Boardwalk Pipeline Partners, LP
Form 10-K
February 26, 2008

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

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2007

OR

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

Commission file number: 01-32665

BOARDWALK PIPELINE PARTNERS, LP
(Exact name of registrant as specified in its charter)

DELAWARE
(State or other jurisdiction of incorporation or organization)

20-3265614
(I.R.S. Employer Identification No.)

9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122
(Address and Telephone Number of Registrant's Principal Executive Office)
Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Units Representing Limited Partner Interests	New York Stock Exchange

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x Noo

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

The aggregate market value of the common units of the registrant held by non-affiliates as of June 30, 2007 was approximately $1.1 billion. As of February 15, 2008, the registrant had 90,656,122 common units outstanding.

Documents incorporated by reference. None.

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BOARDWALK PIPELINE PARTNERS, LP

PART I

Item 1. Business

Introduction

We are a Delaware limited partnership formed in 2005 to own and operate the business conducted by Boardwalk Pipelines, LP (Boardwalk Pipelines) and its subsidiaries, Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (together, operating subsidiaries). Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews), owns 53.3 million of our common units and 33.1 million of our subordinated units, constituting approximately 68.0% of our equity. Boardwalk GP, LP (Boardwalk GP), an indirect, wholly-owned subsidiary of BPHC, is our general partner and holds a 2.0% general partner interest and all of our incentive distribution rights. Our common units are traded under the symbol “BWP” on the New York Stock Exchange (NYSE).

Our Business

We are engaged in the interstate transportation and storage of natural gas. We own and operate two natural gas pipeline systems which we use to transport and store natural gas for a broad mix of customers, including local distribution companies (LDCs), municipalities, interstate and intrastate pipelines, direct industrial users, electric power generation plants, marketers and producers. Our transportation and storage rates and general terms and conditions of service (tariff) 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 our costs and earn a reasonable return on equity, however there can be no assurance that we will recover those costs or earn a reasonable return. Our firm and interruptible storage rates for Gulf South are market-based pursuant to authority granted by the 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) as well as other charges based on actual utilization of the capacity. For the year ended December 31, 2007, approximately 65.0% of our revenues were derived from capacity reservation charges under firm contracts, approximately 17.0% of our revenues were derived from other charges based on actual utilization under firm contracts and approximately 18.0% of our revenues were derived from interruptible transportation, interruptible storage, parking and lending (PAL) and other services.

We are currently undertaking several significant pipeline and storage expansion projects.

Our Pipeline and Storage Systems

Our operating subsidiaries own and operate approximately 13,550 miles of pipeline, directly serving customers in eleven states and indirectly serving customers throughout the northeastern and southeastern United States through numerous interconnections with unaffiliated pipelines. In 2007, our pipeline systems transported approximately 1.3 trillion cubic feet (Tcf) of gas. Average daily throughput on our pipeline systems during 2007 was approximately 3.6 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 155.0 Bcf. We conduct all of our natural gas transportation and 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, Perryville, Louisiana area, Henry Hub in Louisiana, Agua Dulce and Carthage, Texas. Carthage, Texas provides access to natural gas supplies from the Bossier Sands and Barnett Shale gas producing regions in East Texas. The Henry Hub serves as the designated delivery point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). We also access wellhead supplies in eastern Texas, northern and southern Louisiana and Mississippi. We also have access to imported liquefied natural gas (LNG) through the Lake Charles, Louisiana LNG terminal, to mid-continent gas production through several third-party pipeline interconnects, and to Canadian natural gas through a pipeline interconnect with Midwestern Gas Transmission Company at Whitesville, Kentucky.

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 4.5 Bcf per day;
- 30 compressor stations having an aggregate of approximately 253,600 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 numbers shown above include 242 miles of large diameter pipeline and one compressor station from our East Texas to Mississippi expansion project. See Expansion Projects for more information regarding the East Texas to Mississippi expansion project.

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 United States.

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:

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approximately 5,850 miles of pipeline, having a peak-day delivery capacity of approximately 3.8 Bcf per day which includes deliveries to pipeline interconnects in South Louisiana;

- 31 compressor stations having an aggregate of approximately 552,000 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 72.0 Bcf is designated as working gas.

The numbers shown above include 9.0 Bcf of working gas capacity from Phase II of our Western Kentucky storage expansion project. See Expansion Projects for more information regarding the Western Kentucky storage expansion project.

The direct market area for Texas Gas encompasses eight states in the southern and midwestern United States 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 balancing needs on its system, to meet the operational requirements of its firm and interruptible 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 substantially 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:

East Texas to Mississippi Expansion. On June 18, 2007, the FERC granted us the authority to construct, own and operate a pipeline expansion consisting of approximately 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression, having approximately 1.7 Bcf of new peak-day transmission capacity. Customers have contracted at fixed rates for 1.4 Bcf per day of firm transportation capacity on a long-term basis (with a weighted average term of approximately 6.8 years) from Carthage, Texas, which represents substantially all of the normal operating capacity. The pipeline facilities from Keatchie, Louisiana in DeSoto Parish to interconnects with Texas Gas near Bosco, Louisiana, and Columbia Gulf Transmission pipeline at Delhi, Louisiana began flowing gas on December 31, 2007. The remaining pipeline facilities from Delhi, Louisiana to Harrisville, Mississippi, began flowing gas during January 2008. Currently, the three compressor units at our Carthage compressor station are operational and we are making all of our primary firm contractual deliveries into the Delhi, Louisiana area and a substantial percentage of our primary firm contractual deliveries to markets in Mississippi. We are in the process of commissioning the remaining compression facilities associated with this project, which we expect to be completed during the second quarter 2008.

Gulf Crossing Project. We are pursuing construction of a new interstate pipeline that will begin near Sherman, Texas and proceed to the Perryville, Louisiana area. The project will be owned by Gulf Crossing Pipeline Company, LLC (Gulf Crossing), our newly formed interstate pipeline subsidiary, and will consist of approximately 357 miles of 42-inch pipeline having up to approximately 1.7 Bcf of peak-day transmission capacity. Additionally, Gulf Crossing has entered into, subject to regulatory approval: (i) an operating lease for up to 1.4 Bcf per day of capacity on our Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85); and (ii) an operating lease with Enogex, a third-party intrastate pipeline, which will bring certain gas supplies to our system. Customers have contracted at fixed rates for 1.1 Bcf per day of long-term firm transportation capacity (with a weighted average term of approximately 9.5 years). The certificate application for this project was filed with the FERC on June 19, 2007, and we expect this project to be in service by the first quarter 2009.

Southeast Expansion. On September 28, 2007, the FERC granted us the authority to construct, own and operate a pipeline expansion originating near Harrisville, Mississippi and extending to an interconnect with Transco 85. This expansion will initially consist of approximately 112 miles of 42-inch pipeline having approximately 1.2 Bcf of peak-day transmission capacity. To accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above, this project will be expanded to 2.2 Bcf of peak-day transmission capacity. In addition, the FERC approved our 260 MMcf per day operating lease with Destin Pipeline Company which will provide us enhanced access to markets in Florida. Customers have contracted at fixed rates for 660 MMcf per day of firm transportation capacity on a long-term basis (with a weighted-average term of 8.7 years), in addition to the capacity leased to Gulf Crossing discussed above. Construction has commenced and we expect this project to be in service during the second quarter 2008.

