS No. 71 are not applicable to operations associated with the Texas Gas Fayetteville and Greenville Laterals project due to rates charged under negotiated rate agreements and Phase III of the Western Kentucky Storage Expansion project due to the regulatory treatment associated with the rates charged under the project. The provisions of SFAS No. 71 are not applicable to the Partnership's Gulf Crossing subsidiary due to discounts under negotiated rate agreements, or Gulf South because competition in its market area has resulted in discounts from the maximum allowable cost-based rates being granted to customers and certain services provided by Gulf South are priced using market-based rates, such that the application of the standard would not be appropriate.

The Partnership monitors the regulatory and competitive environment in which it operates to determine that any 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 under SFAS No. 71, that portion which was not recoverable would be written off, net of any regulatory liabilities. Note 6 contains more information regarding the Partnership's regulatory assets and liabilities.

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, 2008 and 2007.

Cash Management

The operating subsidiaries participate in an intercompany cash management program 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 is recognized on an accrual basis when collection is reasonably assured. The interest rate on intercompany demand notes is London Interbank Offered Rate (LIBOR) plus one percent and is adjusted every three months.

Short-Term Investments

Short-term investments consist of United States (U.S.) Government securities, primarily Treasury notes, under repurchase agreements. Generally, the Partnership has engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. The amount invested under repurchase agreements is stated at fair value. Certain short-term investments, for example those held overnight, result in significant cumulative inflows and outflows of cash. In accordance with SFAS No. 95, *Statement of Cash*

Flows, the Partnership reflects these activities on a net basis in the Investing Activities section of the Consolidated Statements of Cash Flows.

Trade and Other Receivables

Trade and other receivables are stated at their historical carrying amount, net of allowances for doubtful accounts or write-offs. 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

The 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. Certain of these volumes are a result of providing storage services which allow third parties to store their own natural gas in the pipelines' underground facilities.

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 and excess working gas which is available for resale and is valued at the lower of weighted-average cost or market.

The Partnership previously recorded an asset for customer-owned gas held at the Texas Gas storage facilities and an equal and offsetting liability for customer-owned gas held at the Texas Gas storage facilities. At December 31, 2008, the Partnership changed its accounting policy for customer-owned storage gas and no longer records customer-owned gas held at the Texas Gas storage facilities on its Consolidated Balance Sheets. The Partnership desired to conform the accounting of Texas Gas and Gulf South in this regard and believes the new policy is preferable given the lack of title transfer in connection with storage services offered to customers. The Consolidated Balance Sheet for December 31, 2007 has been adjusted to reflect the change in policy resulting in a corresponding reduction of \$35.3 million to Gas stored underground (included in non-current Other Assets) and Gas Payables. The Partnership held for storage approximately 63.8 trillion British thermal units (TBtu) and 67.4 TBtu of gas owned by third parties as of December 31, 2008 and 2007.

In the course of providing transportation and storage services to customers, the pipelines 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 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 SFAS No. 71 is not applicable and are valued at the historical value of gas in storage for operations where SFAS No. 71 is applicable, consistent with the regulatory treatment and the settlement history.

Inventories

Inventories consisting of materials and supplies are carried at average cost, less an allowance for obsolescence. The Partnership has recorded \$2.6 million of inventory expected to be used within one year of the balance sheet date as Current Assets and \$22.9 million was recorded in Other Assets.

Property, Plant and Equipment

Property, plant and equipment (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.

Depreciation of PPE related to operations for which SFAS No. 71 is not applicable 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 SFAS No. 71 is applicable is provided 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 and retirement of PPE for these assets are not recognized in earnings and generally do not impact PPE, net. Note 4 contains more information regarding the Partnership's PPE.

Impairment of Long-lived Assets

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

Repair and Maintenance Costs

The operating subsidiaries account for repair and maintenance costs in accordance with FERC regulations, which is consistent with GAAP. FERC identifies installation, construction and replacement costs that are to be capitalized. All other costs are expensed as incurred.

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

Capitalized interest represents the cost of borrowed funds used to finance construction activities. The Partnership records capitalized interest in connection with construction activities for operations where SFAS No. 71 is not applicable. AFUDC represents the cost of funds, including equity funds, applicable to the regulated natural gas transmission plant under construction as permitted by FERC regulatory practices. The Partnership records AFUDC in connection with the Partnership's operations where SFAS No. 71 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 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, | | |
|--|--|-------------|-------------|
| | 2008 | 2007 | 2006 |
| Capitalized interest and allowance for borrowed funds used during construction | \$ 71.1 | \$ 27.1 | \$ 2.3 |
| Allowance for equity funds used during construction | 0.2 | 3.0 | 1.2 |

Goodwill

SFAS No. 142, *Goodwill and Other Intangible Assets*, requires an evaluation of goodwill for impairment at least annually or more frequently if events and circumstances indicate that the asset might be impaired. The impairment test for goodwill is performed annually at December 31. No impairment of goodwill was recorded during 2008, 2007 or 2006.

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 operating subsidiaries for their services are established through FERC's cost-based rate-making process. Rates charged by the operating subsidiaries may be less than those allowed by FERC. Revenues from the transportation of gas are recognized in the period the service is provided based on contractual terms and the related volumes transported. Revenues from storage services are recognized over the term of the contracts. In connection with certain PAL agreements, cash is received at inception of the service period resulting in the recording of deferred revenues which are recognized in revenues over the period the services are provided. The Partnership had deferred revenues of \$1.8 million and \$7.2 million at December 31, 2008 and 2007. The deferred revenues were related to PAL services to be provided mainly in the subsequent year.

Retained fuel is recognized in revenues at market prices in the month of retention for operations where SFAS No. 71 is not applicable. The related fuel consumed in providing transportation services is recorded in Fuel and gas transportation expenses at market prices in the month consumed. Customers may elect to pay cash for fuel, instead of having fuel retained in-kind. Transportation revenues recognized from retained fuel for the years ended December 31, 2008, 2007 and 2006 were \$134.9 million, \$73.0 million and \$73.2 million.

Under FERC's regulations, certain revenues that the operating subsidiaries collect may be subject to possible refunds to their customers. Accordingly, during a rate case, estimates of rate refund reserves are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2008 and 2007, there were no liabilities for any open rate case recorded on the Consolidated Balance Sheets.

Acquired Executory Contracts

As a result of the acquisition of Gulf South in December 2004, the Partnership recorded certain shipper contracts at fair value. These deferred credits were amortized over the lives of the shipper contracts ranging from three months to three years and were fully amortized at December 31, 2008. Amortization for 2008, 2007 and 2006 was \$0.2 million, \$1.1 million and \$4.0 million.

Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations*, addresses accounting and reporting for existing legal obligations associated with the future retirement of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation 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. Corresponding retirement costs are capitalized as part of the carrying amount of the related long-lived asset and depreciated over the useful life of that asset. Note 5 contains more information regarding the Partnership's asset retirement obligations.

Unit-Based Compensation

The Partnership provides awards of phantom units to certain employees under its Long-Term Incentive Plan and Strategic Long-Term Incentive Plan. Pursuant to SFAS No. 123(R), *Share-Based Payment*, the Partnership

measures the cost of an award issued in exchange for employee services based on the grant-date fair value of the award, which for an award classified as a liability is remeasured each reporting period until settlement. The related compensation expense is recognized over the period the employee is required to provide service in exchange for the award, usually the vesting period. Based on the terms of outstanding awards, to the extent forfeitures of awards occur during a period due to employee terminations, cumulative compensation expense previously recognized is reversed in the period of forfeiture. Note 10 contains additional information regarding the Partnership's unit-based compensation.

Partner Capital Accounts

For purposes of maintaining capital accounts, items of income and loss of the Partnership are allocated among the partners in each taxable year, or portion thereof in accordance with the partnership agreement. Generally, net income for each period is allocated among the partners 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.

Derivative Financial Instruments

Subsidiaries of the Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to various risks, including natural gas commodity and interest rate risk. These hedge contracts are reported at fair value in accordance with SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended. The effective portion of the related unrealized gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of accumulated other comprehensive income. The deferred gains and losses are recognized in earnings when the hedged anticipated transactions affect earnings. Changes in fair value of derivatives that are not designated as cash flow hedges in accordance with SFAS No. 133 are recognized in earnings in the periods that those changes in fair value occur. Note 8 contains more information regarding the Partnership's derivative financial instruments.

In 2008, the Partnership began applying the provisions of FASB Staff Position No. FIN 39-1, *Amendment of FASB Interpretation No. 39*, which permitted a company to change its accounting policy to offset or not offset fair value amounts recognized for derivative instruments under master netting arrangements. The Partnership changed its policy to not offset fair value amounts recognized for its derivatives in its Consolidated Balance Sheets and revised its 2007 presentation to conform to the new policy.

In accordance with the contracts governing the Partnership's derivatives, the counterparty or the Partnership may be required to post cash collateral. As of December 31, 2008, the Partnership held as cash collateral \$5.4 million related to its outstanding derivatives, which was recorded in Other current liabilities. No amounts were received or paid as cash collateral related to the Partnership's outstanding derivatives at December 31, 2007.

Note 3: Commitments and Contingencies

Contractual Release

In December 2008, the Partnership received notice of dissolution of the Alaskan Northwest Natural Gas Transportation Company which was formed in the 1970s and in which Texas Gas was an inactive investor. Along with the notice of dissolution, Texas Gas received a full release from any obligations associated with its equity method investment. As a result, the Partnership reversed the remainder of its liability for estimated obligations associated with the investment and recognized \$3.3 million of income in Miscellaneous other deductions (income), net on the Consolidated Statements of Income. The book value of the investment was zero at December 31, 2008.

Calpine Energy Services (Calpine) Settlement

In 2007, Gulf South and Calpine filed a stipulation and agreement in Calpine's Chapter 11 Bankruptcy proceedings to settle, for approximately \$16.5 million, Gulf South's claim against Calpine related to Calpine's non-

payment under a transportation agreement. The claim, which was approved in 2008, was paid in the form of Calpine stock. In 2007, the Partnership recognized \$4.1 million of revenues related to previously reserved amounts invoiced to Calpine for transportation services previously rendered. In 2008, the Partnership sold the entire claim to a third party and received a cash payment of approximately \$15.3 million. The transfer of the claim was deemed a sale and any recourse related to the sale expired in 2008. As a result, in 2008 the Partnership recorded a net gain of \$11.2 million related to the realization of the unrecognized portion of the claim which was reported as Contract settlement gain on the Consolidated Statements of Income. The matter is considered settled and the Partnership does not expect to receive additional amounts related to the claim.

Impact of Hurricane Rita

In 2005, Hurricane Rita caused physical damage to a portion of the Partnership's assets for which the related remediation work was completed in 2007. In 2008, the Partnership received insurance proceeds of \$5.7 million as final settlement, \$4.7 million of which was applied against a receivable for probable recoveries that was established in 2007 and \$1.0 million of which was recognized as a reduction to Operation and maintenance expense.

Legal Proceedings

Napoleonville Salt Dome Matter

Following the December 2003 accidental release of natural gas from storage in a salt dome cavern operated by Gulf South at the Dow Hydrocarbon and Resources, Inc. (Dow Hydrocarbon), Grand Bayou facility in Belle Rose, Louisiana, several suits were filed, including two that were initially filed as class actions. One of the cases initially filed as a class action was settled in 2008.

A lawsuit entitled *Crystal Aucoin, et al. v. Gulf South Pipeline Company, LP, et al.*, No. 28,157 was filed on February 12, 2004, in the 23rd Judicial District Court for the Parish of Assumption, State of Louisiana. The suit was initially filed as a class action. The defendants at the trial were Gulf South, Dow Chemical Company (Dow Chemical), Dow Hydrocarbon and one of Gulf South's insurers, Oil Insurance Limited (OIL). The plaintiffs voluntarily dismissed their class action allegations on February 2, 2006. Since that time the case has proceeded in the same court as a mass joinder of approximately 1,200 individual claims. The plaintiffs seek damages for alleged inconvenience and emotional distress arising from being forced to drive on a detour around a road closed due to the gas release. A trial was held in August 2008 on damages for a sample group of 23 plaintiffs. In January 2009, the court awarded damages to these plaintiffs of less than \$0.1 million in the aggregate. Gulf South and the other defendants are considering whether to appeal the ruling. Pursuant to an agreement among defendants, Gulf South is responsible for one half of the judgment, subject to final determination of Gulf South's claim for indemnification from Dow Chemical. Any judgment amounts paid would be covered by insurance.

On September 29, 2005, OIL filed suit against Dow Chemical and Dow Hydrocarbon, No. 29,217, in the 23rd Judicial District Court for the Parish of Assumption, State of Louisiana, *Oil Insurance Limited v. Dow Chemical Company, et al.* OIL seeks indemnification from Dow Hydrocarbon for amounts of insurance paid to Gulf South. Dow Hydrocarbon has filed a demand against OIL and a third-party claim against Gulf South. Dow Hydrocarbon's allegations against Gulf South include contractual violations and liability due to negligence and strict liability. Dow Hydrocarbon seeks recovery for property damage, damages arising from the loss of use of certain wells/caverns and damages incurred responding to and remediating the natural gas leak. The case is ongoing and no trial date has been set.

Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. The Partnership expects claims in each of these cases to be covered by insurance that was in place at the time of the incident. For the years ended December 2008, 2007 and 2006 the Partnership received \$4.7 million, \$0.3 million and \$0.8 million in insurance proceeds related to previously incurred litigation and remediation costs, which were recorded as reductions to Operating Costs and Expenses.

Other Legal Matters

In October 2008, FERC issued an order with respect to an interstate natural gas pipeline not affiliated with the Partnership. Among other things, the order redefined what types of changes to a contract within FERC's jurisdiction will be viewed by FERC as a material deviation, thereby requiring that the contract be filed with and approved by FERC. As a result, in the fall 2008, the Partnership initiated a systematic review of its transportation and storage contracts for both Gulf South and Texas Gas in order to verify compliance with the order. Based upon the preliminary findings of this review, the Partnership has self-reported to FERC that certain of its transportation and storage contracts may not be in compliance with the requirements of the order. The Partnership is continuing its review and is scheduled to meet with FERC staff in the first quarter 2009 to review its findings and discuss additional steps to be taken, if any. Although this matter is in a preliminary stage, the Partnership does not expect the outcome to have a material impact on its financial condition, results of operations or cash flows.

In connection with the acquisition of Texas Gas in 2003, The Williams Companies, Inc. (Williams) agreed to indemnify Boardwalk Pipelines for any liabilities or obligations in connection with certain litigation or potential litigation. Williams continues to defend the Partnership and Texas Gas and has retained responsibility for these claims. Therefore these claims are not expected to have a material effect upon the Partnership's future financial condition, results of operations or cash flows.

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

Regulatory and Rate Matters

Pipeline Expansion Projects

The Partnership is engaged in several pipeline expansion projects as follows:

| | Pipeline Mileage (unaudited) | Pipeline Diameter (unaudited) | Peak-day Transmission Capacity (unaudited) | In Service Date (unaudited) |
|-----------------------|---|--|---|--|
| Southeast Expansion | 111 miles | 42-inch | 1.9 Bcf (a) | First quarter 2009 |
| Gulf Crossing Project | 357 miles | 42-inch | 1.7 Bcf (a),(b) | First quarter 2009 |
| Fayetteville Lateral | 165 miles | 36-inch | 1.3 Bcf (a),(b) | First quarter 2009 |
| Greenville Lateral | 95 miles | 36-inch | 1.0 Bcf (b) | First quarter 2009 |

- (a) The indicated peak-day transmission capacity (shown in billion cubic feet (Bcf)) is subject to the receipt of authority from the Pipelines and Hazardous Materials Safety Administration (PHMSA) to operate the pipelines at higher operating pressures.
- (b) The indicated peak-day transmission capacity is subject to the construction of additional compression facilities which, subject to FERC approval, are expected to be placed in service in 2010.

Southeast Expansion. In February 2009, the Partnership placed in service the remaining compression related to this project and construction on this project is complete. Customers have contracted at fixed rates for substantially all of the operational capacity (with a weighted-average term of approximately 9.3 years, including a capacity lease agreement with Gulf Crossing). Through December 31, 2008, the Partnership spent \$707.3 million related to this project.