Fayetteville and Greenville Laterals. We are pursuing the construction of two laterals connected to 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 and consist of approximately 165 miles of 36-inch pipeline with an initial design of approximately 0.8 Bcf of peak-day transmission capacity. 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 pipeline with an initial design capacity of approximately 0.8 Bcf of peak-day transmission capacity. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. Customers have contracted at fixed rates for 575 MMcf per day of initial capacity, with options for additional capacity that, if exercised, could add 325 MMcf per day of capacity. The certificate application for this project was filed with the FERC on July 11, 2007. We expect the first 60 miles of the Fayetteville Lateral to be in service during the third quarter 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

Pipeline Expansion Project Costs and Timing. We currently estimate that the total cost of the pipeline expansion projects discussed above will be approximately $4.5 billion, of which approximately $2.0 billion was spent or committed to material that was on order as of December 31, 2007. Our total estimated cost assumes that we will receive the necessary regulatory approvals to commence construction by June 1, 2008 on Gulf Crossing and the Fayetteville and Greenville Laterals and that we will receive the regulatory approvals to operate the pipelines on certain of our projects at higher pressures, which will allow us to utilize a higher percentage of the pipeline capacity. Delays in receipt of any of these approvals will result in higher costs and additional delays in our expected in-service dates, which would also result in delays of revenues we would have received had these delays not occurred, and in certain instances will result in the payment of penalties to certain customers.

The increase in our estimated total costs and delays reflects, among other things, higher costs due to scope changes, adverse weather conditions, delays in the receipt of regulatory approvals, and the effects of the strong demand for and limited supply of qualified contractors, labor and materials and equipment which has occurred as a result of the number of large, complex pipeline construction projects being constructed in 2007 and 2008. These difficult market conditions have resulted in higher contractor costs, higher costs for labor, materials, construction equipment and other equipment and parts, as well as shortages of skilled labor. These conditions are expected to persist and it is possible that they could result in further cost increases and delays, which could have a material adverse impact on our financial condition, results of operations and cash flows.

Storage Expansion Projects:

Western Kentucky Storage Expansion Phase II. In December 2006, the FERC issued a certificate approving the Phase II storage expansion project which expanded the working gas capacity in our western Kentucky storage complex by approximately 9.0 Bcf. This project is supported by binding commitments from customers to contract on a long-term basis (with a weighted-average term of 8.3 years) for the full additional capacity at the Texas Gas maximum applicable rate. The project was placed in service in November 2007.

Western Kentucky Storage Expansion Phase III. We have signed 10-year precedent agreements for 5.1 Bcf of storage capacity for our Phase III storage project. The certificate application for this project was filed with the FERC on June 25, 2007, seeking approval to develop up to 8.3 Bcf of new storage capacity if Texas Gas is granted market-based rate authority for the new storage capacity being proposed. The cost of this project will be dependent on the ultimate size of the expansion. We expect 5.4 Bcf of storage capacity to be in service in 2008.

Magnolia Storage Facility. 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 will be unable to place the cavern in service as expected. As a result, we have elected to abandon that cavern and are exploring the possibility of securing a new site on which a new cavern could be developed.

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 firm 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 (including NNS) are generally consistent during the contract term, but can be higher in winter peak periods, especially related to NNS agreements, than off-peak periods. Firm transportation contracts generally range in term from one to ten years, although short-term firm transportation services can be offered for any term ranging from one day to 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, and applicable injection and withdrawal fees. Generally, interruptible storage agreements are for monthly terms. Unlike most FERC-regulated pipelines, including Texas Gas, Gulf South is authorized to charge market-based rates for its firm and interruptible storage services. Texas Gas filed for the ability to charge market-based rates on capacity 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 and require a reservation of a specified amount of storage and transportation capacity. Customers pay a reservation charge based upon the capacity reserved plus a commodity and fuel charge based on the volume of gas actually transported. NNS and SNS provide customers with additional flexibility over traditional firm transportation and storage services. 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 LDCs, municipalities, intrastate and interstate pipelines, direct industrial users, electric power generators, marketers and producers located throughout the Gulf Coast, Midwest and Northeast regions of the United States. Customers on our Gulf South system are located throughout its service area and elsewhere or are accessed through numerous interconnects on unaffiliated pipeline systems. In contrast, 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.

Based upon 2007 revenues, our customer mix was comprised as follows: LDCs (32.0%), pipeline interconnects (34.0%), storage (13.0%), industrial end-users (7.0%), power plants (6.0%) and other (8.0%). We contract directly with end-use customers and with marketers, producers and other third parties who provide transportation and storage services to end users. One customer, Atmos Energy accounted for approximately 10.0% of our 2007 operating revenues.

LDCs. Most of our LDC customers use firm transportation services, including NNS. These customers operate under contracts having a weighted-average contract term of approximately four years as of December 31, 2007. We serve approximately 190 LDCs located across our pipeline systems. The demand of these customers peaks during the winter heating season.

Pipeline Interconnects (off system). Our pipeline systems serve as feeder pipelines for long-haul interstate pipelines serving markets throughout the northeastern and southeastern United States. We have numerous interconnects with third-party interstate and intrastate pipelines.

Storage. We provide storage services to a broad mix of customers including LDCs, marketers and producers. Typically, LDCs use storage under their NNS contracts to manage winter gas supplies, marketers and producers use storage to facilitate trading opportunities, and producers also use storage to ensure their ability to produce on a consistent basis.

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.

Power Plants. We 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.

Competition

We compete with numerous intrastate and interstate 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 several new pipeline projects that are under way, including the Rockies Express Pipeline that will transport natural gas from northern Colorado to eastern Ohio; the Heartland Gas Pipeline currently in operation in Indiana; the Southeast Header Supply System that is currently being constructed and will transport gas from Perryville, Louisiana to markets in Florida; and the proposed Mid-Continent

Express Pipeline that would transport gas from Texas to Alabama. The principal elements of competition among pipelines are rates, terms of service, access to supply and flexibility and reliability of service. 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. Our business is, in part, dependent on the volumes of natural gas consumed in the United States. Our competitors attempt to attract new supply to their pipelines including those that are currently connected to markets served by us. We compete with these entities to maintain current business levels and to serve new demand and markets. Additionally, natural gas competes with other forms of energy available to our customers, including electricity, coal, and fuel oils.

Seasonality

Our revenues are seasonal in nature and are affected by weather and natural gas price volatility. Weather impacts natural gas demand for power generation and heating purposes, which in turn influences the 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. Natural gas prices are also volatile, influencing drilling and production which can affect the value of our storage and PAL services. Peak demand for natural gas occurs during the winter months, caused by the heating load. During 2007, approximately 56.0% of our total operating revenues were recognized in the first and fourth calendar quarters.

Government Regulation

The FERC regulates pipelines under the Natural Gas Act of 1938 (NGA) and the Natural Gas Policy Act of 1978. The FERC regulates, among other things, the rates and charges for the transportation and storage of natural gas in interstate commerce, the extension, enlargement or abandonment of jurisdictional facilities, and the financial accounting of certain regulated pipeline companies. We are also regulated by the United States 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.