Gulf Crossing Project. In January and February 2009, the Partnership completed construction and placed in service the pipeline portion of the assets associated with the Gulf Crossing project, which consists of approximately 357 miles of 42-inch pipeline that begins near Sherman, Texas and proceeds to the Perryville,

Louisiana area. Customers have contracted at fixed rates for substantially all of the operational capacity, with a weighted-average term of approximately 9.5 years. The Partnership expects the initial compression to be placed in service during the first quarter 2009. The pipeline will initially be operating at a reduced capacity until authority to operate under a special permit from PHMSA is received that will allow the pipeline to operate at higher operating pressures. The remaining compression is expected to be fully in service in 2010. Through December 31, 2008, the Partnership spent \$1.4 billion related to this project.

Fayetteville and Greenville Laterals. The Partnership is constructing two laterals on its Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by the Partnership's existing interstate pipelines. The Fayetteville Lateral will originate in Conway County, Arkansas, and proceed southeast through the Bald Knob, Arkansas area, to an interconnect with the Texas Gas mainline in Coahoma County, Mississippi. The Greenville Lateral will originate at the Texas Gas mainline near Greenville, Mississippi, and proceed east to the Kosciusko, Mississippi area. The Greenville Lateral will provide customers access to additional markets, located primarily in the Midwest, Northeast and Southeast. In December 2008, the Partnership placed in service the header of the Fayetteville Lateral. In January 2009, the Partnership placed in service a portion of the Greenville Lateral which originates at the Texas Gas mainline and continues to an interconnect with the Tennessee 800 line in Holmes County, Mississippi. The Fayetteville header includes a section of 18-inch pipeline under the Little Red River in Arkansas which will be replaced with 36-inch pipeline once a new horizontal directional drill is completed under the river. The Partnership expects the 36-inch pipeline installation to be completed in the second quarter 2009.

During 2008, the Partnership executed contracts for additional capacity that will require it to add compression to increase the peak-day transmission capacity of the laterals. Customers have contracted at fixed rates for substantially all of the operational capacity of these laterals, with a weighted-average term of approximately 9.9 years. The Partnership made additional filings with FERC regarding the new compression required to increase the peak-day transmission capacity, and expects the compression to be in service during 2010. Through December 31, 2008, the Partnership spent \$684.2 million related to the Fayetteville and Greenville Laterals.

Storage Expansion Project

The Partnership is also engaged in the following storage expansion project:

Western Kentucky Storage Expansion Phase III. The Partnership is developing new working gas capacity at its Midland storage facility for which FERC has granted the Partnership market-based rate authority. Through December 31, 2008, the Partnership spent \$48.0 million related to this project.

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. The Partnership accrues for environmental expenses resulting from existing conditions that relate to past operations when the costs are probable and can be reasonably estimated. In addition to federal and state mandated remediation requirements, the Partnership often enters into voluntary remediation programs with regulatory agencies. Depending on the results of on-going assessments and review of any data collected, the Partnership's liabilities for environmental remediation are updated based on new facts and circumstances. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the Environmental Protection Agency (EPA) or other governmental authorities and other factors.

As of December 31, 2008 and 2007, the Partnership had an accrued liability of approximately \$16.8 million and \$17.0 million related to assessment and/or remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, enhancement of groundwater protection measures and other costs. The expenditures are expected to occur over the next ten years. The accrual 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. As of December 31, 2008

and 2007, approximately \$3.5 million and \$2.7 million were recorded in Other current liabilities and approximately \$13.3 million and \$14.3 million were recorded in Other Liabilities and Deferred Credits. The Partnership considers environmental assessment, remediation costs and costs associated with compliance with environmental standards to be recoverable through base rates, as they are prudent costs incurred in the ordinary course of business and, therefore, no regulatory asset has been recorded to defer these costs. For further discussion of the Partnership's environmental exposure included in the calculation of its asset retirement obligations, see Note 5 of these Notes to Consolidated Financial Statements.

Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA)

In 2006, Texas Gas received notice from the EPA that Texas Gas is a potentially responsible party under the CERCLA of 1980 with respect to the LWD, Inc. Superfund Site in Calvert City, Kentucky. The Partnership is unable to estimate with any certainty at this time any potential liability it may incur related to this notice but does not expect the outcome to have a material effect on its financial condition, results of operations or cash flows.

In 2005, Texas Gas received notice from the EPA that it has been identified as a *de minimis* settlement waste contributor at the Mercury Refining Superfund Site located at the Towns of Colonie and Guilderland, Albany County, New York, and was offered and accepted participation in a settlement. In January 2009, Texas Gas and Gulf South received a revised notice from the EPA identifying both parties as *de minimis* waste contributors at the site. Based upon the EPA's notice, the proposed total settlement amount for both subsidiaries is approximately \$0.1 million. The proposed settlement is subject to a 30 day public notice period before it can be finalized.

Clean Air Act

The Partnership's pipelines are subject to the Clean Air Act (CAA) and the CAA Amendments of 1990 (Amendments) which added significant provisions to the CAA. The Amendments require the EPA to promulgate new regulations pertaining to mobile sources, air toxins, areas of ozone non-attainment and acid rain. The operating subsidiaries presently operate two facilities in areas affected by non-attainment requirements for the current ozone standard (eight-hour standard). If the EPA designates additional new non-attainment areas or promulgates new air regulations where the Partnership operates, the cost of additions to PPE is expected to increase. The Partnership has assessed the impact of the CAA on its facilities and does not believe compliance with these regulations will have a material impact on the results of continuing operations or cash flows. If the EPA designates additional new non-attainment areas or promulgates new air regulations applicable to the Partnership's operating subsidiaries, the cost of additions to PPE is expected to increase.

In March 2008, the EPA adopted regulations lowering the 8-hour ozone standard relevant to non-attainment areas. Under the regulation, new non-attainment areas will be identified which may require additional emission controls for compliance at as many as 12 facilities operated by the operating subsidiaries. The mandated compliance dates for this standard are between 2013 and 2016. The Partnership is currently evaluating its potentially affected facilities to determine the cost necessary to become compliant with this standard.

Lease Commitments

The Partnership has various operating lease commitments extending through the year 2018 generally covering office space and equipment rentals. Total lease expense for the years ended December 31, 2008, 2007 and 2006 were approximately \$4.4 million, \$5.0 million and \$2.4 million. The following table summarizes minimum future commitments related to these items at December 31, 2008 (in millions):

| | | |
|------------|----|------|
| 2009 | \$ | 3.3 |
| 2010 | | 3.2 |
| 2011 | | 3.0 |
| 2012 | | 3.0 |
| 2013 | | 3.0 |
| Thereafter | | 10.2 |
| Total | \$ | 25.7 |

Commitments for Construction

The Partnership incurred \$2.7 billion and \$1.2 billion of capital expenditures in 2008 and 2007. 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 existing at December 31, 2008. The commitments as of December 31, 2008 were approximately (in millions):

| | | |
|-------------------|----|-------|
| Less than 1 year | \$ | 195.8 |
| 1-3 years | | 2.9 |
| 4-5 years | | - |
| More than 5 years | | - |
| Total | \$ | 198.7 |

Pipeline Capacity Agreements

The Partnership's subsidiaries have entered into pipeline capacity agreements with third-party pipelines that allow the subsidiaries to transport gas to off-system markets on behalf of customers. The Partnership incurred expenses of \$6.4 million, \$2.3 million and \$2.3 million related to pipeline capacity agreements for the years ended December 31, 2008, 2007 and 2006. The future commitments related to pipeline capacity agreements as of December 31, 2008 were (in millions):

| | | |
|-------------------|----|-------|
| Less than 1 year | \$ | 12.6 |
| 1-3 years | | 22.5 |
| 4-5 years | | 20.5 |
| More than 5 years | | 47.2 |
| Total | \$ | 102.8 |

Note 4: Property, Plant and Equipment

In 2008, the Partnership placed in service the remaining pipeline assets and related compression associated with the East Texas to Mississippi Expansion project from Delhi, Louisiana to Harrisville, Mississippi. The Partnership also placed in service the pipeline assets and two compressor stations related to the Southeast Expansion project, the pipeline assets associated with the first 66 miles of the Fayetteville Lateral and Phase III of the Western Kentucky Storage Expansion. Approximately \$1.5 billion was transferred from Construction work in progress to

Property, plant and equipment during 2008 as a result of these assets being placed in service. The assets will generally be depreciated over a term of 35 years.

The following table presents the Partnership's PPE as of December 31, 2008 and 2007 (in millions):

| Category | 2008 Class Amount | Weighted- Average Useful Lives (Years) | 2007 Class Amount | Weighted- Average Useful Lives (Years) |
|---------------------------------|------------------------------|---|------------------------------|---|
| Depreciable plant: | | | | |
| Transmission | \$ 3,537.2 | 39 | \$ 2,125.9 | 43 |
| Storage | 248.9 | 47 | 198.1 | 49 |
| Gathering | 91.4 | 19 | 92.8 | 19 |
| General | 88.3 | 15 | 79.6 | 15 |
| Rights of way and other | 36.9 | 24 | 24.9 | 9 |
| Total utility depreciable plant | 4,002.7 | 39 | 2,521.3 | 41 |
| Non-depreciable: | | | | |
| Construction work in progress | 2,196.4 | | 951.4 | |
| Storage | 61.6 | | 71.2 | |
| Land | 13.3 | | 9.7 | |
| Other | 8.6 | | 14.3 | |
| Total other | 2,279.9 | | 1,046.6 | |
| Total PPE | 6,282.6 | | 3,567.9 | |
| Less: accumulated depreciation | 382.4 | | 262.5 | |
| Total PPE, net | \$ 5,900.2 | | \$ 3,305.4 | |

The non-transmission assets have weighted-average useful lives of 35 years and 33 years as of December 31, 2008 and 2007 and depreciable asset values of \$465.5 million and \$395.4 million as of December 31, 2008 and 2007. The non-depreciable assets and construction work in progress 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. The proportionate share of investment associated with these interests has been recorded as PPE on the Consolidated 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, 2008 and 2007 (in millions):

| | 2008 | | 2007 | |
|---------------------------|---------------------------------|-------------------------------------|---------------------------------|-------------------------------------|
| | Gross PPE Investment | Accumulated Depreciation | Gross PPE Investment | Accumulated Depreciation |
| Bistineau storage | \$ 57.1 | \$ 6.9 | \$ 57.0 | \$ 5.2 |
| Mobile Bay Pipeline | 11.2 | 1.4 | 11.2 | 1.0 |
| Offshore and other assets | 19.0 | 11.5 | 19.3 | 11.2 |
| Total | \$ 87.3 | \$ 19.8 | \$ 87.5 | \$ 17.4 |

Asset Impairments

Non-Contiguous Offshore Laterals. In 2008, the Partnership completed a review of its non-contiguous offshore laterals and provided notice to the other interest holders of its intent to discontinue use of its portion of the available capacity for some of the assets. As a result, the Partnership reviewed the assets for recoverability in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, and recorded an impairment charge of approximately \$3.0 million representing the net book value of the assets.

South Timbalier. In 2007, the Partnership entered into an agreement to sell offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, and recognized an impairment charge of approximately \$4.5 million representing the net book value of the assets. In accordance with the agreement, the Partnership paid the buyer approximately \$4.8 million primarily to settle a liability to re-cover the pipeline and other maintenance issues which was recorded to Operation and maintenance expense. The Partnership completed the sale of these assets in 2008.

Magnolia Storage Facility. The Partnership was developing a salt dome storage cavern near Napoleonville, Louisiana. Integrity tests, which were completed in 2007, indicated that due to geological and other anomalies that could not be corrected, the Partnership would be unable to place the cavern in service as expected. As a result, the Partnership elected to abandon that cavern. In accordance with the requirements of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*, the carrying value of the cavern and related facilities was tested for recoverability. In 2007, the Partnership recognized an impairment charge to earnings of approximately \$14.7 million, representing the carrying value of the cavern, the fair value of which was determined to be zero based on discounted expected future cash flows. The charge was presented as Asset impairment on the Consolidated Statements of Income in 2007. The Partnership is exploring the possibility of securing a new site in Napoleonville, Louisiana, on which a new cavern could be developed and expects to use the other assets associated with the project, which include pipeline, compressors, and other equipment and facilities, in conjunction with the replacement storage cavern to be developed. If it is determined in the future that the assets cannot be used in conjunction with a new cavern or a new cavern cannot be secured in the same area, the Partnership may be required to record an additional impairment charge at the time that determination is made. Additional costs to abandon the impaired cavern may be incurred due to regulatory or contractual obligations; however, the amounts are inestimable at this time.

Note 5: Asset Retirement Obligations (ARO)

Pursuant to federal regulations, the Partnership has a legal obligation to cut and purge any pipeline that will remain in place after abandonment and to remove offshore platforms after the related gas flows have ceased. The Partnership has identified and recorded legal obligations associated with the abandonment of offshore pipeline laterals and certain onshore facilities as well as abatement of asbestos consisting of removal, transportation and disposal when removed from certain compressor stations and meter station buildings. Legal obligations exist for the pipeline and certain other Partnership assets; however, the fair value of the obligations cannot be determined because the lives of the assets are indefinite and 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 (in millions):

| | 2008 | 2007 |
|------------------------------|----------------|----------------|
| Balance at beginning of year | \$ 16.1 | \$ 14.3 |
| Liabilities recorded | 1.6 | 1.5 |
| Liabilities settled | (0.5) | (0.4) |
| Accretion expense | 0.8 | 0.7 |
| Balance at end of year | <u>\$ 18.0</u> | <u>\$ 16.1</u> |

The Financial Accounting Standards Board (FASB) Interpretation No. 47, *Accounting for Conditional AROs*, clarifies when an entity is required to recognize a liability for the fair value of a conditional ARO. In light of

this interpretation, the Partnership believes that an ARO exists for the Texas Gas corporate office building constructed in Owensboro, Kentucky, in 1962. Under the legal requirements enacted by the EPA during 1973, Texas Gas became legally obligated to dismantle and remove the asbestos from its corporate office at the end of its useful life, estimated to be within a range between 2112 through 2162. The Partnership believes that the spray-applied asbestos can be maintained in place indefinitely, if undisturbed by following written maintenance procedures. The Partnership believes that the fair value of any liability relating to future remediation is not material to its financial position, results of operations or cash flows and that any costs incurred for this remediation would be recoverable in its rates.

For the Partnership's operations where SFAS No. 71 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 (negative salvage) which is collected in rates and does not represent an existing legal obligation. The Partnership has reflected \$45.6 million and \$42.4 million as of December 31, 2008 and 2007, in the accompanying Consolidated Balance Sheets as Provision for other asset retirement related to the estimated cost of removal collected in rates.

Note 6: Regulatory Assets and Liabilities

The amounts recorded as regulatory assets and liabilities in the Consolidated Balance Sheets as of December 31, 2008 and 2007, are summarized in the table below. The table also includes amounts related to unamortized debt expense and unamortized discount on long-term debt. While these amounts are not regulatory assets and liabilities as defined by SFAS No. 71, they are a critical component of the embedded cost of debt financing utilized in the Texas Gas rate proceedings. The tax effect of the equity component of AFUDC represents amounts recoverable from rate payers for the tax effects created prior to the 2005 change in the tax status of Boardwalk Pipelines and its election to be taxed as a partnership. Certain amounts in the table are reflected as a negative, or a reduction, to be consistent with the manner in which Texas Gas records these items in its regulatory books of account. The period of recovery for the regulatory assets included in rates varies from one to nineteen 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, 2008 and 2007 (in millions):

| | <u>2008</u> | <u>2007</u> |
|---|----------------|----------------|
| Regulatory Assets: | | |
| Pension | \$ 9.5 | \$ 9.5 |
| Tax effect of AFUDC equity | 5.9 | 6.4 |
| Unamortized debt expense and premium on reacquired debt | 10.0 | 10.7 |
| Postretirement benefits other than pension | 5.4 | 5.4 |
| Fuel tracker | - | 0.9 |
| Total regulatory assets | <u>\$ 30.8</u> | <u>\$ 32.9</u> |
| Regulatory Liabilities: | | |
| Cashout and fuel tracker | \$ 2.3 | \$ 0.2 |
| Provision for asset retirement | 45.6 | 42.4 |
| Unamortized discount on long-term debt | (3.5) | (1.7) |
| Postretirement benefits other than pension | 4.7 | 12.5 |
| Total regulatory liabilities | <u>\$ 49.1</u> | <u>\$ 53.4</u> |

Note 7: Financing

Issuances of Common Units

Since its IPO in November 2005, the Partnership has completed four follow-on public equity offerings and one private placement of common units. The proceeds of the offerings have been used to finance the Partnership's expansion activities discussed in Note 3 or to reduce borrowings under the Partnership's revolving credit facility. In addition to funds received from the offering of common units, the general partner concurrently contributed amounts to maintain its 2% interest in the Partnership. The following table shows selected information related to these equity issuances (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 |
|--------------------------|-------------------------------|-----------------------|---|--|--|---|
| October 2008 (a) | 21.2 | \$ 23.13 | - | \$ 500.0 | 121.8 (b) | 47.4 |
| June 2008 | 10.0 | 25.30 | \$ 9.4 | 248.8 | 100.7 | 47.4 |
| November 2007 | 7.5 | 30.90 | 3.7 | 232.8 | 90.7 | 37.4 |
| March 2007 | 8.0 | 36.50 | 4.2 | 293.8 | 83.2 | 29.9 |
| November 2006 | 6.9 | 29.65 | 9.4 | 199.4 | 75.2 | 21.9 |

(a) Sold to BPHC in a private placement.

(b) Excludes the conversion of all of the 33.1 million subordinated units into common units in November 2008.

Class B Units

In June 2008, the Partnership issued and sold, pursuant to the Class B Unit Purchase Agreement (the Purchase Agreement), approximately 22.9 million class B units representing limited partner interests (class B units) to BPHC for \$30.00 per class B unit, or an aggregate purchase price of \$686.0 million. The Partnership's general partner also contributed \$14.0 million to the Partnership to maintain its 2% interest. The Partnership used the proceeds of \$700.0 million to repay amounts borrowed under its revolving credit facility and to fund a portion of the costs of its ongoing expansion projects.

The class B units share in quarterly distributions of available cash from operating surplus on a pari passu basis with the Partnership's common units, until each common unit and class B unit has received a quarterly distribution of \$0.30. The class B units do not participate in quarterly distributions above \$0.30 per unit. The class B units began sharing in income allocations and distributions with respect to the third quarter 2008.

The class B units have the same voting rights as if they were outstanding common units and are entitled to vote as a separate class on any matters that materially adversely affect the rights or preferences of the class B units in relation to other classes of partnership interests or as required by law. The class B units will be convertible into common units upon demand by the holder on a one-for-one basis at any time after June 30, 2013.

Registration Rights Agreement

In conjunction with the sale of class B units and common units to BPHC in 2008, the Partnership entered into a registration rights agreement with BPHC. Under the terms of the agreement, the Partnership has agreed to pay the costs of maintaining an effective registration statement at BPHC's option, including accounting and legal expenses, for the sale of common units BPHC has acquired as a result of the purchase of common units in October 2008, or conversion of the class B units into common units. In addition the Partnership has agreed to pay the underwriting discount on the sale of the first 21.2 million units by BPHC up to \$0.925 per common unit. As a result,

in 2008, the Partnership recorded a liability and reduced Partner's Capital by \$20.6 million to recognize the contingent obligation to BPHC.

Conversion of Subordinated Units

In November 2008, the Partnership satisfied the last of the earnings and distribution tests contained in its partnership agreement for the conversion into common units on a one-for-one basis of all of the 33.1 million then outstanding subordinated units held by BPHC. The last of these requirements was met coincident with payment of the quarterly distribution in the fourth quarter 2008. Two days following the distribution, all of the subordinated units converted to common units.

Long-Term Debt

The following table presents all long-term debt issues outstanding (in millions):

| | December 31, | |
|-----------------------------------|--------------------------|--------------------------|
| | 2008 | 2007 |
| Notes and Debentures: | | |
| Boardwalk Pipelines | | |
| 5.88% Notes due 2016 | \$ 250.0 | \$ 250.0 |
| 5.20% Notes due 2018 | 185.0 | 185.0 |
| 5.50% Notes due 2017 | 300.0 | 300.0 |
| Gulf South | | |
| 6.30% Notes due 2017 | 275.0 | 275.0 |
| 5.75% Notes due 2012 | 225.0 | 225.0 |
| 5.05% Notes due 2015 | 275.0 | 275.0 |
| Texas Gas | | |
| 7.25% Debentures due 2027 | 100.0 | 100.0 |
| 4.60% Notes due 2015 | 250.0 | 250.0 |
| 5.50% Notes due 2013 | 250.0 | - |
| Total notes and debentures | <u>2,110.0</u> | <u>1,860.0</u> |
| Revolving Credit Facility: | | |
| Boardwalk Pipelines | 285.0 | - |
| Gulf South | 317.0 | - |
| Texas Gas | 190.0 | - |
| Total revolving credit facility | <u>792.0</u> | <u>-</u> |
| | <u>2,902.0</u> | <u>1,860.0</u> |
| Less: unamortized debt discount | (12.6) | (12.1) |
| Total Long-Term Debt | <u><u>\$ 2,889.4</u></u> | <u><u>\$ 1,847.9</u></u> |

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

| | |
|----------------------|-------------------|
| 2009 | - |
| 2010 | - |
| 2011 | - |
| 2012 | \$ 1,017.0 |
| 2013 | 250.0 |
| Thereafter | 1,635.0 |
| Total long-term debt | <u>\$ 2,902.0</u> |

Notes and Debentures

For the years ended December 30, 2008 and 2007, the Partnership completed the following debt issuances of notes and debentures (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 |
|-------------------------|---------------------------|---------------------------|---|---------------------|----------------------|----------------------|---------------------------|
| March 2008 | Texas Gas | \$250.0 | \$2.8 | \$247.2 | 5.50% | April 1, 2013 | April 1 and October 1 |
| August 2007 | Gulf South | 225.0 | 2.0 | 223.0 | 5.75% | August 15, 2012 | February 15 and August 15 |
| August 2007 | Gulf South | 275.0 | 2.7 | 272.3 | 6.30% | August 15, 2017 | February 15 and August 15 |

The notes are redeemable, in whole or in part, at the Partnership's option at any time, at redemption prices 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. As of December 31, 2008 and 2007, the weighted-average interest rate of the Partnership's senior unsecured debt was 5.89% and 5.82%, excluding amounts borrowed under the revolving credit agreement.

The indentures governing the notes 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 debt obligations are unsecured. At December 31, 2008, Boardwalk Pipelines and the operating subsidiaries were in compliance with their debt covenants.

Revolving Credit Facility

The Partnership has a revolving credit facility which has aggregate lending commitments of \$1.0 billion. A financial institution which has a \$50.0 million commitment under the revolving credit facility filed for bankruptcy protection in the third quarter 2008 and has not funded its portion of the Partnership's borrowing requests since that time. Borrowings outstanding under the credit facility as of December 31, 2008, were \$792.0 million with a weighted-average borrowing rate of 3.43%. Subsequent to December 31, 2008, the Partnership borrowed all of the remaining unfunded commitments under the credit facility (excluding the unfunded commitment of the bankrupt lender noted above) which increased borrowings to \$953.5 million.

As of December 31, 2007, no funds were drawn under the credit facility, however, the Partnership had outstanding letters of credit under the facility for \$185.6 million to support certain obligations associated with the pipeline expansion projects which reduced the available capacity under the facility by such amount. The letters of credit were reduced to zero as the Partnership met its related obligations.

The credit facility contains various restrictive covenants and other usual and customary terms and conditions, including limitations on the payment of cash dividends by our subsidiaries and other restricted payments, the incurrence of additional debt, the sale of assets, and sales-leaseback transactions. The financial covenants under the 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 credit agreement) measured for the previous twelve months, of not more than 5.0 to 1.0. The Partnership and its subsidiaries were in compliance with all covenant requirements under the credit facility as of December 31, 2008 and 2007.

Note 8: Derivatives

Subsidiaries of the Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to various risks, including natural gas commodity price risk and interest rate risk. These hedge contracts are reported at fair value in accordance with SFAS No. 133, as amended.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At December 31, 2008 and December 31, 2007, approximately \$0.2 million and \$16.3 million of gas stored underground, which the Partnership owns and carries on its Consolidated Balance Sheets as current Gas stored underground, was exposed to commodity price risk. The Partnership utilizes derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

In 2008, as a result of Phase III of the Western Kentucky Storage Expansion project approximately 5.1 Bcf of gas stored underground with a book value of \$11.8 million became available for sale. The Partnership entered into derivatives, which were designated as cash flow hedges, to hedge the price exposure related to the expected sale of this gas. The gas was subsequently sold and the related derivatives were settled, resulting in a gain of \$34.4 million for the year ended December 31, 2008, which was reported in Net gain on disposal of operating assets and related contracts on the Consolidated Statements of Income. In 2007, approximately 4.0 Bcf of gas related to Phase II of the Western Kentucky Storage Expansion project was sold and the related derivatives were settled, resulting in a gain of \$22.0 million.

In 2007, the Partnership entered into natural gas price swaps to hedge exposure to prices associated with the purchase of 2.1 Bcf of natural gas to be used for line pack for pipeline expansion projects. The derivatives were not designated as hedges and were marked to fair value through earnings resulting in a gain of \$0.9 million in Miscellaneous other income, net on the Consolidated Statements of Income for the year ended December 31, 2008 and a loss of \$0.9 million for the year ended December 31, 2007. These derivatives were settled in connection with the purchase of the gas in 2008.

In 2007, the Partnership entered into a Treasury rate lock for a notional amount of \$150.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through February 1, 2008. The Treasury rate lock was designated as a cash flow hedge in accordance with SFAS No. 133. As of December 31, 2007, the Partnership recorded a payable of \$8.4 million and a corresponding amount in Accumulated other comprehensive (loss) income for the fair value of the rate lock. On February 1, 2008, the Partnership settled the rate lock and paid the counterparty approximately \$15.0 million which was deferred as a component of Accumulated other comprehensive (loss) income. The loss will be amortized to interest expense over 10 years.

The derivatives related to the sale of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The effective component of related unrealized gains and losses resulting from changes in fair values of the derivatives designated as cash flow hedges are deferred as a component of Accumulated other comprehensive (loss) income. The deferred gains and losses are recognized in the Consolidated Statements of Income when the anticipated transactions affect earnings. In situations where continued reporting of a loss in Accumulated other comprehensive (loss) income would result in recognition of a future loss on the combination of the derivative and the hedged transaction, SFAS No. 133 requires that the loss be immediately recognized in earnings for the amount that is not expected to be recovered. The Partnership reclassified losses of \$1.7 million for the twelve months ended December 31, 2008, from Accumulated other comprehensive (loss) income to earnings related to amounts that are not expected to be recovered in future periods from the combination of sales of gas stored underground and the deferred losses associated with related derivatives.

Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues. For the sale of gas related to the Western Kentucky Storage Expansion projects, any gains and losses on the related derivatives were recognized in Net gain on disposal of operating assets and related contracts. Any gains and losses on the derivatives related to the line pack gas purchases would be recognized in Miscellaneous other income, net.

The changes in fair values of the derivatives designated as cash flow hedges are expected to, and do, have a high correlation to changes in value of the anticipated transactions. Each reporting period the Partnership measures the effectiveness of the cash flow hedge contracts. To the extent the changes in the fair values of the hedge contracts do not effectively offset the changes in the estimated cash flows of the anticipated transactions, the ineffective portion of the hedge contracts is currently recognized in earnings. If the anticipated transactions are deemed no longer probable to occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in earnings. Less than \$0.1 million of ineffectiveness was recorded for the year ended December 31, 2008. Ineffectiveness decreased Net income by \$0.1 million for the year ended December 31, 2007 and increased Net income by \$0.5 million for the year ended December 31, 2006. The Partnership did not discontinue any cash flow hedges during the years ended December 31, 2008 and 2007. The derivatives existing at December 31, 2008 have settlement dates of 2009 and 2010.

The fair values of derivatives existing as of December 31, 2008 and 2007, were included in the following captions in the Consolidated Balance Sheets (in millions):

| | December 31, | |
|--------------------------------------|---------------------|-------------|
| | 2008 | 2007 |
| Other current assets | \$ 10.5 | \$ 2.2 |
| Other assets | 3.7 | - |
| Other current liabilities | (0.1) | 9.4 |
| Accumulated other comprehensive loss | (0.7) | (8.9) |

Note 9: Fair Value

SFAS No. 157, Fair Value Measurements

In 2008, the Partnership implemented the provisions of SFAS No. 157, except for the provisions related to non-financial assets and liabilities measured at fair value on a non-recurring basis, which provisions will be applied beginning in 2009. Fair value refers to the 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. SFAS No. 157 establishes a fair value hierarchy 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 identified its derivatives and short-term investments as items governed by the provisions of SFAS No. 157 as of December 31, 2008. The derivatives in existence at December 31, 2008, were natural gas price swaps and options, which were recorded at fair value based on New York Mercantile Exchange (NYMEX) quotes for natural gas futures and options. The NYMEX quotes were deemed to be observable inputs for similar assets and liabilities and rendered Level 2 inputs for purposes of disclosure. The short-term investments consist of U.S. Government securities, primarily Treasury notes, under overnight repurchase agreements. These investments are recorded at fair value based on the quoted prices in active markets of the securities and rendered Level 1 inputs for purposes of disclosure. The application of SFAS No. 157 had no effect on the Partnership's financial statements.

The fair values of derivatives and short-term investments existing as of December 31, 2008, were included in the following captions in the Consolidated Balance Sheets (in millions):

| | Total at December 31, 2008 | Quoted Prices in Active Markets for Identical Assets Level 1 | Significant Other Observable Inputs Level 2 | Significant Unobservable Inputs Level 3 |
|---------------------------|----------------------------------|--|---|--|
| Assets: | | | | |
| Short-term investments | \$ 175.0 | \$ 175.0 | - | - |
| Other current assets | 10.5 | - | \$ 10.5 | - |
| Other assets | 3.7 | - | 3.7 | - |
| Total assets | <u>\$ 189.2</u> | <u>\$ 175.0</u> | <u>\$ 14.2</u> | <u>-</u> |
| Liabilities: | | | | |
| Other current liabilities | \$ (0.1) | - | \$ (0.1) | - |
| Total liabilities | <u>\$ (0.1)</u> | <u>-</u> | <u>\$ (0.1)</u> | <u>-</u> |

SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities

In 2008, the Partnership had the option to apply the provisions of SFAS No. 159, which allows companies to elect to measure and record certain financial assets and liabilities at fair value that would not otherwise be recorded at fair value, such as long-term debt or notes receivable. Unrealized gains and losses on items for which the fair value option was chosen would be reported in earnings. The Partnership reviewed its financial assets and liabilities in existence at January 1, 2008, as well as any financial assets and liabilities entered into during 2008, and did not elect the fair value option for any applicable items. Consequently, the application of SFAS No. 159 had no effect on the Partnership's financial statements.

Note 10: Employee Benefits

Retirement Plans

Texas Gas employees hired before November 1, 2006, are covered under a non-contributory, defined benefit pension plan. The Texas Gas Supplemental Retirement Plan (SRP) provides pension benefits for the portion of an eligible employee's pension benefit that becomes subject to compensation limitations under the Internal Revenue Code. Effective November 1, 2006, the defined benefit pension plan was closed to new participants and new employees are provided benefits under a defined contribution money purchase plan. The Partnership uses a measurement date of December 31 for its benefits plans.

As a result of its rate case settlement in 2006, the Partnership is required to fund the amount of the Texas Gas annual net periodic pension cost, including a minimum of \$3.0 million which is the amount included in rates. In 2008, the Partnership funded \$4.6 million to the Texas Gas retirement plan and expects to fund approximately \$5.0 million to the plan in 2009. Through December 31, 2008, no funding has been provided for the SRP other than the payment of benefits under the plan, and the Partnership does not expect to fund this plan in the future until such time as benefits are paid.