Where required, our operating subsidiaries hold certificates of public convenience and necessity issued by the FERC covering certain of their facilities, activities, and services. The FERC also prescribes accounting treatment for regulatory purposes. The books and records of the operating subsidiaries may be periodically audited by the FERC.

The maximum rates that may be charged by us for gas transportation and in the case of Texas Gas, for storage services, are established through the FERC 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 on capital investments, 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 of our operating subsidiaries has an obligation to file a new rate case.

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

(a) the Clean Air Act and analogous state laws which impose obligations related to air emissions;

(b) 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;

(c) 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

(d) 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, 2007, we had 1,084 employees, approximately 85 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 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 which covers Texas Gas employees hired prior to November 1, 2006. Note 9 in Item 8 of this Report contains further discussion of our employee benefits.

Available Information

Our internet website is located at www.bwpmlp.com. We make available free of charge, through our website, our annual reports on Form 10-K, 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 reasonably practicable after 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 before investing in any securities issued by us should be carefully considered and evaluated.

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 expansion projects, as discussed above under Business – Expansion Projects, and we may also consider additional expansion projects in the future. In pursuing these projects, we have experienced significant cost overruns, including penalties to contractors, and we may experience additional cost increases in the future. We have also experienced construction delays and may experience additional delays in the future. Delays in construction have resulted in reduced transportation rates and liquidated damage payments to customers, as well as lost revenue opportunities and could, in the future result in similar losses or, in some cases, provide customers the right to terminate their transportation agreements relating to the delayed project.

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

- delays in obtaining regulatory approvals;
- adverse weather conditions;
- 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 terms, at the cost, or under the schedule that we anticipate, or at all. In addition, we cannot be certain that, if completed, these projects will perform in accordance with our expectations and 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. Any of these factors could materially adversely affect our ability to realize the anticipated benefits from expansion projects which could have a material adverse effect on our business, financial condition, results of operations and cash flows. See also Item 1 – Expansion Projects.

Completion of our expansion projects will require significant amounts of debt and equity financing which may not be available to us on acceptable terms, or at all.

We plan to fund our expansion capital expenditures with proceeds from sales of our debt and equity securities and borrowings under our revolving credit facility; however, we cannot be certain that we will be able to issue our debt and equity securities on terms or in the proportions that we expect, or at all, particularly in light of the cost increases and construction delays we have experienced to date on our expansion projects, current credit market disruptions surrounding sub-prime residential mortgage concerns and the impact that those factors and other events are having and may have on the public securities markets generally and on the market for our securities in particular. Future sales of our equity securities would be dilutive to existing securityholders. A significant increase in our indebtedness, or an increase in our indebtedness that is proportionately greater than our issuances of equity, as well as the project cost increases and credit market conditions discussed above could negatively impact our credit ratings or our ability to remain in compliance with the financial covenants under our revolving credit agreement which could have a material adverse effect on our financial condition, results of operations and cash flows. If we are unable to finance our expansion projects as expected, we could be required to seek alternative financing, the terms of which may not be attractive to us, or to revise or cancel our expansion plans.

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

The operating and financial covenants in our revolving credit agreement 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 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.

Our natural gas transportation, gathering and storage operations are subject to Federal Energy Regulatory Commission's rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating our pipelines including a reasonable return.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our ability to establish reasonable rates, or 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 cover current costs, including a reasonable return. We cannot make assurances that we will 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, financial condition and results of operations.

In 2005, FERC established a policy regarding the ability of a regulated entity to collect an allowance for income taxes in its cost of service. Generally, FERC has stated it will permit a pipeline that is a partnership (or other pass-through entity) to include in its cost-of-service an income tax allowance to the extent that its partners have an actual or potential income tax liability on the jurisdictional income generated by the partnership (or other pass-through entity). FERC will review pipelines' ability to include such an income tax allowance in their costs of service on a case-by-case basis, and the burden is on the pipelines to show that it had such actual or potential income tax liability. That policy has been further refined in 2006 and 2007 through a series of FERC orders and decisions issued by the United States Court of Appeals for the District of Columbia Circuit. Most recently, FERC's income tax allowance policy was upheld on all issues subject to appeal by the United States Court of Appeals for the District of Columbia Circuit in a decision issued in May 2007. In December 2007, FERC issued an order that again affirmed its income tax allowance policy and further clarified the implementation of that policy. If the FERC were to change its income tax allowance policy in the future, such changes could materially and adversely impact the rates we are permitted to charge as future rates are approved for our interstate transportation services.

In a related interstate oil pipeline proceeding, FERC noted that the tax deferral features of a publicly traded partnership may cause some investors to receive, for some indeterminate duration, cash distributions in excess of their taxable income, which FERC characterized as a "tax savings." FERC stated a concern that this creates an opportunity for those investors to earn an additional equity return funded by ratepayers. Responding to this concern, FERC adjusted the pipeline's equity rate of return downward based on the percentage by which the publicly traded partnership's cash flow exceeded taxable income assumed in the methodology for calculating the rate of return. A rehearing request is pending before FERC on this issue. If FERC establishes a policy of lowering a regulated entities' equity rate of return to compensate for what it considers to be a "tax savings," it is also likely that the level of maximum lawful rates would decrease from current levels.

If our subsidiaries were to file a rate case or if we were to be required to defend our rates, we would be required to establish pursuant to the income tax policy that the inclusion of an income tax allowance in our cost of service was just and reasonable. To establish that our income tax allowance is just and reasonable, our general partner may elect to require owners of our units to recertify their status as being subject to United States 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 that we will be able to provide (including the information the general partner may require in the certification and recertification process) will be sufficient to establish that its unitholders, or its unitholders' owners, are subject to United States federal income tax liability on the income generated by our jurisdictional pipelines. If we are unable to establish that our unitholders, or our unitholders' owners, incur actual or potential income tax liability on the income generated by our jurisdictional pipelines, FERC could disallow a substantial portion of our regulated pipelines' income tax allowance. If FERC were to disallow a substantial portion of our regulated pipelines' income tax allowance, it is likely that the level of maximum lawful rates would decrease from current levels.

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

The FERC's regulatory authority also 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.

The FERC's action in any of these areas or modifications of its current regulations can adversely impact our ability to compete for business, the costs we incur in our operations, the construction of new facilities or our ability to recover the full cost of operating our pipelines. Another example is the time the FERC takes to approve the construction of new facilities, which could give our non-regulated competitors time to offer alternative projects or raise the costs of our projects to the point where they are no longer economical.

The FERC has authority to review pipeline contracts. If the FERC determines that a term of any such contract deviates in a material manner from a pipeline's tariff, the FERC typically will order the pipeline to remove the term from the contract and execute and re-file a new contract with the FERC, or alternatively, amend its tariff to include the deviating term, thereby offering it to all shippers. If the FERC audits a pipeline's contracts and finds material deviations that appear to be unduly discriminatory, the FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

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Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines. Under the recently enacted Energy Policy Act of 2005, the FERC has civil penalty authority under NGA to impose penalties for current violations of up to $1,000,000 per day for each violation.

Finally, we cannot give any assurance regarding the future regulations under which we will operate our natural gas transportation and storage businesses, or the effect such regulation could have on our financial condition, results of operations and cash flows.

The outcome of certain FERC proceedings involving FERC policy statements is uncertain and could affect the level of return on equity that the Partnership may be able to achieve in any future rate proceeding.