The Partnership recognizes each year the actuarially determined amount of net periodic pension cost in expense, including a minimum amount of \$3.0 million, in accordance with the rate case settlement. Texas Gas is permitted to seek future rate recovery for amounts of annual pension costs in excess of \$6.0 million and is precluded from seeking future recovery of annual pension costs between \$3.0 and \$6.0 million. As a result, the Partnership would recognize a regulatory asset for amounts of annual pension cost in excess of \$6.0 million and would reduce its regulatory asset to the extent that any amounts of annual pension cost are less than \$3.0 million. Annual pension 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. The Partnership

contributed \$0.8 million, \$0.9 million and \$0.3 million to the plan in 2008, 2007 and 2006. Due to plan changes regarding benefits available to current and future retirees described below, the PBOP plan is currently in an overfunded status, therefore the Partnership does not expect to make any contributions to the plan in 2009. Due to the Texas Gas rate case settlement in 2006, the Partnership began to amortize the balance of its regulatory asset for PBOP of approximately \$32.0 million on a straight-line basis over 5 to 6 years.

Early Retirement Incentive Program

In 2006, Texas Gas implemented an early retirement incentive program (ERIP) which was made available to approximately 240 non-executive employees age 52 and older with at least five years of service. Under the program, Texas Gas provided eligible employees three additional years for purposes of age-based vesting under the postretirement medical plan and three additional years of pay credits under the pension plan. In 2007, all of the approximately 100 employees who elected to participate in the program retired and the Partnership recognized a settlement charge of \$4.5 million related to the program. The Partnership recognized a special termination benefit of approximately \$6.0 million for pension and \$0.9 million for PBOP in 2006.

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, 2008 and 2007, were as follows (in millions):

| | Retirement Plans | | PBOP | |
|--|--|------------------|--|------------------|
| | For the Year Ended December 31, | | For the Year Ended December 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| Change in benefit obligation: | | | | |
| Benefit obligation at beginning of period | \$ 108.5 | \$ 136.9 | \$ 56.9 | \$ 65.3 |
| Service cost | 3.7 | 3.9 | 0.6 | 0.6 |
| Interest cost | 6.5 | 6.6 | 3.2 | 3.3 |
| Plan participants' contributions | - | - | 1.1 | 0.8 |
| Actuarial gain | (3.4) | (2.2) | (6.2) | (9.3) |
| Benefits paid | (4.0) | (0.6) | (3.2) | (4.1) |
| Settlement | (1.4) | (36.1) | - | - |
| Retiree drug subsidy | - | - | - | 0.3 |
| Benefit obligation at end of period | <u>\$ 109.9</u> | <u>\$ 108.5</u> | <u>\$ 52.4</u> | <u>\$ 56.9</u> |
| Change in plan assets: | | | | |
| Fair value of plan assets at beginning of period | \$ 91.3 | \$ 121.1 | \$ 84.2 | \$ 80.2 |
| Actual return on plan assets | (16.3) | 6.5 | (16.2) | 6.4 |
| Benefits paid | (4.0) | (0.6) | (3.2) | (4.1) |
| Company contributions | 4.6 | 0.4 | 0.8 | 0.9 |
| Plan participants' contributions | - | - | 1.1 | 0.8 |
| Settlement | (1.4) | (36.1) | - | - |
| Fair value of plan assets at end of period | <u>\$ 74.2</u> | <u>\$ 91.3</u> | <u>\$ 66.7</u> | <u>\$ 84.2</u> |
| Funded status | <u>\$ (35.7)</u> | <u>\$ (17.2)</u> | <u>\$ 14.3</u> | <u>\$ 27.3</u> |
| Items not recognized as components of net periodic cost: | | | | |
| Prior service cost (credit) | \$ 0.1 | \$ 0.1 | \$ (55.2) | \$ (63.0) |
| Net actuarial loss | 31.0 | 11.7 | 25.6 | 10.7 |
| Total | <u>\$ 31.1</u> | <u>\$ 11.8</u> | <u>\$ (29.6)</u> | <u>\$ (52.3)</u> |

The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2009. At December 31, 2008 and 2007, the following aggregate information relates only to the underfunded retirement plan (in millions):

| | For the Year Ended December 31, | |
|--------------------------------|--|-------------|
| | 2008 | 2007 |
| Projected benefit obligation | \$ 109.9 | \$ 108.5 |
| Accumulated benefit obligation | 97.4 | 94.6 |
| Fair value of plan assets | 74.2 | 91.3 |

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, 2008, 2007 and 2006 were the following (in millions):

| | Retirement Plans | | | PBOP | | |
|---------------------------------------|--|---------------|---------------|--|-----------------|---------------|
| | For the Year Ended December 31, | | | For the Year Ended December 31, | | |
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Service cost | \$ 3.7 | \$ 3.9 | \$ 4.4 | \$ 0.6 | \$ 0.6 | \$ 1.3 |
| Interest cost | 6.5 | 6.6 | 6.7 | 3.2 | 3.3 | 5.1 |
| Expected return on plan assets | (6.8) | (7.1) | (7.1) | (5.0) | (4.7) | (4.6) |
| Amortization of prior service credit | - | - | - | (7.8) | (7.8) | (4.5) |
| Amortization of unrecognized net loss | 0.1 | 0.2 | 0.7 | 0.1 | 0.7 | 1.1 |
| Settlement charge | 0.3 | 4.5 | - | - | - | - |
| Special termination benefit (ERIP) | - | - | 6.0 | - | - | 0.9 |
| Regulatory asset (increase) decrease | - | (1.7) | (4.0) | 5.4 | 5.4 | 7.3 |
| Net periodic pension expense | <u>\$ 3.8</u> | <u>\$ 6.4</u> | <u>\$ 6.7</u> | <u>\$ (3.5)</u> | <u>\$ (2.5)</u> | <u>\$ 6.6</u> |

The decrease in the regulatory asset for PBOP was due primarily to the amortization of costs incurred in prior years. In 2007 and 2006, the regulatory asset for the retirement plans was increased due to the accumulated cost for the year exceeding the expense cap established in the Texas Gas rate case settlement. In accordance with the rate case settlement, Texas Gas is permitted to seek future rate recovery for amounts of annual pension 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 |
|-----------|-----------------------------|-------------|
| 2009 | \$ 4.1 | \$ 4.6 |
| 2010 | 4.3 | 4.3 |
| 2011 | 6.0 | 4.3 |
| 2012 | 9.7 | 4.0 |
| 2013 | 9.8 | 3.9 |
| 2014-2018 | 74.3 | 15.6 |

Weighted –Average Assumptions

The Partnership's asset allocations at December 31, 2008 and 2007, for both the qualified retirement plan and PBOP trusts by category were as follows:

| | Retirement Plans | | PBOP | |
|--|--|-------------|--|-------------|
| | For the Year Ended December 31, | | For the Year Ended December 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| Debt securities | 38% | 46% | 49% | 41% |
| Equity securities | 18% | 23% | 15% | 22% |
| Limited partnerships | 24% | 13% | 26% | 25% |
| Comingled funds | 12% | 12% | 7% | - |
| Cash, short-term investments and other | 8% | 6% | 3% | 12% |
| Total | 100% | 100% | 100% | 100% |

The Partnership employs a total-return approach whereby a mix of equities and fixed income investments is used to maximize the long-term return on plan assets for a prudent level of risk. 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 the financial conditions of the Partnership. The goal for 2008 was to allocate between 40% and 60% of the investment portfolio to equity and alternative investments, including limited partnerships, with consideration given to market conditions and target asset returns. The portion of the portfolio not invested in equity and alternative investments was invested primarily in fixed income securities, comingled funds and the remainder in cash and short-term investments. The investment portfolio contains a diversified blend of U.S. and non-U.S. fixed income and equity investments. Alternative investments, including hedge funds, are used judiciously to enhance risk-adjusted long-term returns while improving portfolio diversification. Derivatives may be used to gain market exposure in an efficient and timely manner. Investment risk is measured and monitored on an ongoing basis through annual liability measurements, periodic asset and liability studies and quarterly investment portfolio reviews.

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2008 and 2007 were the following:

| | Retirement Plans | | PBOP | |
|-------------------------------|--|-------------|--|-------------|
| | For the Year Ended December 31, | | For the Year Ended December 31, | |
| | 2008 | 2007 | 2008 | 2007 |
| Discount rate | 6.30% | 6.00% | 6.30% | 6.00% |
| Rate of compensation increase | 4.00% | 4.00% | - | - |

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

| | Retirement Plans | | | PBOP | | |
|--------------------------------|--|-------------|-------------|--|----------------|----------------|
| | For the Year Ended December 31, | | | For the Year Ended December 31, | | |
| | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Discount rate | 6.00% | 5.94% | 5.63% | 6.00% | 5.75% | 5.63% to 5.75% |
| Expected return on plan assets | 7.50% | 7.50% | 7.50% | 6.15% to 6.15% | 5.00% to 6.15% | 5.00% to 6.15% |
| Rate of compensation increase | 4.00% | 5.50% | 5.50% | - | - | - |

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, 2008 (in millions):

| <u>Effect of 1% Increase:</u> | <u>2008</u> |
|--|--------------------|
| Benefit obligation at end of year | \$ 1.2 |
| Total of service and interest costs for year | 0.1 |
| <u>Effect of 1% Decrease:</u> | |
| Benefit obligation at end of year | \$ (1.4) |
| Total of service and interest costs for year | (0.1) |

For measurement purposes, at December 31, 2008, health care costs for the plans were assumed to increase 9% for 2009-2010 grading down to 5% in 0.5% annual increments for participants not eligible for Medicare and 9.5% grading down to 5% in 0.5% annual increments for participants eligible for Medicare. For December 31, 2007, measurement purposes, health care costs for the plans were assumed to increase 9% for 2008-2009, grading down to 5% in 0.5% annual increments for participants not eligible for Medicare and 10% grading down to 5% in 0.5% annual increments for participants eligible for Medicare.

Defined Contribution Plans

Texas Gas employees hired on or after November 1, 2006 and Gulf South employees are provided retirement benefits under a similar defined contribution money purchase plan. The operating subsidiaries also provide 401(k) plan benefits to their employees. Costs related to the Partnership's defined contribution plans were \$5.7 million, \$5.3 million and \$5.1 million for the years ended December 31, 2008, 2007 and 2006.

Strategic Long-Term Incentive Plan

In 2006, Boardwalk GP approved the Partnership's Strategic Long-Term Incentive Plan (SLTIP). The SLTIP provides for the issuance of up to 500 phantom general partner units (Phantom GP Units) to selected employees of the Partnership and its subsidiaries. The Partnership believes that such awards better align the interests of the selected employees with those of the general partner and common unitholders. Each Phantom GP Unit entitles the holder thereof, upon vesting, to a lump sum cash payment in an amount determined by a formula based on cash distributions made by the Partnership to its general partner during the four quarters preceding the vesting date and the implied yield on the Partnership's common units, up to a maximum of \$50,000 per unit.

A summary of the status of the Partnership's SLTIP as of December 31, 2008, 2007 and 2006, and changes during the years ended December 31, 2008 and 2007, is presented below:

| | <u>Phantom GP Units</u> | <u>Total Fair Value (in millions)</u> | <u>Weighted-Average Vesting Period (in years)</u> |
|-------------------------------|--------------------------------|--|--|
| Outstanding at 12/31/2006 (b) | 250 | \$ 12.5 | 3.5 |
| Granted (a) | 116 | 5.8 | 4.0 |
| Forfeited | (5) | - | - |
| Outstanding at 12/31/2007 (b) | 361 | 18.1 | 3.0 |
| Granted (a) | 125 | 6.3 | 4.0 |
| Paid | (33) | (0.4) | - |
| Forfeited | (76) | - | - |
| Outstanding at 12/31/2008 (b) | 377 | 16.9 | 2.7 |

(a) Represents fair value and weighted-average vesting period of awards at grant date.

- (b) 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 formula contained in the SLTIP and assumptions made regarding potential future cash distributions made to the general partner during the four quarters preceding the vesting date and the future implied yield on the Partnership's common units. 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 prescribed in SFAS No. 123(R). The Partnership recorded \$1.1 million, \$3.3 million and \$0.8 million in Administrative and general expenses during 2008, 2007 and 2006 for the ratable recognition of the GP Phantom Unit awards fair value. The total estimated remaining unrecognized compensation expense related to the GP Phantom Units outstanding at December 31, 2008, of \$12.1 million will be recognized over the average remaining vesting period of approximately 2.7 years. Approximately 90 Phantom GP Units were available for grant under the plan at December 31, 2008.

Long-Term Incentive Plan

In 2005, the Partnership adopted the Long-Term Incentive Plan (LTIP) for the officers and directors of its general partner and for selected employees of its subsidiaries. The Partnership believes that such awards better align the interests of the selected employees with those of the common unitholders. The Partnership reserved 3,525,000 units for grants of units, restricted units, unit options and unit appreciation rights under the plan. The Partnership has granted phantom common units under the plan. Each such grant: includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50% on the second anniversary of the grant date and 50% on the third anniversary of the grant date; and will be payable to the grantee in cash upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date plus the vested amount then credited to the grantee's DER account, less applicable taxes. 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. The Partnership did not make any grants of units, restricted units, unit options or unit appreciation rights under the plan.

A summary of the status of the Partnership's LTIP as of December 31, 2008, 2007 and 2006, and changes during the years ended December 31, 2008 and 2007, is presented below:

| | Phantom Common Units | Total Fair Value (in millions) | Weighted-Average Vesting Period (in years) |
|-------------------------------|---------------------------------|---|---|
| Outstanding at 12/31/2006 (a) | 75,085 | \$ 2.4 | 2.2 |
| Granted (b) | 49,966 | 1.6 | 2.5 |
| Paid | (14,431) | (0.4) | - |
| Forfeited | (2,099) | - | - |
| Outstanding at 12/31/2007 (a) | 108,521 | 3.5 | 1.8 |
| Granted (b) | 54,033 | 1.1 | 2.5 |
| Paid | (32,907) | (0.8) | - |
| Forfeited | (21,359) | - | - |
| Outstanding at 12/31/2008 (a) | 108,288 | 2.1 | 1.8 |

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

- (b) Represents fair value and weighted-average vesting period of awards at grant date.

The fair value of the awards at the date of grant was based on the formula contained in the LTIP, including the closing market price of the Partnership's common units on December 31, 2008, 2007 and 2006, of \$17.78, \$30.62 and \$31.12 plus the accumulated value of 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 prescribed in SFAS No. 123(R). The Partnership recorded \$0.4 million \$1.1 million and \$0.4

million in Administrative and general expenses during 2008, 2007 and 2006 for the ratable recognition of the Phantom Common Unit awards fair value. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2008, of \$1.4 million will be recognized over the average remaining vesting period of approximately 1.8 years.

In 2008 and 2007, the general partner purchased 1,500 of the Partnership's common units each year in the open market at a price of \$23.78 and \$36.61 per unit. These units were granted under the LTIP to the independent directors as part of their director compensation. At December 31, 2008, 3,521,000 units were available for grants under LTIP.

Employee Paid Time-Off Benefits

In fourth quarter 2008, the Partnership consolidated and changed its employee paid time-off benefits. Under the previous plan, employees earned paid time-off benefits in the year prior to the availability of the benefits and allowed some carryover of unused benefits to subsequent years. Under the new plan, employees must use all of the paid time-off in the year it is earned, with the exception of a three year sunset of any carryover existing at December 31, 2008. Due to the nature of the new plan, in the fourth quarter 2008, the Partnership reversed \$7.2 million of its liability associated with amounts that would otherwise have been available to employees as of January 1, 2009, resulting in a reduction to Operation and maintenance expenses of \$4.9 million and Administrative and general expenses of \$2.3 million. The remaining liability of \$2.1 million, which is included in Accrued payroll and employee benefits, is comprised of carryover existing at December 31, 2008.

Note 11: Disposition of Assets

As a result of Phase III the Western Kentucky Storage Expansion approximately 5.1 Bcf of gas was sold, resulting in a gain in 2008 of \$34.4 million including a loss on the settlement of the related derivatives. In 2007, the Partnership recognized a gain of \$22.0 million from the sale of 4.0 Bcf of gas related to sales of base gas from Phase II of the storage expansion project. The gains were included in Net gain on disposal of operating assets and related contracts in the Consolidated Statements of Income.

In 2008, the Partnership completed the sale of its investment in land and coal reserves along the Ohio River in northern Kentucky and southern Indiana for \$16.5 million. These assets had no book value at the time of the sale. As a result, the Partnership recorded a gain of \$16.5 million related to the sale which was reported in Net gain on disposal of operating assets and related contracts in the Consolidated Statements of Income.

Note 12: Net Income per Limited Partner Unit and Cash Distributions

The Partnership calculates net income per limited partner unit in accordance with Emerging Issues Task Force (EITF) Issue No. 03-6, *Participating Securities and the Two-Class Method under FASB Statement No. 128*. In Issue 3 of EITF No. 03-6, the EITF reached a consensus that undistributed earnings for a period should be allocated to a participating security based on the contractual participation rights of the security to share in those earnings as if all of the earnings for the period had been distributed. The Partnership's general partner holds IDRs, which are contractual participation rights as follows:

| | Total Quarterly Distribution | Marginal Percentage Interest in Distributions | |
|----------------------------|-------------------------------------|--|------------------------|
| | | Limited Partner Unitholders (1),(2) | General Partner |
| | Target Amount | | |
| 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% |

- (1) The class B unitholders participate in distributions on a pari passu basis with the Partnership's common units up to \$0.30 per quarter, beginning with the distribution that was made in the fourth quarter 2008. The class B units do not participate in quarterly distributions above \$0.30 per unit.
- (2) The partnership agreement provided that during the subordination period, the subordinated units would not receive distributions until the common and class B unitholders received the respective minimum quarterly distribution (\$0.35 per quarter in the case of common units and \$0.30 in the case of class B units) plus any arrearages. The subordinated units were not entitled to arrearages. In November 2008, the subordinated units converted to common units on a one-for-one basis.

The amounts reported for net income per limited partner unit on the Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006, were adjusted to take into account an assumed allocation to the general partner's IDRs. Payments made on account of the IDRs are determined in relation to actual declared distributions. A reconciliation of the limited partners' interest in net income and net income available to limited partners used in computing net income per limited partner unit follows (in millions, except per unit data):

| | For the Year Ended December 31, | | |
|--|--|-------------|-------------|
| | 2008 | 2007 | 2006 |
| Limited partners' interest in net income | \$ 280.7 | \$ 220.7 | \$ 193.6 |
| Less assumed allocation to IDRs | 4.6 | 4.3 | 5.2 |
| Net income available to limited partners | 276.1 | 216.4 | 188.4 |
| Less assumed allocation to class B units | 13.7 | - | - |
| Less assumed allocation to subordinated units | 56.6 | 61.9 | 61.1 |
| Net income available to common units | \$ 205.8 | \$ 154.5 | \$ 127.3 |
| Weighted-average common units (a) | 104.2 | 82.5 | 69.0 |
| Weighted-average class B units (b) | 22.9 | - | - |
| Weighted-average subordinated units (a) | 28.7 | 33.1 | 33.1 |
| Net income per limited partner unit – common units | \$ 1.98 | \$ 1.87 | \$ 1.85 |
| Net income per limited partner unit – class B units | \$ 0.60 | \$ - | \$ - |
| Net income per limited partner unit – subordinated units | \$ 1.98 | \$ 1.87 | \$ 1.85 |

- (a) All of the 33.1 million subordinated units converted to common units on a one-for-one basis in November 2008.
- (b) The number of class B units shown is weighted from July 1, 2008, which is the date they became eligible to participate in earnings.

As discussed in Note 7, the class B units were not eligible to participate in income allocations until third quarter 2008. As a result, no income allocations were made to the class B unit equity accounts and no assumed allocations to the class B units were made pursuant to EITF No. 03-6 for purpose of computing earnings per unit

prior to July 1, 2008.

The Partnership has declared quarterly distributions per unit to partners of record, including holders of common, subordinated and class B units 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 and Subordinated Unitholders (a) | Amount Paid to Class B Unitholder | Amount Paid to General Partner (Including IDRs) (b) |
|---------------------|----------------------------------|---|--|--|
| November 10, 2008 | \$ 0.475 | \$ 63.6 | \$ 6.9 | \$ 3.7 |
| August 11, 2008 | 0.470 | 62.8 | - | 3.4 |
| May 12, 2008 | 0.465 | 57.6 | - | 2.9 |
| February 25, 2008 | 0.460 | 56.9 | - | 2.7 |
| November 12, 2007 | 0.450 | 52.3 | - | 2.2 |
| August 13, 2007 | 0.440 | 51.1 | - | 1.7 |
| May 14, 2007 | 0.430 | 50.1 | - | 1.5 |
| February 27, 2007 | 0.415 | 44.9 | - | 1.2 |
| November 6, 2006 | 0.400 | 40.5 | - | 0.8 |
| August 18, 2006 | 0.380 | 38.5 | - | 0.8 |
| May 19, 2006 | 0.360 | 36.5 | - | 0.8 |
| February 23, 2006 | 0.179 (c) | 18.1 | - | 0.4 |

- (a) All of the 33.1 million subordinated units converted to common units on a one-for-one basis two days following the November 10, 2008 distribution.
- (b) In 2008 and 2007, the Partnership paid \$7.5 million and \$2.5 million in distributions on behalf of IDRs. There were no amounts paid on behalf of IDRs in 2006.
- (c) Distribution represented a prorated portion of the \$0.350 per unit “minimum quarterly distribution” (as defined in the Partnership’s partnership agreement) for the period November 15, 2005 through December 31, 2005.

In February 2009, the Partnership declared a quarterly cash distribution to unitholders of record of \$0.48 per unit.

Note 13: Income Tax

In July 2006, the FASB issued Interpretation No. (FIN) 48, *Accounting for Uncertainty in Income Taxes - An Interpretation of FASB Statement No. 109*, which is effective for the Partnership's year beginning January 1, 2007. This interpretation was issued to clarify the accounting for uncertainty in income taxes recognized in the financial statements by prescribing a comprehensive model for how a company should recognize, measure, present, and disclose uncertain tax positions taken or expected to be taken in a tax return. The Partnership has determined that FIN 48 does not have an impact on its results of operations.

Following is a summary of the provision for income taxes for the periods ended December 31, 2008, 2007 and 2006 (in millions):

| | For the Year Ended December 31, | | |
|---------------------|---------------------------------|--------|--------|
| | 2008 | 2007 | 2006 |
| Current expense: | | | |
| State | \$ 0.7 | \$ 0.8 | \$ 0.2 |
| Total | 0.7 | 0.8 | 0.2 |
| Deferred provision: | | | |
| State | 0.3 | - | - |
| Total | 0.3 | - | - |
| Income taxes | \$ 1.0 | \$ 0.8 | \$ 0.2 |

The Partnership's tax years 2005 through 2007 remain subject to examination by the Internal Revenue Service and the states in which it operates. There were no differences between the provision at statutory rate to the income tax provision at December 31, 2008, 2007 and 2006. As of December 31, 2008 and 2007, there were no significant deferred income tax assets or liabilities.

Note 14: Financial Instruments

The following methods and assumptions were used in estimating the Partnership's fair-value disclosures for financial instruments:

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

Short-term investments: In December 2008, the Partnership began investing a portion of its undistributed cash in U.S. Government securities, primarily Treasury notes, under repurchase agreements. Generally, the Partnership has engaged in overnight repurchase transactions where purchased securities are sold back to the counterparty the following business day. Pursuant to the master repurchase agreements, the Partnership takes actual possession of the purchased securities. In the event of default by the counterparty under the agreement, the repurchase would be deemed immediately to occur and the Partnership would be entitled to sell the securities in the open market, or give the counterparty credit based on the market price on such date, and apply the proceeds (or deemed proceeds) to the aggregate unpaid repurchase amounts and any other amounts owing by the counterparty.

At December 31, 2008, the portfolio consisted of \$175.0 million of Treasury securities with original maturities in August 2009, held pursuant to overnight repurchase agreements. The amount invested under repurchase agreements was stated at fair value based on quoted market prices for the securities.

Long-Term Debt: Except for debt issued by Gulf South, the debt issued by Texas Gas in March 2008 and the revolving credit facility, all of the Partnership's long-term debt is publicly traded. The estimated fair value of the Partnership's publicly traded debt is based on quoted market prices at December 31, 2008 and 2007. The fair market

value of the debt that is not publicly traded and the revolving credit facility is based on market prices of similar debt at December 31, 2008 and 2007.

The carrying amount and estimated fair values of the Partnership's financial instruments as of December 31, 2008 and 2007 were as follows (in millions):

| | 2008 | | 2007 | |
|------------------------------|-----------------|------------|-----------------|------------|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Financial Assets | | | | |
| Cash and cash equivalents | \$ 137.7 | \$ 137.7 | \$ 317.3 | \$ 317.3 |
| Short-term investments | 175.0 | 175.0 | - | - |
| Financial Liabilities | | | | |
| Long-term debt | \$ 2,889.4 | \$ 2,655.3 | \$ 1,847.9 | \$ 1,834.2 |

Note 15: Accumulated Other Comprehensive Income (Loss)

The following table shows the components of Accumulated other comprehensive (loss) income, net of tax which is included in Partners' Capital on the Consolidated Balance Sheets (in millions):

| | For the Year Ended December 31, | |
|---|------------------------------------|----------|
| | 2008 | 2007 |
| Loss on cash flow hedges, net of tax | \$ (0.7) | \$ (8.9) |
| Deferred components of net periodic benefit cost, net of tax | (14.8) | 13.1 |
| Total Accumulated other comprehensive (loss) income, net of tax | \$ (15.5) | \$ 4.2 |

In 2009, the Partnership expects to recognize \$13.6 million of the amounts shown above in earnings. This amount is comprised of increases to earnings of \$9.3 million related to cash flow hedges and \$4.3 million related to net periodic benefit cost.

Note 16: Major Customers

Major Customers

Operating revenues received from the Partnership's major customer (in millions) and the percentage of Total operating revenues earned from that customer were:

| Customer | For the Year Ended December 31, | | | | | |
|--------------|---------------------------------|----|---------|-----|---------|----|
| | 2008 | | 2007 | | 2006 | |
| | Revenue | % | Revenue | % | Revenue | % |
| Atmos Energy | \$ 73.0 | 9% | \$ 63.9 | 10% | \$ 56.4 | 9% |

Natural gas price volatility has increased dramatically in recent years, which has materially increased changes in credit risk related to gas loaned to customers. As of December 31, 2008, the amount of gas loaned by the operating subsidiaries or owed to the operating subsidiaries due to gas imbalances was approximately 34.4 TBtu. Assuming an average market price during December 2008 of \$5.85 per million British thermal units, the market value of that gas was approximately \$201.2 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, this could have a material adverse effect on the Partnership's financial condition, results of operations and cash flows.

Note 17: Related Party Transactions

Loews provides a variety of corporate services to the Partnership and its subsidiaries under services agreements which have been operative since the Partnership's initial public offering. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged \$14.5 million, \$12.1 million, and \$13.0 million for the years ended December 31, 2008, 2007 and 2006 to the Partnership based on the actual time spent by Loews personnel performing these services, plus related expenses.

Distributions paid related to limited partner units held by BPHC, the 2% general partner interest and IDRs held by Boardwalk GP were \$181.1 million, \$156.4 million and \$116.6 million for 2008, 2007 and 2006.

As discussed in Note 7, the Partnership issued 22.9 million class B units and 21.2 million common units to BPHC in 2008 resulting in net proceeds of \$1.2 billion, including contributions from the general partner to maintain its 2% interest.

Note 18: Recently Issued Accounting Pronouncements

In March 2008, the FASB approved EITF Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships*, which requires that master limited partnerships use the two-class method of allocating earnings to calculate earnings per unit. EITF Issue No. 07-4 is effective for fiscal years and interim periods beginning after December 15, 2008. The Partnership is evaluating the effect that EITF Issue No. 07-4 will have on its earnings per unit and financial statements.

Note 19: Supplemental Disclosure of Cash Flow Information (in millions):

| | For the Year Ended December 31, | | |
|--------------------------------------|--|----------|---------|
| | 2008 | 2007 | 2006 |
| Cash paid during the period for: | | | |
| Interest (net of amount capitalized) | \$ 115.4 | \$ 46.1 | \$ 58.1 |
| Income taxes, net | 0.8 | 0.3 | 0.2 |
| Non-cash adjustments: | | | |
| Accounts payable and PPE | \$ 86.8 | \$ 175.8 | \$ 31.9 |
| Accrued registration rights costs | 20.6 | - | - |

Note 20: Selected Quarterly Financial Data (Unaudited)

The following tables summarize selected quarterly financial data for 2008 and 2007 for the Partnership (in millions, except for earnings per unit):

| 2008 | | | | |
|-------------------------------|--------------------|---------------------|----------------|-----------------|
| For the Quarter Ended: | | | | |
| | December 31 | September 30 | June 30 | March 31 |
| Operating revenues | \$ 205.6 | \$ 191.6 | \$ 190.3 | \$ 197.3 |
| Operating expenses | 130.3 | 102.8 | 109.3 | 95.8 |
| Operating income | 75.3 | 88.8 | 81.0 | 101.5 |
| Interest expense, net | 10.9 | 8.6 | 17.3 | 18.0 |
| Other (income) expense | (3.4) | 6.3 | (1.2) | (4.9) |
| Income before income taxes | 67.8 | 73.9 | 64.9 | 88.4 |
| Income taxes | 0.2 | 0.3 | 0.2 | 0.3 |
| Net income | \$ 67.6 | \$ 73.6 | \$ 64.7 | \$ 88.1 |
| Earnings per unit: | | | | |
| Common units | \$ 0.40 | \$ 0.47 | \$ 0.49 | \$ 0.60 |
| Class B units | \$ 0.30 | \$ 0.30 | \$ - | \$ - |
| Subordinated units | \$ 0.40 | \$ 0.47 | \$ 0.49 | \$ 0.60 |

| 2007 | | | | |
|-------------------------------|--------------------|---------------------|----------------|-----------------|
| For the Quarter Ended: | | | | |
| | December 31 | September 30 | June 30 | March 31 |
| Operating revenues | \$ 169.8 | \$ 134.8 | \$ 150.5 | \$ 188.1 |
| Operating expenses | 89.0 | 86.2 | 106.2 | 95.8 |
| Operating income | 80.8 | 48.6 | 44.3 | 92.3 |
| Interest expense, net | 9.7 | 9.0 | 8.6 | 12.2 |
| Other (income) expense | (1.3) | (0.5) | 0.1 | (0.3) |
| Income before income taxes | 72.4 | 40.1 | 35.6 | 80.4 |
| Income taxes | 0.3 | 0.1 | 0.2 | 0.2 |
| Net income | \$ 72.1 | \$ 40.0 | \$ 35.4 | \$ 80.2 |
| Earnings per unit: | | | | |
| Common units | \$ 0.56 | \$ 0.35 | \$ 0.35 | \$ 0.61 |
| Subordinated units | \$ 0.56 | \$ 0.30 | \$ 0.17 | \$ 0.61 |

Note 21: Guarantee of Securities of Subsidiaries

The Partnership has no independent assets or operations other than its investment in its subsidiaries. The Partnership's Boardwalk Pipelines subsidiary has issued securities which have been fully and unconditionally guaranteed by the Partnership. All of the subsidiaries of the Partnership are minor other than Boardwalk Pipelines and its consolidated subsidiaries. The Partnership does have separate partners' capital including publicly traded limited partner common units.

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, 2008. Note 7 contains additional information regarding the Partnership's debt and related covenants.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures as of the end of the period covered by this report. The CEO and CFO have concluded that our controls and procedures were effective as of December 31, 2008.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2008, 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, 2008. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*. Based on this assessment, our management believes that, as of December 31, 2008, 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, 2008, based on criteria established in *Internal Control—Integrated Framework* 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, 2008, based on the criteria established in *Internal Control—Integrated Framework* 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 and financial statement schedule as of and for the year ended December 31, 2008 of the Partnership and our report dated February 24, 2009 expressed an unqualified opinion on those financial statements and financial statement schedule.

DELOITTE & TOUCHE LLP
Houston, Texas
February 24, 2009

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

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 to cause us to incur indebtedness or other obligations that are nonrecourse to it. 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.

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 which are made in its individual capacity will be made by BPHC, the sole member of BGL, rather than by our Board.