In an effort to provide some guidance and to obtain further public comment on FERC's policies concerning return on equity determinations, on July 19, 2007, FERC issued its Proposed Proxy Policy Statement, Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity. In the Proposed Proxy Policy Statement, FERC proposes to permit inclusion of publicly traded partnerships in the proxy group analysis relating to return on equity determinations in rate proceedings, provided that the analysis be limited to actual publicly traded partnership distributions capped at the level of the pipeline's earnings and that evidence be provided in the form of multiyear analysis of past earnings demonstrating a publicly traded partnership's ability to provide stable earnings over time.

In a decision issued shortly after FERC issued its Proposed Proxy Policy Statement, the D.C. Circuit vacated FERC's orders in a proceeding involving High Island Offshore System and Petal Gas Storage. The Court determined that FERC had failed to adequately reflect risks of interstate pipeline operations both in populating the proxy group (from which a range of equity returns was determined) with entities the record indicated had lower risk, while excluding publicly traded partnerships primarily engaged in interstate pipeline operations, and in the placement of the pipeline under review in each proceeding within that range of equity returns. Although the Court accepted for the sake of argument FERC's rationale for excluding publicly traded partnerships from the proxy group (i.e., publicly traded partnership distributions may exceed earnings) it observed this proposition was "not self-evident."

The ultimate outcome of these proceedings is not certain and may result in new policies being established at FERC that would not allow the full use of publicly traded partnership distributions to unitholders in any proxy group comparisons or other negative adjustments used to determine return on equity in future rate proceedings. In addition, the FERC may adopt other policies or institute other proceedings that could adversely affect our ability to achieve a reasonable level of return on equity in any future rate proceeding.

Catastrophic losses are unpredictable.

The nature and location of our business, particularly with regard to our assets in the Gulf Coast region, may make us susceptible to catastrophic losses especially from hurricanes or named storms. Various other events can cause catastrophic losses, including windstorms, earthquakes, hail, explosions, and severe winter weather and fires. The frequency and severity of these events are inherently unpredictable. The extent of losses from catastrophes is a function of both the total amount of insured exposures in the affected areas and the severity of the events themselves. Although we carry insurance, in the event of a loss the coverage could be insufficient or there could be a material delay in the receipt of the insurance proceeds.

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

The risk of substantial environmental costs and liabilities is inherent in natural gas transportation and storage. 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.

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. 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. For example, the federal government and several states have recently proposed increased environmental regulation of many industrial activities, including increased regulation of air quality, water quality and solid waste management. In addition, government action to reduce greenhouse gas emissions and other government actions that may have the effect of requiring or encouraging reduced consumption or production of natural gas, could adversely impact our business, financial condition, results of operations and cash flows.

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. The steps we may be required to take to bring certain of our facilities into compliance could be prohibitively expensive and we may be required to shut down or alter the operation of those facilities, which might cause us to incur losses. Further, 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. The costs of complying with environmental regulation in the future could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our operations are subject to 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, all of which could cause substantial financial losses. 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 revenue 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 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. Moreover, after Hurricanes Katrina and Rita, there can be no assurance that we will be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, or that the insurance coverage we do obtain will not contain large deductibles or fail to cover certain hazards or all potential losses. The occurrence of any operating risks not fully covered by insurance could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Pipeline safety integrity programs and repairs may impose significant costs and liabilities on us.

The United States DOT Pipeline and Hazardous Materials Safety Administration (PHMSA) has issued a final rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate certain areas along their pipelines and take additional measures to protect pipeline segments located in what the rule refers to as high consequence areas (HCAs) where a leak or rupture could potentially do the most harm.

Operators are required to (1) perform ongoing assessments of pipeline integrity, (2) identify and characterize applicable threats to pipeline segments that could impact a HCA, (3) improve data collection, integration and analysis, (4) repair and remediate the pipeline as necessary and (5) implement preventive and mitigating actions. In compliance with the rule, we have initiated pipeline integrity testing programs that are intended to assess pipeline integrity. At this time, we cannot predict all of the effects this rule will have on us. However, the rule 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. Should we fail to comply with PHMSA rules and related regulations and orders, we could be subject to penalties and fines.

We are subject to strict regulations at many of our facilities regarding employee safety.

The workplaces associated with our pipelines are 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. The failure to comply with OSHA requirements or general industry standards, keep adequate records or monitor occupational exposure to regulated substances could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Increased competition could have a significant financial impact on us.

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 way, including the Rockies Express Pipeline that will transport natural gas from northern Colorado to eastern Ohio, the Heartland Gas Pipeline currently in operation in Indiana, the proposed Mid-Continent Express Pipeline that would transport gas from Texas to Alabama and the Southeast Header Supply System that is under construction and will transport gas from Perryville, Louisiana to markets in Florida. 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 rates, terms of service, access to gas supplies, flexibility and reliability. The FERC's policies promoting competition in gas markets are having the effect of increasing the gas transportation options for our traditional customer base. Increased competition could reduce the volumes of gas transported by our pipeline systems or, in cases where we do not have long-term fixed rate contracts, could force us to lower our transportation or storage rates. Competition could intensify the negative impact of factors that significantly decrease demand for natural gas in the markets served by our pipeline systems, such as competing or alternative forms of energy, a recession or other 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 the activities of our competitors. We also compete against a number of intrastate pipelines which have significant regulatory advantages over us and other interstate pipelines because of the absence of FERC regulation. In view of potential rate increases, construction and service flexibility available to intrastate pipelines, we may lose customers and throughput to intrastate competitors. All of these competitive pressures could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because of the natural decline in gas production from existing wells, our success depends on our ability to obtain access to new sources of natural gas and this is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business and operating results.

For the years 2003 to 2006, gas production from the Gulf Coast region, which supplies the majority of our throughput, has declined on average approximately 13.0% per year according to the Energy Information Administration. A large part of this decline was due to the effects of Hurricanes Katrina and Rita (hurricanes) in 2005. We cannot give any assurance regarding the gas production industry's ability to find new sources of domestic supply. Production from existing wells and gas supply basins connected to our pipelines will naturally decline over time, which means that our cash flows associated with the gathering or transportation of gas from these wells and basins will also decline over time. The amount of natural gas reserves underlying these wells may also be less than we anticipate, or the rate at which production from these reserves declines may be greater than we anticipate. Accordingly, to maintain or increase throughput levels on our pipelines, we must continually obtain access to new supplies of natural gas. The primary factors affecting our ability to obtain new sources of natural gas to our pipelines include: (1) the level of successful drilling activity near our pipelines, (2) our ability to compete for these supplies, (3) the successful completion of new LNG facilities near our pipelines, and (4) our gas quality requirements.

The level of drilling activity is dependent on economic and business factors beyond our control. The primary factor that impacts drilling decisions is the price of oil and natural gas. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by our pipelines, which would lead to reduced throughput levels on our pipelines. Other factors that impact production decisions include producers' capital budget limitations, the ability of producers to obtain necessary drilling and other governmental permits, the availability and cost of drilling rigs and other drilling equipment, and regulatory changes. Because of these factors, even if new natural gas reserves were discovered in areas served by our pipelines, producers may choose not to develop those reserves or may connect them to different pipelines.