Directors and Executive Officers

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

| <u>Name</u> | <u>Age</u> | <u>Position</u> |
|-----------------------|------------|--|
| Rolf A. Gafvert | 55 | Chief Executive Officer, President and Director |
| Jamie L. Buskill | 44 | Chief Financial Officer, Senior Vice President and Treasurer |
| Brian A. Cody | 51 | Chief Operating Officer |
| Michael E. McMahon | 53 | Senior Vice President, General Counsel and Secretary |
| Arthur L. Rebell | 68 | Director, Chairman of the Board |
| William R. Cordes | 60 | Director |
| Thomas E. Hyland | 63 | Director |
| Jonathan E. Nathanson | 47 | Director |
| Mark L. Shapiro | 64 | Director |
| Andrew H. Tisch | 59 | Director |

All directors have served since 2005 except for Mr. Cordes who was elected to the Board in October 2006. All directors serve until replaced or upon their voluntary resignation.

Rolf A. Gafvert—Mr. Gafvert has been the Chief Executive Officer of BGL since February 2007 and President since February 2008. Prior thereto he had been the Co-President of BGL since its inception in 2005. Mr. Gafvert has been the President of Gulf South since 2000 and has been employed by Gulf South or its predecessors since 1993. During that time he also served in various management roles for affiliates of Gulf South, including President of Koch Power, Inc., Managing Director of Koch Energy International and Vice President of Corporate Development

for Koch Energy, Inc. Mr. Gafvert is on the Board of Directors of the Interstate Natural Gas Association of America.

Jamie L. Buskill—Mr. Buskill has been the Chief Financial Officer 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 is a member of the Southern Gas Association Accounting and Finance Committee and serves on the board of various charitable organizations.

Brian A. Cody—In February 2009, Mr. Cody was appointed Chief Operating Officer of BGL. Prior to the appointment, Mr. Cody had been the Chief Commercial Officer of BGL since March 2007. Mr. Cody has served in various management roles for Gulf South including: Vice President of Business Development from 2006 to 2007, Chief Financial Officer from 2005 to 2006, Vice President of Long-Term Marketing from 2003 to 2005 and Controller from 2000 to 2003. He has been employed by Gulf South or its predecessors since 1987 and is a Certified Public Accountant.

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 committees of Interstate Natural Gas Association of America and the American Gas Association.

Arthur L. Rebell—Mr. Rebell is a Senior Vice President at Loews. He has been employed by Loews in that capacity since 1998 and has been primarily responsible for investments, corporate strategy, mergers and acquisitions and corporate finance. Mr. Rebell also serves as a director for Diamond Offshore Drilling, Inc., a subsidiary of Loews.

William R. Cordes—Mr. Cordes retired as President of Northern Border Pipeline Company in April 2007. Prior to his retirement, he had worked in the natural gas industry for more than 35 years, including as Chief Executive Officer of Northern Border Partners, LP and President of Northern Natural Gas Company and Transwestern Pipeline Company. Mr. Cordes is also a member of the Board for the Kayne Anderson Energy Development Fund. Mr. Cordes is currently a private investor.

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 is currently a private investor.

Jonathan E. Nathanson—Mr. Nathanson is Vice President—Corporate Development of Loews. He has been employed by Loews in that capacity since 2001 and is responsible for mergers and acquisitions and corporate finance.

Mark L. Shapiro—Mr. Shapiro has been a private investor since 1998. Mr. Shapiro also serves as a director for W.R.Berkley Corporation.

Andrew H. Tisch—Mr. Tisch has been Co-Chairman of the Board of Loews since January 2006 and is the Chairman of the Executive Committee and a member of the Office of the President of Loews. He has served as 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.

Our Independent Directors

Our Board has determined that Thomas E. Hyland, Mark L. Shapiro and William R. Cordes are independent directors under the listing standards of the New York Stock Exchange (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 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 has appointed an Audit Committee 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 have a majority of independent directors on its board of directors or to maintain a compensation or nominating/corporate governance committee. In reliance on these exemptions, our Board is not comprised of a majority of independent directors, and we do not maintain a compensation or nominating/corporate governance committee.

Audit Committee

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 Securities and Exchange Commission (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. The Chairman of the Audit Committee and the Chairman of the Conflicts Committee alternate serving as the presiding director at these meetings.

Corporate Governance Guidelines and Code of Conduct

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 on our website. 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 2008, in a timely manner.

Item 11. Executive Compensation

Compensation Discussion and Analysis

Overview

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 the Partnership and our unitholders, including maintaining current levels of unitholder distributions and taking prudent steps to grow unitholder distributions. To meet this objective we have established a compensation policy for our executive officers which combines elements of base salary and cash and equity-based incentive compensation, as well as retirement and other benefits. We have selected these elements and otherwise structured our executive compensation practices to align the interests of our executives with those of our unitholders and our general partner, retain our executives and appropriately reward their performance both in the long and short-term. At the time of our initial public offering in 2005, we considered the executive compensation programs of various companies engaged in similar businesses with similar corporate structures in the initial development of our compensation programs, particularly with regard to the development of our equity-based compensation plans. We considered those programs to obtain a general understanding of then-current compensation practices and industry trends. We also considered the historical compensation policies and practices of our operating subsidiaries, as well as applicable tax and accounting impacts of executive compensation, including the tax implications of providing equity-based compensation to our employees in light of our being a limited partnership. In developing our compensation plans, no benchmarking of total compensation, or any element of compensation, was performed against any particular reference group of companies.

As discussed elsewhere in this Report, our Board of Directors (Board) does not have a Compensation Committee. Therefore, the compensation for Rolf Gafvert, our Chief Executive Officer (CEO) (principal executive officer (PEO)), Jamie L. Buskill, our Chief Financial Officer (CFO) (principal financial officer (PFO)) and our three other most highly compensated executive officers (together with our former Senior Vice President of Operations, John C. Earley, Jr., who resigned as an officer in conjunction with his termination of employment with the Partnership in May 2008), our “Named Executive Officers,” is reviewed with and is subject to the approval of our entire Board, with Mr. Gafvert not participating in those Board discussions with respect to his own compensation.

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

- base salary;
- annual incentive compensation awards, including cash bonuses and grants of phantom common units (Phantom Common Units) under our Long-Term Incentive Plan (LTIP);
- annual grants of phantom general partner units (Phantom GP Units) under our Strategic Long-Term Incentive Plan (SLTIP); and
- retirement, medical and related benefits.

As discussed in more detail below, in setting compensation policies and making compensation decisions for our Named Executive Officers, our Board typically considers certain financial measures, operating goals and progress made on key projects. However, we do not rely on formula-driven plans when determining the aggregate amount of compensation for each Named Executive Officer. Our Board considers a number of factors in making its determinations of executive compensation, including compensation paid in prior years, whether the financial measures, operating goals and project progress were achieved and the individual contributions of each executive to our overall business success for the year. However, the final amount of any payout is discretionary, is based on judgment and is not generated or calculated by reference to any particular performance metric.

Base Salary

Our executive compensation policies emphasize the incentive-based compensation elements discussed below. In determining the amount of base salary, the Board generally takes into consideration the responsibilities of each Named Executive Officer and determines compensation appropriate for the positions held and services to be rendered during the year. In 2008, the base salary of Mr. Buskill was increased approximately 30% reflecting his commitment to relocate his primary office to Houston, Texas. The base salaries of our other Named Executive Officers were increased modestly based on individual merit, in amounts ranging from 1% to 7%. These increases were determined through discussions between Mr. Gafvert and the Chairman of the Board, and were thereafter presented to and approved by the Board.

Incentive Compensation – Cash Bonuses and Phantom Common Unit Awards

Our incentive compensation programs, and the compensation awarded under them, are discretionary and are not formulaic in nature. In the context of performance and past compensation policies and practices, the Board considers individual performance factors that include the Board's view of the performance of the individual, the responsibilities of the individual's position and the individual's contribution to the Partnership and to the financial and operational performance for the most recently completed fiscal year. There is no specific weighting given to each factor, but rather the Board considers and balances these factors in its judgment and discretion.

Cash Bonuses. A significant portion of the compensation of our Named Executive Officers consists of an annual incentive compensation award, which is an aggregate dollar amount determined by our Board that is paid in part as a cash bonus and in part as an award of Phantom Common Units. In order to balance our goals of motivating our Named Executive Officers to achieve long-term results for our unitholders and providing them with appropriate current cash compensation, our general guideline is to award approximately three-fourths of any annual incentive compensation as a cash bonus and one-fourth as an award of Phantom Common Units, though the Board retains discretion in making this determination.

At the beginning of a year, the Board establishes, based upon a recommendation by the CEO, a potential bonus pool for our employees as a whole, including the Named Executive Officers. Certain financial or operating measures are established by the Board to be used as guidelines in determining, at year end, the final amount of the pool and individual bonus awards. These measures are not firm targets or goals that must be achieved in order for payouts from the bonus pool to be made; rather the Board considers these measures, based upon recommendations by the CEO, in determining whether to adjust the size of the bonus pool at the end of the year and in awarding individual payments from the pool. At the end of the year, the CEO makes recommendations to the Board regarding the size of the final bonus pool and amounts to pay Named Executive Officers and other employees, taking into consideration actual results as compared to the measures set at the beginning of the year, the individual performance and contributions to the Partnership of each Named Executive Officer and other factors deemed relevant. The amounts of the bonus pool and any individual awards are discretionary based on the judgment of the CEO and the Board. Any bonus paid to the CEO is determined by the Board based upon a similar review of his performance and contributions.

For 2008, the financial and operating measures that were established by the Board were:

- Achieving 2008 EBITDA, as defined in Item 6, *Non-GAAP Financial Measure*, adjusted for expected unusual items, of \$415.8 million and annual distributions with respect to 2008 of \$1.89 per unit;
- Operating a safe, reliable pipeline system;
- Timely completion of our announced pipeline expansion projects within budget; and
- Contracting the available capacity of our expansion projects and renegotiating or replacing expiring contracts on our existing pipelines for longer terms and at favorable rates.

For 2008, the Board determined that we met most, but not all of our financial and operational goals. For example, our Gulf Crossing Pipeline project and Fayetteville and Greenville Laterals were not placed in service when initially projected. In addition, certain executives who were employed by us at the beginning of 2008 were no

longer employed, and therefore not eligible for incentive compensation, at the end of the year. As a result, the Board decided to reduce the bonus pool from the target amount established at the beginning of the year. In making that decision, our CEO and the Board considered the factors listed above, with particular emphasis on the contributions made during the year by the individual Named Executive Officers to the success of the expansion projects we have undertaken, which are more fully described in Part I, Item I of this Report. The amounts awarded to the Named Executive Officers are set forth in the Summary Compensation Table below.

Phantom Common Unit Awards. We are a limited partnership. If our Named Executive Officers owned our units directly, they would be subject to significant adverse individual tax consequences, such as being taxed on all income as partners rather than employees. Furthermore, the ownership of units by our executives would negatively impact the tax status of our benefit plans. As a result, we award our executives equity-based compensation in the form of Phantom Common Units. The economic value of these awards is directly tied to the value of our common units, but these awards do not confer any rights of ownership to the grantee. The value of a Phantom Common Unit is equal to the value of a common unit plus accumulated distributions made on such common unit since the award date. That value is paid to the executive by us in cash at the end of a vesting period if the executive is still employed on the vesting date. Our Board has discretion to determine the amount, vesting schedule and certain other terms of awards under our LTIP.

The number of Phantom Common Units awarded to a Named Executive Officer is determined by dividing the dollar amount of such executive's incentive based compensation that has been allocated to such an award by the closing price of our common units on the New York Stock Exchange (NYSE) on the date of grant. For example, if an executive is awarded \$250,000 of incentive compensation, of which \$60,000 is designated for an award of Phantom Common Units (the balance being paid as a cash bonus), and the closing price of our common units on the NYSE on the grant date is \$30.00 per unit, the executive would be awarded 2,000 Phantom Common Units for that year.

The Phantom Common Units awarded to our Named Executive Officers vest 50% on the second anniversary of the grant date and 50% on the third anniversary of the grant date, and become payable in cash upon vesting. Since the value of the Phantom Common Units is tied directly to the price of our common units, and the amount of distributions made on those units during the vesting period, this element of compensation directly aligns the interests of our Named Executive Officers with those of our common unitholders and promotes retention.

Phantom GP Units. Our Board has also made awards of Phantom GP Units to our Named Executive Officers. These awards give the grantee an economic interest in the performance of our general partner, including our general partner's incentive distribution rights, but do not confer any right of ownership of our general partner to the grantee. Phantom GP Units provide the holder with an opportunity, subject to vesting, to receive a lump sum cash payment in an amount determined under a formula based on the amount of cash distributions made by us to our general partner during the four quarters preceding the vesting date and the implied yield on our common units, up to a maximum of \$50,000 per unit.

These awards recognize and reward our Named Executive Officers based on our long-term performance and encourage them to continue their employment with us since any awards would be forfeited if the executive is not employed by us on the vesting date. They also encourage our Named Executive Officers to carefully focus on long-term returns to unitholders and our general partner when making management decisions. The value of these awards is impacted by our performance, the value of our common units and the distributions made to our general partner. Therefore, these awards further align the interests of our Named Executive Officers with those of our unitholders.

We awarded an aggregate of 125 Phantom GP Units in December 2008, which vest in 4 years, to 21 of our key employees, of which 61 were awarded to our Named Executive Officers. In making these awards, our Board considered each grantee's overall performance, with particular emphasis on the contributions made by the individual executive to our expansion projects, among other strategic goals and objectives.

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. Certain Named Executive Officers participate in a defined contribution money purchase plan available to employees of Gulf South, while others participate in a defined benefit cash balance pension plan available to employees of Texas Gas hired prior to November 1, 2006, which includes a non-qualified restoration plan for amounts earned in excess of IRC limits for qualified retirement plans. Certain Named Executive Officers are also eligible for retiree medical benefits after reaching age 55 as part of a plan offered to Texas Gas employees.

Equity Ownership Guidelines

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

All Other Compensation

In 2008, Mr. Earley terminated his employment with the Partnership. In connection with Mr. Earley's resignation, we agreed to pay a sum of \$1,550,000 including \$665,855 relating to our agreement to accelerate the vesting of equity compensation benefits as consideration for his covenants, waivers and releases as described in his separation agreement. In addition, Mr. Earley entered into a consulting services agreement with us for a period of six months beginning in May 2008, for which we paid him \$16,667 per month. There were no other material perquisites or personal benefits paid to our Named Executive Officers.

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 annual report on Form 10-K.

By the members of the Board of Directors:

William R. Cordes
Rolf A. Gafvert
Thomas E. Hyland
Jonathon E. Nathanson
Arthur L. Rebell, Chairman
Mark L. Shapiro
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. Gafvert, have been or are officers or employees of us or our subsidiaries. Mr. Gafvert 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 executive officers served as 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 2008, 2007 or 2006.