Imported LNG is expected to be a significant component of future natural gas supply to the United States. Much of this increase in LNG supply is expected to be imported through new LNG facilities to be developed over the next decade. We cannot predict which, if any, of these projects will be constructed. We anticipate benefiting from some of these new projects and the additional gas supply they will bring to the Gulf Coast region. If a significant number of these new projects fail to be developed with their announced capacity, or there are significant delays in such development, or if they are built in locations where they are not connected to our systems or they do not influence sources of supply on our systems, we may not realize expected increases in future natural gas supply available for transportation through our systems.

If we are not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing supply basins, or if the expected increase in natural gas supply through imported LNG is not realized, throughput on our pipelines would decline which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Capacity leaving our Lebanon, Ohio terminus is limited.

The northeastern terminus of our Texas Gas pipeline system is in Lebanon, Ohio, where it connects with other interstate natural gas pipelines delivering to East Coast and Midwest metropolitan areas and other indirect markets. Pipeline capacity into Lebanon is approximately 48.0% greater than pipeline capacity leaving that point, creating a bottleneck for supply into areas of high demand. As of December 31, 2007, approximately 13.0% of our long-term contracts with firm deliveries to Lebanon will expire or have the ability to terminate by the end of 2008. While demand for natural gas from our Lebanon, Ohio terminus and other interconnects in that region has remained strong in the past, there can be no assurance regarding continued demand for gas from the Gulf Coast region, including East Texas, in the face of other sources of natural gas for our various indirect markets, including pipelines from Canada, the anticipated completion of the Rockies Express pipeline in late 2009 or early 2010, and new LNG facilities proposed to be constructed along the East Coast.

Successful development of LNG import terminals in the eastern United States could reduce the demand for our services.

Development of new, or expansion of existing, LNG facilities on the East Coast could reduce the need for customers in the northeastern United States to transport natural gas from the Gulf Coast and other supply basins connected to our pipelines. This could reduce the amount of gas transported by our pipelines for delivery off-system to other interstate pipelines serving the Northeast. If we are not able to replace these volumes with volumes to other markets or other regions, throughput on our pipelines would decline which could have a material adverse effect on our financial condition, results of operations and cash flows.

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, 2007, approximately 25.0% of the firm contract load on our pipeline systems, excluding agreements related to the expansion projects, was due to expire on or before December 31, 2008. 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 is the basis differential, 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 basis differentials, or market price spreads between two points on our pipelines;
- whether our business strategy continues to be successful; and
- the effects of state regulation on customer contracting practices.

Any failure to extend or replace a significant portion of our existing contracts may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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. For the year ended December 31, 2007, Atmos Energy accounted for approximately 10.0% of our total operating revenues. We may be unable to negotiate extensions or replacements of these contracts and those with other 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 financial condition, results of operations and cash flows, unless we are able to contract for comparable volumes from other customers at favorable rates.

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, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and NNS services. If any significant customer of ours should have credit or financial problems resulting in a delay or failure to repay the gas they owe us, it could have a material adverse effect on our financial condition, results of operations and cash flows. Item 7A of this Report contains more information on credit risk arising from gas loaned to customers.

If third-party pipelines and other facilities interconnected 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 can deliver approximately 500 MMcf per day to Texas Eastern at Kosciusko, Mississippi. 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 facility, lack of capacity or any other reason, our ability to continue shipping natural gas to end markets could be restricted, thereby reducing our revenues. Any temporary or permanent interruption at any key pipeline interconnect which caused a material reduction in volumes transported on our pipelines or stored at our facilities could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Significant changes in natural gas prices could affect supply and demand, reducing system throughput and adversely affecting our revenues and available cash.

Higher natural gas prices could result in a decline in the demand for natural gas, and therefore, in the throughput on our pipelines. In addition, reduced price volatility could reduce the revenues generated by our PAL and storage services and could have a material adverse effect on our financial condition, results of operations and cash flows.

In general terms, the price of natural gas fluctuates in response to changes in supply, changes in demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic conditions;
- weather conditions and seasonal trends;
- levels of domestic production and consumer demand;
- the availability of LNG;
- a material decrease in the price of natural gas could have an adverse effect on the shippers who have contracted for capacity on our planned expansion projects;
- the availability of adequate transportation capacity;
- the price and availability of alternative fuels;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of natural gas, LNG and other commodities.

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

We do not own all of the land on which our pipelines and facilities are located, and we are, therefore, subject to the risk of increased costs to maintain necessary land use. 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.

Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, or increased costs to renew such rights, could have a material adverse effect on our financial condition, results of operations and cash flows.

Mergers among our customers and/or competitors could result in lower volumes being shipped on our pipelines, thereby reducing the amount of cash we generate.

Mergers among our existing customers and/or competitors could provide strong economic incentives for the combined entities to utilize systems other than ours and we could experience difficulty in replacing lost volumes and revenues. A reduction in volumes would result not only in a reduction of revenues, but also a decline in net income and cash flows of a similar magnitude, which could reduce our ability to meet our financial obligations.

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 United States 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 energy assets, there is no assurance that we can 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.

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

At December 31, 2007, 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 Loews. 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 Loews 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:

- Loews and its affiliates may engage in competition with us.

- Neither our partnership agreement nor any other agreement requires Loews or its affiliates (other than our general partner) to pursue a business strategy that favors us. Directors and officers of Loews and its affiliates have a fiduciary duty to make decisions in the best interest of Loews 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 Loews 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, while also restricting the remedies available to our unitholders for actions that, without these limitations, might constitute breaches of fiduciary duty. By purchasing common units, unitholders are deemed to have consented 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 and the ability of the subordinated units to convert to common units.

- 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 a distribution on the subordinated units, to make incentive distributions or to accelerate the expiration of the subordination period.

- Our general partner determines which costs, including allocated overhead, incurred by it and its affiliates are reimbursable by us.

- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered on terms that are fair and reasonable to us or entering into additional contractual arrangements with any of these entities on our behalf, and provides that reimbursement to Loews for amounts allocable to us consistent with accounting and allocation methodologies generally permitted by the FERC for rate-making purposes and past business practices is deemed fair and reasonable to us.

- Our general partner intends to limit its liability regarding our contractual obligations.

- 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 80.0% of the outstanding common units or (2) all of our equity securities (including common units) if it and its affiliates own more than 50.0% in the aggregate of the outstanding common units, subordinated 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 general partner controls the enforcement of obligations owed to us by it and its affiliates.

- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

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 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 the common units depends largely on our being treated as a partnership 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 35.0%, 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 the common units.

Current 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 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. Members of Congress are considering substantive changes to the existing U.S. tax laws that affect certain publicly traded partnerships. Although the currently proposed legislation would not appear to affect our tax treatment as a partnership, we are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of an investment in our common units.

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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. Prior distributions to our unitholders in excess of the total net taxable income our unitholders were allocated for a common unit, which decreased such unitholders' tax basis in that common unit, will, in effect, become taxable income to such unitholders if the common unit is sold at a price greater than the tax basis in that common unit, even if the price our unitholders receive is less than their original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to our unitholders. In addition, upon a unitholders' sale of units, such unitholder may incur a tax liability in excess of the amount of cash it receives 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 individual retirement accounts (IRAs) and non-U.S. persons, raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and 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 United States 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 50.0% 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 eleven 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 and Gulf South are headquartered in approximately 103,000 square feet of leased office space located in Houston, Texas. Texas Gas has its headquarters in approximately 108,000 square feet of office space in Owensboro, Kentucky in a building that it owns. Our operating subsidiaries own their respective pipeline systems in fee. 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.

Item 1. "Our Business–Our Pipeline and Storage Systems," 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

Market Information

As of February 15, 2008, we had 90,656,122 common units outstanding held of record by approximately 36 holders. BPHC owns 53,256,122 of our common units and all of our subordinated units. 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 last reported sales price of our common units on the NYSE on February 15, 2008 was $29.44 per unit.

	Sales Price Range per Common Unit		Cash Distributions per Unit (a)
	High	Low	
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
Year ended December 31, 2006:			
Fourth quarter	$ 31.64	$ 25.25	$ 0.415
Third quarter	29.00	23.63	0.40
Second quarter	25.18	20.90	0.38
First quarter	22.00	17.98	0.36

(a) Represents cash distributions attributable to the quarter and declared and paid to common and subordinated unitholders within 60 days after quarter end. We also paid cash distributions to our general partner with respect to its 2.0% 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.

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, to unitholders 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

Incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of available cash from operating surplus after the minimum quarterly distribution and the subsequent target distribution levels have been achieved. Our general partner currently holds all of our incentive distribution rights, but may transfer these rights separately from its general partner interest, subject to restrictions in our partnership agreement.

Assuming we do not issue any additional classes of units and our general partner maintains its 2.0% interest, if we make distributions to our unitholders from operating surplus in an amount equal to the minimum quarterly distribution for any quarter, assuming no arrearages, then we will distribute any additional 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	
	Target Amount	Common and Subordinated Unitholders	General Partner
Minimum Quarterly Distribution	$0.3500	98.0%	2.0%
First Target Distribution	up to $0.4025	98.0%	2.0%
Second Target Distribution	above $0.4025 up to $0.4375	85.0%	15.0%
Third Target Distribution	above $0.4375 up to $0.5250	75.0%	25.0%
Thereafter	above $0.5250	50.0%	50.0%

Subordination Period

During the subordination period, holders of our common units will have the right to receive distributions of available cash from operating surplus in an amount equal to $0.35 per unit per quarter, which we refer to as the "minimum quarterly distribution," plus any arrearages, before any distributions of available cash from operating surplus may be made on the subordinated units. No arrearages will be paid on the subordinated units. Assuming there are no arrearages in payment of the minimum quarterly distribution, the subordination period will end, and all subordinated units will convert to common units, at such time as we have made distributions from operating surplus on the common and subordinated units at least equal to the minimum quarterly distribution for each of the immediately preceding three consecutive, non-overlapping four-quarter periods; provided also that the "adjusted operating surplus" (as defined in our partnership agreement) generated during such periods equaled or exceeded the sum of the minimum quarterly distributions on all of our units during such periods. Alternatively, assuming there are no arrearages, the subordination period will end at such time as we have made distributions from operating surplus on the common and subordinated units at least equal to 150.0% of the minimum quarterly distribution for the immediately preceding four-quarter period; provided also that the adjusted operating surplus generated during such period equaled or exceeded 150.0% of the minimum quarterly distributions on all of our units during such period. The subordination period will also end, and each subordinated unit will convert into one common unit, if unitholders remove our general partner other than for cause and no units held by our general partner and its affiliates are voted in favor of such removal. We have made distributions from operating surplus on our common and subordinated units in excess of the minimum quarterly distribution for the previous two consecutive, non-overlapping four-quarter periods preceding the date of this Report.

For information about our equity compensation, please see Part III, Item 12 – "Securities Authorized for Issuance under Equity Compensation Plans."

Common Unit Repurchases

On February 27, 2007, our general partner purchased 1,500 of our common units in the open market at a price of $36.61 per unit. These units were granted to our independent directors on March 5, 2007, as part of their director compensation. For information about our director compensation, please see Part III, Item 11 – "Director Compensation."

Item 6. Selected Financial Data

The following table presents summary historical financial and operating data for us and our predecessors, Boardwalk Pipelines and Texas Gas, 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. Boardwalk Pipelines was formed in April 2003 to acquire all of the outstanding capital stock of Texas Gas, the acquisition of which was completed on May 16, 2003 (the TG-Acquisition). Boardwalk Pipelines had no assets or operations prior to the TG-Acquisition; therefore, we refer to Texas Gas as their predecessor.

The TG-Acquisition was accounted for using the purchase method of accounting and, accordingly, the post-acquisition financial information included below reflects the allocation of the purchase price resulting from the acquisition. As a result, the financial statements of Texas Gas for the periods prior to May 16, 2003 are not directly comparable to our financial statements subsequent to that date. The consolidated financial and operating data shown below have been separated by a bold black line delineating our predecessor's financial data from ours.

The acquisition of Gulf South by Boardwalk Pipelines in December 2004 was also 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 ended December 31, 2004, and prior periods are not readily comparable with our results of operations for the years ended December 31, 2007, 2006 and 2005.

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 and charge-in-lieu of 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 United States of America (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 thousands, except Earnings per common and subordinated unit):

	Boardwalk Pipeline Partners, LP					Predecessor
	For the Year Ended December 31,				For the Period May 17, 2003 through December 31,	For the Period January 1, 2003 through May 16,
	2007	2006	2005	2004	2003	2003

Total operating revenues	$ 643,268	$ 607,642	$ 560,466	$ 263,621	$ 142,860	$ 113,447
Net income	227,756	197,550	100,925	48,825	22,451	34,474
Total assets	4,157,306	2,951,299	2,465,491	2,472,140	1,238,627	N/A
Long-term debt	1,847,914	1,350,920	1,101,290	1,106,135	548,115	N/A
Earnings per common and subordinated unit	$ 1.87	$ 1.85	*	N/A	N/A	N/A
EBITDA**	$ 349,839	$ 331,468	$ 289,002	$ 144,489	$ 77,241	$ 78,380

* Our net income was $35,992, or $0.35 per common and subordinated unit, for the period from November 15, 2005, the closing date of our IPO, through December 31, 2005.

**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 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 the most directly comparable GAAP financial measures, on a historical basis, as applicable, for each of the periods presented below (in thousands):

	Boardwalk Pipeline Partners, LP					Predecessor
	For the Year Ended December 31,				For the Period May 17, 2003 through December 31,	For the Period January 1, 2003 through May 16,
	2007	2006	2005	2004	2003	2003
Net income	$ 227,756	$ 197,550	$ 100,925	$ 48,825	$ 22,451	$ 34,474
Income taxes and charge-in-lieu of income taxes	769	253	49,494	32,333	15,104	22,387
Elimination of cumulative deferred taxes	-	-	10,102	-	-	-
Depreciation and amortization	81,824	75,771	72,078	33,977	20,544	16,092
Interest expense	61,023	62,123	60,067	30,081	19,368	7,392
Interest income	(21,489)	(4,202)	(1,478)	(352)	(205)	-
Interest income from affiliates, net	(44)	(27)	(2,186)	(375)	(21)	(1,965)
EBITDA	$ 349,839	$ 331,468	$ 289,002	$ 144,489	$ 77,241	$ 78,380

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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

We are a Delaware limited partnership formed to own and operate the business conducted by our operating subsidiaries, including the interstate transportation and storage of natural gas. We own and operate pipeline systems in the Gulf Coast states of Texas, Louisiana, Mississippi, Alabama, and Florida and which extend northeasterly through Arkansas to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana, and Ohio.