Executive Compensation

Summary of Executive Compensation

The following table shows a summary of total compensation earned by our Named Executive Officers during 2008, 2007 and 2006:

| Summary Compensation Table for 2008 | | | | | | | |
|--|------|------------|------------|------------------|---|------------------------|--------------|
| Name and Principal Position | Year | Salary | Bonus | Stock Awards (1) | Change in Pension Value and Nonqualified Deferred Compensation Earnings | All Other Compensation | Total |
| Rolf A. Gafvert, CEO (PEO) | | | | | | | |
| | 2008 | \$ 325,000 | \$ 300,000 | \$ 1,087,140 | - | \$ 33,589 (2) | \$ 1,745,729 |
| | 2007 | 323,365 | 300,000 | 857,917 | - | 35,360 | 1,516,642 |
| | 2006 | 240,000 | 300,000 | 296,386 | - | 32,149 | 868,535 |
| Jamie L. Buskill, CFO (PFO) | | | | | | | |
| | 2008 | 292,500 | 150,000 | 461,116 | \$ 43,464 (3) | 23,934 (4) | 971,014 |
| | 2007 | 225,000 | 225,000 | 338,771 | 46,602 | 14,386 | 849,759 |
| | 2006 | 225,000 | 100,000 | 113,207 | 40,333 | 14,292 | 492,832 |
| Brian A. Cody, Chief Commercial Officer | | | | | | | |
| | 2008 | 240,000 | 200,000 | 496,770 | - | 27,615 (5) | 964,385 |
| | 2007 | 228,846 | 175,000 | 423,425 | - | 23,107 | 850,378 |
| John C. Earley, Jr., Senior VP of Operations | | | | | | | |
| | 2008 | 92,308 | - | 153,543 | - | 1,017,876 (6) | 1,263,727 |
| | 2007 | 226,154 | 175,000 | 399,563 | - | 23,681 | 824,398 |
| Michael E. McMahon, Senior VP, General Counsel and Secretary | | | | | | | |
| | 2008 | 230,769 | 200,000 | 418,198 | - | 20,666 (7) | 869,633 |
| | 2007 | 216,346 | 125,000 | 356,833 | - | 28,938 | 727,117 |

- (1) Represents compensation expense accrued for 2008, 2007 and 2006 related to Phantom Common Units and Phantom GP Units granted in 2008, 2007 and 2006. The accruals were made pursuant to SFAS No. 123(R), *Share Based Payments*. See the Grants of Plan-Based Awards table presented below for further information.
- (2) Includes matching contributions under 401(k) plan (\$13,800), employer contributions to the Gulf South Money Purchase Plan, imputed life insurance premiums, club memberships, spouse travel, preferred parking and sporting event tickets.
- (3) Includes the change in qualified retirement plan account balance (\$12,272) and interest and pay credits for the supplemental retirement plan (\$31,192).
- (4) Includes matching contributions under 401(k) plan (\$13,800), moving expenses, imputed life insurance premiums and preferred parking.
- (5) Includes matching contributions under 401(k) plan (\$13,050), employer contributions to the Gulf South Money Purchase Plan, imputed life insurance premiums, spouse travel, preferred parking and travel clubs.
- (6) Mr. Earley's employment terminated on May 7, 2008. His other compensation includes payment for covenant consideration in connection with his separation from the Partnership (\$884,145), payment for post-employment consulting services (\$100,000), matching contributions under 401(k) plan (\$13,800), COBRA coverage, employer contributions to the Gulf South Money Purchase Plan, spouse travel, imputed life insurance premiums and preferred parking.
- (7) Includes employer contributions to the Gulf South Money Purchase Plan, matching contributions under 401(k) plan, imputed life insurance premiums, spouse travel, preferred parking, sporting event tickets and travel clubs.

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 Salary and Bonus Paid to Total Compensation |
|--------------------------------|-------------|--|
| Rolf A. Gafvert | 2008 | 36% |
| | 2007 | 41% |
| | 2006 | 62% |
| Jamie L. Buskill | 2008 | 46% |
| | 2007 | 53% |
| | 2006 | 66% |
| Brian A. Cody | 2008 | 44% |
| | 2007 | 47% |
| John C. Earley, Jr. | 2008 | 7% |
| | 2007 | 49% |
| Michael E. McMahon | 2008 | 47% |
| | 2007 | 47% |

Grants of Plan-Based Awards

The following table displays information regarding grants during 2008 to our Named Executive Officers of plan-based awards, including Phantom GP Unit awards under our SLTIP and Phantom Common Unit awards under our LTIP:

| Grants of Plan-Based Awards for 2008 | | | | | |
|---|-------------------|--|--|---|---|
| Names | Grant Date | All Other Stock Awards: Number of Shares of Stock or Units (1), (2) (#) | All Other Options Awards: Number of Securities Underlying Options (#) | Exercise or Base Price of Option Awards (\$) | Grant Date Fair Value of Stock and Option Awards (1), (2) (\$) |
| Rolf A. Gafvert | 12/16/08 | 8,740 | - | - | 1,425,000 |
| Jamie L. Buskill | 12/16/08 | 3,747 | - | - | 675,000 |
| Brian A. Cody | 12/16/08 | 3,747 | - | - | 675,000 |
| John C. Earley, Jr. | - | - | - | - | 166,812 (3) |
| Michael E. McMahon | 12/16/08 | 2,502 | - | - | 650,000 |

- (1) On July 24, 2006, our SLTIP became effective. The plan provides for the issuance of up to 500 Phantom GP Units to our key employees. Each Phantom GP Unit entitles the holder thereof, upon vesting, to a lump sum cash payment in an amount determined by a formula based on cash distributions made by us to our general partner during the four quarters preceding the vesting date and the implied yield on our common units, up to a maximum of \$50,000 per unit. On December 16, 2008, Messrs. Gafvert, Buskill, Cody and McMahon were awarded 25, 12, 12, and 12 Phantom GP Units that have a 4.0 year vesting period. The fair value of the awards was determined as of the date of grant and will be remeasured each quarter until settlement in accordance with the treatment of awards classified as liabilities prescribed in SFAS No. 123(R). The fair value at grant date of the December 16, 2008, grants was \$50,000 per GP Phantom Unit. The fair value of the awards will be recognized ratably over the vesting period. See footnote (2) to the Outstanding Equity Awards at December 31, 2008 table presented below. Note 10 in Item 8 of this Report contains more information regarding our SLTIP.

- (2) On December 16, 2008, Messrs. Gafvert, Buskill, Cody and McMahon were awarded 8,715, 3,735, 3,735 and 2,490 Phantom Common Units. The closing price of our common units on the date of grant on the NYSE for 2008 was \$20.08, from which the fair value of the units was derived. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50% on the second anniversary of the grant date and 50% on the third anniversary of the grant date; and will be payable to the grantee in cash upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date plus the vested amount then credited to the grantee's DER account, less applicable taxes. Note 10 in Item 8 of this Report contains more information regarding our LTIP.
- (3) In conjunction with Mr. Earley's resignation, the vesting of equity compensation benefits was accelerated. This amount represents the incremental amount recognized in the financial statements in accordance with SFAS No. 123(R) related to the accelerated vesting.

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

For more information about the components of compensation reported in the Summary Compensation Table, please read the "Compensation Discussion and Analysis," above. We do not have employment agreements with any of our Named Executive Officers.

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 and Phantom GP Units awarded under our SLTIP and held by our Named Executive Officers at December 31, 2008:

| Outstanding Equity Awards at December 31, 2008 | | | | | |
|---|-------|--|--|--|---|
| | | Stock Awards | | | |
| Name | | Number of Shares or Units of Stock that Have Not Vested (1) (#) | Market Value of Shares or Units of Stock that Have Not Vested (2)(3) (\$) | Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights that Have Not Vested (#) | Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Rights that Have Not Vested (\$) |
| | | | | | |
| Rolf A. Gafvert | LTIP | 18,460 | 328,219 | - | - |
| | SLTIP | 100 | 995,164 | - | - |
| Jamie L. Buskill | LTIP | 4,337 | 77,112 | - | - |
| | SLTIP | 46 | 452,679 | - | - |
| Brian A. Cody | LTIP | 8,607 | 153,032 | - | - |
| | SLTIP | 49 | 490,179 | - | - |
| John C. Earley, Jr. (4) | LTIP | - | - | - | - |
| | SLTIP | - | - | - | - |
| Michael E. McMahon | LTIP | 7,362 | 130,896 | - | - |
| | SLTIP | 43 | 411,607 | - | - |

- (1) On December 16, 2008, Messrs. Gafvert, Buskill, Cody, and McMahon were awarded grants of Phantom Common Units under our LTIP of 8,715, 3,735, 3,735 and 2,490 and Phantom GP Units under our SLTIP in the amount of 25, 12, 12, and 12. On December 14, 2007, Messrs. Gafvert, Buskill, Cody, Earley and McMahon were awarded grants of Phantom Common Units under our LTIP of 6,532, 0, 3,266, 3,266 and 3,266 and Phantom GP Units under our SLTIP in the amount of 25, 12, 10, 9 and 12. On December 20, 2006, Messrs. Gafvert and Buskill were awarded grants of Phantom Common Units under our LTIP of 6,427 and 1,205 and Phantom GP Units under our SLTIP in the amount of 25 and 10. On July 24, 2006, Messrs. Gafvert and Buskill were awarded grants of Phantom GP Units under our SLTIP in the amount of 25 and 12. Each grant of Phantom Common Units under our LTIP vests 50% on the second anniversary of the grant date and 50% on the third anniversary of the grant date. Each grant of Phantom GP Units under our SLTIP vests within 48 months of the grant date, with the exception of the July 2006 grants, which vest within 42 months of the grant date.

- (2) The market value per unit reported in the above table is based on the NYSE closing market price on December 31, 2008, of \$17.78.
- (3) In addition to the Phantom Common Units, Messrs. Gafvert, Buskill, Cody and McMahon have accumulated non-vested amounts related to the DER that are tandem grants to the Phantom Common Units. Such DER amounts for Messrs. Gafvert, Buskill, Cody, and McMahon were \$23,798, \$2,170, \$11,897 and \$11,897 in 2008.
- (4) Due to Mr. Earley's resignation in May 2008, he did not have any unvested Phantom Common Units awarded under our LTIP or Phantom GP Units awarded under our SLTIP at December 31, 2008.

Option Exercises and Stock Vested

The following table presents information regarding the vesting during 2008 of Phantom Common Units and Phantom GP Units previously granted to the Named Executive Officers. We have not issued any awards in the form of options on our units to any employees, including Named Executive Officers.

| Option Exercise and Stock Vested for 2008 | | | | |
|--|--|---------------------------------------|---|---------------------------------------|
| Name | Stock Awards | | | |
| | (1) | | | |
| | Number of LTIP Shares Acquired on Vesting (#) | Value Received on Vesting (\$) | Number of SLTIP Shares Acquired on Vesting (#) | Value Received on Vesting (\$) |
| Rolf A. Gafvert | 7,229 | 170,361 | - | - |
| Jamie L. Buskill | 1,504 | 36,428 | - | - |
| Brian A. Cody | 2,276 | 52,650 | - | - |
| John C. Earley, Jr. (2) | 7,817 | 218,335 | 33 | 447,520 |
| Michael E. McMahon | 2,276 | 52,650 | - | - |

- (1) All vested awards were paid out as a lump sum cash payment and at no time were units issued to or owned by the Named Executive Officers.
- (2) Represents amounts paid to Mr. Earley upon his resignation related to accelerated vesting of Phantom Common Units and Phantom GP Units as consideration for his covenants, waivers and releases.

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. Gafvert, Cody and McMahon are, and during 2008 were, employees of our Gulf South subsidiary and are not covered under any Texas Gas benefit plans. Mr. Earley was also an employee of our Gulf South subsidiary until his resignation in May 2008. 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 2008 | | | | |
|----------------------------------|------------------|---|--|--|
| Name | Plan Name | Number of Years Credited Service (#) | Present Value of Accumulated Benefit (\$) | Payments During Last Fiscal Year (\$) |
| Jamie L. Buskill | TGRP | 22.3 | 186,109 | - |
| | SRP | 22.3 | 65,485 | - |

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 five 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. 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.

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 2008. 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, 2008, commencing in 2009, 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, 2008, 2007 and 2006 were 4.27%, 4.79% and 4.85% and for future years, 4.27%, 4.50% and 4.25%. The future normal retirement date accumulated cash balance is then discounted using an interest rate at December 31, 2008, 2007 and 2006 of 6.30%, 6.00% and 5.75%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2008 and 2007 of \$12,272 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 for participating employees for earnings that exceed the IRC compensation limitations for qualified defined benefit plans. 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 identical to the same provisions as described above for the TGRP. The increase in the present value of accumulated benefit for the SRP between years for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

Potential Payments Upon Termination or Change of Control

We do not govern the Named Executive Officer's employment relationships with formal employment agreements, though they are eligible to receive accelerated vesting of equity awards under certain of our compensation plans. We have made grants of Phantom Common Units and Phantom GP Units to each of our executives subject to specific vesting schedules and payment limitations, as discussed above. Each of these equity awards will vest immediately and become payable to the executive in cash upon the occurrence of certain events, as described below. A termination of employment may also trigger a distribution of retirement plan accounts from the TGRP or the SRP. These plan distributions will be no more than those amounts disclosed in the tables above, and such amounts will be paid only once in accordance with the terms of the applicable plan; thus, the table below does not include amounts attributable to the retirement plans disclosed above.

Long-Term Incentive Plan. The Phantom Common Units generally vest over a three-year period; the first 50% will vest upon the second anniversary of the grant date, while the remaining 50% will vest on the third anniversary of the grant date. All unvested Phantom Common Units (and all DERs associated with such Phantom Common Units) will become fully vested upon our "change of control." 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 Corporation 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 also become fully vested upon an executive's death, disability, retirement, or termination by us without cause. 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. The award agreements define "retirement" as a termination on or after age 65 other than for "cause" (as defined below) or a termination of employment other than for cause, with the consent of our board of directors, on or after the age of 60. "Cause" will first be defined as such term is used in any applicable employment agreement between the executive and us, and in the absence of such an employment agreement, as: (a) a federal or state felony conviction; (b) dishonesty in the fulfillment of an executive's employment or engagement; (c) the executive's willful and deliberate failure to perform his employment duties in any material respect; or (d) any other event that our board of directors, in good faith, determines to constitute cause.

Strategic Long-Term Incentive Plan. Phantom GP Units do not provide for distribution rights as do the Phantom Common Units. Our SLTIP requires a minimum distribution amount per unit to be met prior to any payment on a Phantom GP Unit, otherwise the Phantom GP Unit will be forfeited without payment. Phantom GP Unit payments may be made in amounts equal to the product of the "formula value" of the units and the number of units held on the vesting date. The "formula value" under the SLTIP means the lesser of (a) the product of (1) the quotient of (i) cash distributions made to our general partner during the four consecutive calendar quarters prior to the vesting date, divided by (ii) the current yield on the units, multiplied by (2) .0001; or (b) \$50,000. As our general partner met its minimum distribution amount for the 2008 year, the Phantom GP Units held by our Named Executive Officers would be eligible to receive accelerated vesting and payout upon certain events.

All unvested Phantom GP Units will become vested upon our general partner's change of control. The SLTIP defines a "Change of Control" as one or more of the following events: (a) any person or group, other than our general partner's affiliates, becomes the owner of 50% or more of our general partner's equity interests; (b) any person, other than Loews Inc. or its affiliates, becomes the general partner of our general partner; or (c) the sale or other disposition of all or substantially all of our general partner's, or the general partner of our general partner's, assets to any person that is not an affiliate of our general partner or its general partner. As with the LTIP, if the Phantom GP Units are subject to IRC section 409A, the Change of Control definition will be the meaning of such term as found in the treasury regulations with respect to IRC section 409A.

Unvested Phantom GP Units will also vest upon a participant's death, disability, retirement, or a termination by our general partner other than for cause. The SLTIP definition for each of these terms is substantially similar to the definitions for the LTIP terms described above.

Texas Gas Severance Plan. The Texas Gas Severance Plan was terminated on December 31, 2008. The potential payments that the Named Executive Officers were entitled to receive under that plan are no longer available as of December 31, 2008.

PTO/Vacation. The Named Executive Officers will receive the accrued vacation and paid time off that they accumulated during the 2008 year, up to a three week maximum for employees of Texas Gas and a one week maximum for Gulf South employees.

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, 2008. The closing price of our common units on the NYSE on December 31, 2008, \$17.78, was used to calculate these amounts.

Mr. Earley is not included in the following table due to his termination of employment in May 2008. The actual compensation Mr. Earley received for his employment service in the 2008 year is reported above in the Summary Compensation Table.