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 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, 2007, the percentage of our Total operating revenues associated with firm contracts was approximately 81.7%.

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 does affect our results of operations. We deliver to a broad mix of customers including LDCs, municipalities, interstate and intrastate pipelines, direct industrial users, electric power generation plants, marketers and producers. In addition to serving directly connected markets, our pipeline systems have indirect market access to the northeastern and southeastern United States through interconnections with unaffiliated pipelines.

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 affects our transportation revenues, and spreads in natural gas prices across time (for example summer to winter), which primarily affects our PAL and storage revenues. High natural gas prices in recent years have helped to drive increased production levels in producing locations such as the Bossier Sands and Barnett Shale gas producing regions in East Texas, which has resulted in additional supply being available on the west side of our system. This has resulted in widened west-to-east basis differentials which 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 being undertaken by us. Wide spreads in natural gas prices between time periods during the past two to three years, for example fall 2006 to spring 2007, were favorable for our PAL and interruptible storage services during that period. These spreads decreased substantially in 2007, which resulted in reduced PAL and interruptible storage revenues. We cannot predict future time period spreads or basis differentials.

Critical Accounting Policies and Estimates

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.

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 contractual participation rights which are incentive distribution rights in accordance with the partnership agreement 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, 2007 and 2006, were adjusted to take into account an assumed incremental allocation to the general partner's incentive distribution rights. Payments made on account of the incentive distribution rights are determined in relation to actual declared distributions.

Regulation

Under the FERC's 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 considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. At December 31, 2007 and 2006, there were no liabilities for any open rate case recorded on our Consolidated Balance Sheets. Currently, neither of our operating subsidiaries is involved in an open general rate case.

SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, requires rate-regulated public utilities to account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. In applying SFAS No. 71, Texas Gas records certain costs and benefits as regulatory assets and liabilities, respectively, in order to provide for recovery from or refund to customers in future periods. Gulf South does not apply SFAS No. 71, because certain services provided by it are priced using market-based rates and competition in its market area can result in discounts from the maximum allowable cost-based rates being granted to customers, such that the application of SFAS No. 71 is not appropriate.

The storage facilities operated by our operating subsidiaries store gas that is owned by them as well as gas owned by customers. Due to its method of accounting for storage, volumes held on behalf of others by Gulf South are not reflected on the Consolidated Balance Sheets. Consistent with the method of storage accounting elected by Texas Gas and the risk-of-loss provisions included in its tariff, Texas Gas reflects an equal and offsetting receivable and payable for certain customer-owned gas in its facilities for certain storage and related services. For further discussion of our gas in storage, please see Note 2 in Item 8 of this Report.

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, 2007, we had accrued approximately $17.0 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, the FERC and other governmental authorities on these matters. We continue to conduct environmental assessments and are implementing a variety of remedial measures that may result in increases or decreases in the total estimated environmental costs.

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Impairment

At June 30, 2007, the carrying value of our Magnolia storage expansion project was tested for impairment. As a result of the impairment test, we recognized a $14.7 million impairment charge representing the carrying value of the storage cavern. In determining that the fair value of the cavern was zero, estimates and assumptions were made regarding the cash flows associated with the storage cavern disposal through sale or abandonment. Certain costs remain inestimable related to potential regulatory or contractual obligations associated with abandonment of the storage cavern. We believe that alternative uses for the storage cavern may be possible in the hands of a third-party, and will pursue these options with the lessor, however, we have assumed no future cash flows related to these options in our impairment analysis. In assessing the carrying value of the other associated facilities which include pipeline, compressors and other equipment and facilities, we assumed that the facilities would be used in conjunction with a replacement storage cavern to be developed. Our expected cash flows related to the other facilities include the cost of developing a new cavern and revenues from the sale of storage services to third-parties over the useful life of the asset. If storage spreads were to compress appreciably or significant difficulties were to arise in the development of the cavern, the actual cash flows could differ materially from the expected cash flows used in assessing the carrying value of the facilities which could result in the recognition of an additional impairment charge. If it is determined in the future that the assets cannot be used in conjunction with a new cavern, we may be required to record an additional impairment charge at the time that determination is made.

Jackson Storage Gas Loss

Our Jackson, Mississippi aquifer storage facility has a working gas capacity of approximately 5.0 Bcf and is primarily used for operational purposes. In the fourth quarter 2007, it was determined that, based upon tests used to estimate the amount of gas stored in the facility, gas loss had occurred in the range of 1.3 to 1.7 Bcf. As a result of the estimated gas loss, we recognized a charge of $0.7 million to Operation and maintenance expense in the fourth quarter 2007. This amount was determined by applying the carrying value of gas in the facility of $0.53 per million British thermal units (MMBtu), to the low end of the range of estimated gas loss of 1.3 Bcf. An assessment is underway to determine whether the gas will need to be replaced in order to operate the facility and support pipeline operations. A more comprehensive test of the field will be performed in the second quarter 2008. If the pending test results indicate that the actual gas loss is greater than the estimated 1.3 Bcf, this could result in a future adjustment to the estimate.

Goodwill

As of December 31, 2007, 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, 2007, 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 United States 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 9 in Item 8 of this Report.

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. Item 1, Nature of Contracts, contains more information about the nature of our revenues. Our operating costs and expenses typically do not vary significantly based upon the amount of gas transported, with the exception of fuel consumed at Gulf South’s compressor stations, which is part of Operation and maintenance expenses. We charge shippers for fuel in accordance with each pipeline’s individual tariff guidelines and Gulf South’s fuel recoveries are included as part of Gas transportation revenues. The following analysis discusses our financial results of operations for the years 2007, 2006 and 2005.

2007 Compared with 2006

Our net income for the year ended December 31, 2007, increased $30.2 million, or 15.3%, from 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 storage gas associated with a storage expansion project, which was accounted for as a reduction of operating expenses.

Total operating revenues increased $35.7 million, or 5.9%, to $643.3 million for the year ended December 31, 2007, compared to $607.6 million for the year ended December 31, 2006, primarily due to:

- $23.4 million increase in gas transportation fees due to higher reservation rates, including $8.9 million from new contracts associated with the Carthage, Texas to Keatchie, Louisiana pipeline expansion which was in service for all of 2007;
- $11.9 million increase in fuel revenues due to increased retained volumes from higher system utilization including amounts associated with pipeline expansion; and
- $4.1 million increase from the settlement of a claim related to a firm transportation agreement in the Calpine bankruptcy proceeding.

Operating costs and expenses increased $23.5 million, or 6.6%, to $377.2 million for the year ended December 31, 2007, compared to $353.7 million for the year ended December 31, 2006, primarily due to:

- $14.7 million loss from impairment of the Magnolia storage facility in the second quarter 2007;
- $9.3 million in charges associated with offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, including $4.8 million related to re-covering the pipeline and a $4.5 million impairment charge;
- $6.9 million increase in fuel costs due to an increase in gas usage;
- $6.0 million increase in depreciation and amortization from increases in our asset base;
- $5.0 million increase in property and other taxes due to increases in the valuation of our asset base;
- $3.8 million increase related to termination of an agreement with a construction contractor on the Southeast expansion project; and
- $22.0 million decrease from a 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 33.2%, to $37.5 million for the year ended December 31, 2007, compared to $56.1 million for the year ended December 31, 2006. The decline is 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.