Potential Payments Upon Termination or Change of Control at December 31, 2008

| Name | Plan Name | Change of Control (1) | Termination Other Than for Cause | Termination for Cause, or Voluntary Resignation | Retirement (2) | Death or Disability |
|----------------------|------------------|--------------------------|--|--|-------------------|---------------------|
| Rolf A. Gafvert | LTIP (3) | \$ 352,017 | \$ 352,017 | \$ - | \$ 352,017 | \$ 352,017 |
| | SLTIP (4) | 1,178,583 | 1,178,583 | - | 1,178,583 | 1,178,583 |
| | PTO/Vacation (5) | 6,250 | 6,250 | \$ 6,250 | 6,250 | 6,250 |
| | Total | <u>1,536,850</u> | <u>1,536,850</u> | <u>6,250</u> | <u>1,536,850</u> | <u>1,536,850</u> |
| Jamie L. Buskill (6) | LTIP (3) | 79,282 | 79,282 | - | 79,282 | 79,282 |
| | SLTIP (4) | 542,148 | 542,148 | - | 542,148 | 542,148 |
| | PTO/Vacation (5) | 16,875 | 16,875 | 16,875 | 16,875 | 16,875 |
| | Total | <u>638,305</u> | <u>638,305</u> | <u>16,875</u> | <u>638,305</u> | <u>638,305</u> |
| Brian A. Cody | LTIP (3) | 164,930 | 164,930 | - | 164,930 | 164,930 |
| | SLTIP (4) | 577,506 | 577,506 | - | 577,506 | 577,506 |
| | PTO/Vacation (5) | 4,615 | 4,615 | 4,615 | 4,615 | 4,615 |
| | Total | <u>747,051</u> | <u>747,051</u> | <u>4,615</u> | <u>747,051</u> | <u>747,051</u> |
| Michael E. McMahon | LTIP (3) | 142,793 | 142,793 | - | 142,793 | 142,793 |
| | SLTIP (4) | 506,791 | 506,791 | - | 506,791 | 506,791 |
| | PTO/Vacation (5) | 4,438 | 4,438 | 4,438 | 4,438 | 4,438 |
| | Total | <u>654,022</u> | <u>654,022</u> | <u>4,438</u> | <u>654,022</u> | <u>654,022</u> |

- (1) The amounts listed under the “Change of Control” column will apply only in the event that the Change of Control definition for that particular plan has been triggered.
- (2) Retirement age is defined under the LTIP and SLTIP as age 65 or older, although a participant in the plan can become fully vested in outstanding awards at age 60 with Board approval. Retirement of a participant prior to age 60 would result in the forfeiture of outstanding awards. As of December 31, 2008, none of the named executive officers were eligible for retirement as defined in the LTIP and the SLTIP.
- (3) LTIP amounts were determined by multiplying the number of unvested Phantom Common Units each executive held on December 31, 2008, by the value of our common units on that date, or \$17.78. The resulting number was then added to the value of the DERs that were associated with the accelerated Phantom Common Units. As of December 31, 2008, Messrs. Gafvert, Buskill, Cody and McMahon held Phantom Common Units of 18,460, 4,337, 8,607 and 7,362, respectively. The amount of DERs accrued for these units were for Messrs. Gafvert, Buskill, Cody and McMahon, \$23,798, \$2,170, \$11,897 and \$11,897, respectively.
- (4) SLTIP amounts were determined by multiplying the number of unvested Phantom GP Units each executive held on December 31, 2008, by the value of each GP unit on that date (\$11,785.83) based upon full vesting of outstanding awards and valued using the plan formula value assuming cash distributions made by the Partnership to our general partner for the four consecutive quarters ending on December 31, 2008, of \$12.6 million and an implied yield on our common units of 10.69% at December 31, 2008. As of December 31, 2008, Messrs. Gafvert, Buskill, Cody and McMahon held 100, 46, 49, and 43 Phantom GP Units, respectively.
- (5) Includes earned but unused vacation at December 31, 2008.
- (6) 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 above.

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 \$43,750 (\$50,000 for the chair of the Audit Committee), payable in equal quarterly installments, \$1,000 for each Board meeting attended which is not a regularly scheduled meeting, and an annual grant of 500 of our common units. 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. The following table displays information related to compensation paid to our Eligible Directors for 2008:

| Director Compensation for 2008 | | | |
|---------------------------------------|---|--------------------------------------|-----------------------|
| Name | Fees Earned or Paid in Cash (\$) | Stock Awards (1) (\$) | Total (\$) |
| William R. Cordes | 56,750 | 12,290 | 69,040 |
| Thomas E. Hyland (2) | 65,000 | 12,290 | 77,290 |
| Mark L. Shapiro | 56,750 | 12,290 | 69,040 |

- (1) On March 26, 2008, Messrs. Cordes, Hyland and Shapiro were each granted 500 common units. The grant date fair value of each unit award, based on the closing market price of \$24.58, was \$12,290.
- (2) Chair of the Audit Committee.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information, at February 13, 2009, as to the beneficial ownership of our common and class B units by beneficial holders of 5% or more of either such class of 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) | Class B Units Beneficially Owned | Percentage of Class B Units Beneficially Owned (1) | Percentage of Total Limited Partner Units Beneficially Owned |
|---|---------------------------------------|--|---|--|--|
| Jamie L. Buskill | - | - | - | - | - |
| Brian A. Cody | - | - | - | - | - |
| William R. Cordes | 1,000 | * | - | - | - |
| Rolf A. Gafvert | - | - | - | - | - |
| Thomas E. Hyland | 6,900 (2) | * | - | - | - |
| Michael E. McMahon | - | - | - | - | - |
| Jonathan E. Nathanson | 15,000 | * | - | - | - |
| Arthur L. Rebell | 39,083 (3) | * | - | - | - |
| Mark L. Shapiro | 11,500 | * | - | - | - |
| Andrew H. Tisch | 81,050 (4) | * | - | - | - |
| All directors and executive officers as a group | 154,533 | * | - | - | - |
| BPHC (5) | 107,534,609 | 69% | 22,866,667 | 100% | 73% |
| Loews Corporation (5) | 107,534,609 | 69% | 22,866,667 | 100% | 73% |

*Represents less than 1% of the outstanding common units

- (1) As of February 13, 2009, we had 154,934,609 common units and 22,866,667 class B units issued and outstanding.
- (2) 400 of these units are owned by Mr. Hyland's spouse.
- (3) 32,984 of these units are owned by ARebell, LLC, a limited liability company controlled by Mr. Rebell.
- (4) 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.
- (5) Loews Corporation 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 the 2% general partner interest and all of our incentive distribution rights. Including the general partner interest but excluding the impact of the incentive distribution rights, Loews indirectly owns approximately 74% of our total ownership interests. *Our Partnership Interests* in Item 5 contains more information regarding our calculation of BPHC's equity ownership.

Securities Authorized for Issuance Under Equity Compensation Plans

In 2005, our Board adopted the Boardwalk Pipeline Partners, LP Long-Term Incentive Plan. The following table provides certain information as of December 31, 2008, 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 | 3,521,000 |

Note 10 in 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 2008 nor were there any service transactions where the policy was not followed.

In 2008, we issued 22.9 million class B units and 21.2 million common units to BPHC resulting in net proceeds of \$1.2 billion. In conjunction with these transactions, we also entered into a registration rights agreement with BPHC. These transactions were subject to review and approval by our Board, including separate approval by our Conflicts Committee. Distributions are approved by the Board on a quarterly basis prior to declaration. Note 7 and Note 17 in Item 8 of this Report contain 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 2008 and 2007 by category as described in the notes to the table (in millions):

| | <u>2008</u> | <u>2007</u> |
|------------------------|---------------|---------------|
| Audit fees (1) | \$ 1.9 | \$ 2.2 |
| Audit related fees (2) | <u>0.5</u> | <u>0.5</u> |
| Total | <u>\$ 2.4</u> | <u>\$ 2.7</u> |

- (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, including, principally, consents and 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:

Reports of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2008 and 2007

Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Changes in Partners' Capital for the years ended December 31, 2008, 2007 and 2006

Consolidated Statements of Comprehensive Income for the years ended December 31, 2008, 2007 and 2006

Notes to Consolidated Financial Statements

(a) 2. Financial Statement Schedules

Valuation and Qualifying Accounts

The following table presents those accounts that have a reserve as of December 31, 2008, 2007 and 2006 and are not included in specific schedules herein. These amounts have been deducted from the respective assets on the Consolidated Balance Sheets (in millions):

| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Other Additions (Recoveries) | Deductions (Write-offs) | Balance at End of Period |
|-------------------------------------|--------------------------------------|-------------------------------------|------------------------------------|----------------------------|--------------------------------|
| Allowance for doubtful accounts: | | | | | |
| 2008 | \$ 0.4 | \$ - | \$ (0.1) | \$ - | \$ 0.3 |
| 2007 | 2.6 | 2.7 | (4.7) | (0.2) | 0.4 |
| 2006 | 0.7 | 2.1 | - | (0.2) | 2.6 |
| Inventory obsolescence: | | | | | |
| 2008 | \$ 0.1 | \$ - | \$ - | \$ (0.1) | \$ - |
| 2007 | - | - | 0.1 | - | 0.1 |
| 2006 | - | - | - | - | - |

(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). |
| 4.1 | Amended and Restated Registration Rights Agreement dated November 4, 2008, 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 November 4, 2008). |
| 4.2 | 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). |
| 4.3 | 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). |
| 4.4 | 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). |

- 4.5 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).
- 4.6 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).
- 4.7 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).
- 4.8 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).
- 4.9 Indenture dated August 17, 2007, between Gulf South Pipeline Company, LP and the Bank of New York Trust Company, N.A. (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report on Form 8-K filed on August 17, 2007).
- 4.10 Indenture dated March 27, 2008, 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 March 27, 2008).
- 10.1 Amended and Restated Revolving Credit Agreement, dated as of June 29, 2006, among Boardwalk Pipelines, LP, Boardwalk Pipeline Partners, LP, the several banks and other financial institutions or entities parties to the agreement as lenders, the issuers party to the agreement, Wachovia Bank, National Association, as administrative agent for the lenders and the issuers, Citibank, N.A., as syndication agent, JPMorgan Chase Bank, N.A., Deutsche Bank Securities, Inc. and Union Bank of California, N.A., as co-documentation agents, and Wachovia Capital Markets LLC and Citigroup Global Markets Inc., as joint lead arrangers and joint book managers (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on July 5, 2006).
- 10.2 Amendment No. 1 to Amended and Restated Revolving Credit Agreement, dated as of April 2, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, each a wholly-owned subsidiary of the Registrant, as Borrowers, and the agent and lender parties identified therein (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on April 5, 2007).
- 10.3 Amendment No. 2 to Amended and Restated Revolving Credit Agreement, dated as of November 27, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 29, 2007).
- 10.4 Amendment No. 3 to Amended and Restated Revolving Credit Agreement, dated as of March 6, 2008, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein. (Incorporated by reference to Exhibit 10.1 to the Registrant's Quarterly Report on Form 10-Q filed on April 29, 2008).
- **10.5 Separation Agreement and General Release between John C. Earley, Jr. and Gulf South Pipeline Company, LP, Gulf Crossing Pipeline Company LLC, Texas Gas Transmission, LLC, Boardwalk GP, LLC and Boardwalk Operating GP, LLC. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed on July 29, 2008).

- 10.6 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)
- **10.7 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).
- **10.8 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).
- **10.9 Boardwalk Pipeline Partners, LP Strategic Long-Term Incentive Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on July 28, 2006).
- **10.10 Form of GP Phantom Unit Award Agreement under the Boardwalk Pipeline Partners, LP Strategic Long-Term Incentive Plan (Incorporated by reference to Exhibits 10.1 and 10.2 to the Registrant's Current Report on Form 8-K filed on July 28, 2006).
- **10.11 Separation Agreement and General Release between H. Dean Jones II and Texas Gas Transmission, LLC, Boardwalk GL, LLC, Boardwalk Pipelines Holding Corp. and Boardwalk Operating GP, LLC. (Incorporated by reference to Exhibit 10.2 to the Registrant's Quarterly Report on Form 10-Q filed on April 29, 2008).
- 10.12 Loan Agreement, dated December 1, 2008, Mississippi Business Finance Corporation and Gulf South Pipeline Company, LP (Incorporated by reference to Exhibit 4.2 to the Registrant's Current Report of Form 8-K filed on December 9, 2008).
- 10.13 Bond Purchase Agreement, dated December 1, 2008, among Boardwalk Pipelines, LP, Mississippi Business Finance Corporation and Gulf South Pipeline Company, LP (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report of Form 8-K filed on December 9, 2008).
- *18.1 Preferability letter, dated February 24, 2009, from Independent Registered Public Accounting Firm.
- *21.1 List of Subsidiaries of the Registrant.
- *23.0 Consent Of Independent Registered Public Accounting Firm.
- *31.1 Certification of Rolf A. Gafvert, 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 Rolf A. Gafvert, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
- *32.2 Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed 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 10.9 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 24, 2009 By: /s/ Jamie L. Buskill
Jamie L. Buskill
Senior Vice President, Chief Financial 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 24, 2009 /s/ Rolf A. Gafvert
Rolf A. Gafvert
President, Chief Executive Officer and Director
(principal executive officer)

Dated: February 24, 2009 /s/ Jamie L. Buskill
Jamie L. Buskill
Senior Vice President, Chief Financial Officer and Treasurer
(principal financial officer)

Dated: February 24, 2009 /s/ Steven A. Barkauskas
Steven A. Barkauskas
Vice President, Controller and Chief Accounting Officer
(principal accounting officer)

Dated: February 24, 2009 /s/ William R. Cordes
William R. Cordes
Director

Dated: February 24, 2009 /s/ Thomas E. Hyland
Thomas E. Hyland
Director

Dated: February 24, 2009 /s/ Jonathan E. Nathanson
Jonathan E. Nathanson
Director

Dated: February 24, 2009 /s/ Arthur L. Rebell
Arthur L. Rebell
Director

Dated: February 24, 2009 /s/ Mark L. Shapiro
Mark L. Shapiro
Director

Dated: February 24, 2009 /s/ Andrew H. Tisch
Andrew H. Tisch
Director

February 24, 2009

Boardwalk Pipeline Partners, LP
9 Greenway Plaza, Suite 2800
Houston, Texas

Dear Sirs:

We have audited the consolidated financial statements of Boardwalk Pipeline Partners, LP as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, included in your Annual Report on Form 10-K to the Securities and Exchange Commission and have issued our report thereon dated February 24, 2009, which expresses an unqualified opinion. Note 2 to such consolidated financial statements contains a description of your change during the year ended December 31, 2008 in accounting for customer owned gas in storage. In our judgment, such change is to an alternative accounting principle that is preferable under the circumstances.

Yours truly,

DELOITTE & TOUCHE LLP
Houston, Texas

BOARDWALK PIPELINE PARTNERS, LP
Subsidiaries of the Registrant
December 31, 2008

| <u>Name of Subsidiary</u> | <u>Organized Under Laws of</u> | <u>Business Names</u> |
|------------------------------------|---------------------------------------|------------------------------|
| Boardwalk Operating GP, LLC | Delaware | |
| Boardwalk Pipelines, LP | Delaware | |
| Texas Gas Transmission, LLC | Delaware | Texas Gas |
| Gulf South Pipeline Company, LP | Delaware | Gulf South |
| GS Pipeline Company, LLC | Delaware | |
| Gulf Crossing Pipeline Company LLC | Delaware | Gulf Crossing |

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-141058 on Form S-3 of our reports dated February 24, 2009, relating to the consolidated financial statements and consolidated financial statement schedule of Boardwalk Pipeline Partners, LP and the effectiveness of Boardwalk Pipeline Partners, LP's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Boardwalk Pipeline Partners, LP for the year ended December 31, 2008.

DELOITTE & TOUCHE LLP
Houston, Texas
February 24, 2009

I, Rolf A. Gafvert, certify that:

- 1) I have reviewed this report on Form 10-K of Boardwalk Pipeline Partners, LP;
- 2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
- 3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
- 4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
- 5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 24, 2009

/s/ Rolf A. Gafvert

Rolf A. Gafvert

President, Chief Executive Officer and Director

I, Jamie L. Buskill, certify that:

- 1) I have reviewed this report on Form 10-K of Boardwalk Pipeline Partners, LP;
- 2) Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
- 3) Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
- 4) The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
- 5) The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
 - a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Dated: February 24, 2009

/s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer

**Certification by the Chief Executive Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)**

Pursuant to 18 U.S.C. Section 1350, the undersigned chief executive officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2008, (the Report) of Boardwalk Pipeline Partners, LP (the Partnership) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

February 24, 2009

/s/ Rolf A. Gafvert

Rolf A. Gafvert

President, Chief Executive Officer and Director
(principal executive officer)

**Certification by the Chief Financial Officer
of
Boardwalk GP, LLC
pursuant to 18 U.S.C. Section 1350
(as adopted by Section 906 of the Sarbanes-Oxley Act of 2002)**

Pursuant to 18 U.S.C. Section 1350, the undersigned chief financial officer of Boardwalk GP, LLC hereby certifies, to such officer's knowledge, that the annual report on Form 10-K for the year ended December 31, 2008, (the Report) of Boardwalk Pipeline Partners, LP (the Partnership) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 and the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

February 24, 2009

/s/ Jamie L. Buskill

Jamie L. Buskill

Senior Vice President, Chief Financial Officer and Treasurer
(principal financial officer)