2006 Compared with 2005

Our net income for the year ended December 31, 2006 increased $96.6 million or 95.7% from 2005. The primary drivers for the increase were higher PAL, gas storage and gas transportation revenues and a change in tax status concurrent with our IPO in November 2005, as a result of which we ceased recording a charge-in-lieu of income taxes in our results of operations.

Total operating revenues increased $47.2 million, or 8.4%, to $607.6 million for the year ended December 31, 2006, compared to $560.4 million for the year ended December 31, 2005, primarily due to:

- $38.5 million increase in gas storage and PAL revenues mainly due to favorable natural gas price spreads and volatility in forward natural gas prices;
- $26.0 million increase in firm transportation revenues, excluding fuel, primarily due to higher reservation rates and additional capacity reserved by shippers due to increased production in the East Texas region; and
- $5.3 million increase due mainly to hurricane insurance recoveries received in 2006 and gas lost in 2005 related to hurricanes.

The increases were partly offset by:

- $10.5 million decrease in interruptible transportation revenues due in part to customers shifting to firm services and supply disruptions caused by the hurricanes;
- $7.1 million decrease in fuel retained due to lower realized natural gas prices and reduced throughput; and
- $5.5 million decrease in revenues from the amortization of acquired executory contracts.

Operating costs and expenses increased by $8.7 million, or 2.5%, to $353.7 million for the year ended December 31, 2006, compared to $345.0 million for the year ended December 31, 2005. This increase is primarily due to:

- $12.6 million increase in outside services and overheads mainly due to growth in operations and regulatory compliance;
- $12.2 million from the sale of storage gas related to Phase I of our Western Kentucky storage expansion project reported in Net gain on disposal of operating assets and related contracts in 2005;

- $10.2 million higher employee benefits costs comprised mainly of $6.3 million from the amortization of a regulatory asset for postretirement benefits as a result of the Texas Gas rate case settlement and $3.5 million from a special termination benefit charge recorded as a result of the early retirement incentive program; and
- $3.7 million from an increase in depreciation and amortization due to increases in our asset base and $2.6 million increased expense from the lease of third-party pipeline capacity.

The increases were partly offset by:

- $18.2 million decrease in hurricane-related costs from $7.3 million of hurricane-related insurance recoveries recognized in 2006 and a reduction in hurricane-related operating expenses from amounts incurred in 2005;
- $14.9 million decrease in company-used gas due to operational efficiencies, lower natural gas prices and reduced throughput resulting in decreased usage.

Total other deductions increased by $1.2 million, or 2.2%, of which $2.1 million is primarily due to interest expense related to borrowings under our revolving credit facility and the issuance of new debt in November 2006, offset by an increase in interest income.

Liquidity and Capital Resources

We are a partnership holding company and derive all of our operating cash flow from our operating subsidiaries. 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.

Our operating subsidiaries participate in a 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.

Maintenance Capital Expenditures

Maintenance capital expenditures were $47.1 million, $41.7 million and $52.9 million in 2007, 2006 and 2005. We expect to fund our 2008 maintenance capital expenditures of approximately $60.0 million from our operating cash flows.

Expansion Capital Expenditures

Expansion capital expenditures were $1,162.7 million, $158.6 million and $30.1 million in 2007, 2006 and 2005. As discussed above in Item 1, Business – Expansion Projects, we have undertaken significant capital expansion projects, substantially all of which have been or are expected to be funded with proceeds from equity and debt financings.

Since our IPO through December 31, 2007, we have raised $726.0 million through issuances of equity limited partnership units and contributions from our general partner and $743.6 million through issuances of unsecured notes by us and our subsidiaries, as described below under Equity and Debt Financing, and in Note 7 to the consolidated financial statements contained in Item 8 of this Report. At December 31, 2007, we had approximately $317.3 million in cash and $814.4 million of borrowing capacity available under our $1.0 billion revolving credit facility discussed below.

We expect to incur expansion capital expenditures of approximately $3.1 billion in 2008 and approximately $0.2 billion in 2009 to complete our pipeline expansion projects, based upon our current cost estimates. However, as noted elsewhere in this report, we have experienced cost increases in these projects and various factors could cause our costs to exceed that amount. We expect to finance our remaining pipeline expansion capital costs through equity financings and the incurrence of debt, including sales of debt by us and our subsidiaries, and borrowings under our revolving credit facility, as well as available operating cash flow in excess of our operating needs. However, the impact of the cost increases we have experienced and may experience in the future to complete our expansion capital projects could adversely impact our financing costs, which could have a material adverse affect on our results of operations, financial condition and cash flows. See Item 1A, Risk Factors – We are undertaking large, complex expansion projects which involve significant risks that may adversely affect our business. See also Item 1 – Pipeline Expansion Projects.

Equity and Debt Financing

In November 2007, we completed an offering of 7.5 million of our common units at a price of $30.90 per unit. The offering resulted in net proceeds of $232.8 million, after deducting underwriting discounts and offering expenses of $3.7 million and including $4.7 million received from our general partner to maintain its 2.0% interest in us. After the offering, we have 90.7 million common units and 33.1 million subordinated units issued and outstanding, of which 37.4 million common units are held by the public.

In August 2007, we sold $225.0 million of 5.75% senior unsecured notes of Gulf South due August 15, 2012, and $275.0 million of 6.30% senior unsecured notes of Gulf South due August 15, 2017. We received net proceeds of approximately $495.3 million after deducting initial purchaser discounts and offering expenses of $4.7 million.

In March 2007, we completed a public offering of 8.0 million of our common units at a price of $36.50 per unit. We received proceeds of approximately $293.8 million, net of underwriting discounts and offering expenses of $4.2 million and including approximately $6.0 million from the general partner to maintain its 2.0% general partner interest.

The proceeds of these offerings have been and will be primarily used to fund capital expenditures associated with our expansion projects.

In August 2007, we 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 reference rate on the Treasury rate lock was 4.74%. On February 1, 2008, we paid the counterparty approximately $15.0 million to settle the rate lock. The Treasury lock was designated as a cash flow hedge in accordance with SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended; therefore the loss will be recognized in Interest expense over the term of the related debt to be issued.

Credit Facility

We maintain a $1.0 billion revolving credit facility, which was increased from $700.0 million in November 2007, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. 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 (LIBOR) or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. Under the terms of the agreement, each of the borrowers must maintain a minimum ratio, as of the last day of each fiscal quarter, of consolidated total debt to consolidated earnings before income taxes, depreciation and amortization (as defined in the agreement), measured for the preceding twelve months, of not more than five to one. As of December 31, 2007, we were in compliance with all the covenant requirements under our credit agreement and no funds were drawn under this facility. However, at December 31, 2007, we had outstanding letters of credit under the facility for $185.6 million to support certain obligations associated with the Fayetteville Lateral and Gulf Crossing expansion projects which reduced the available capacity under the facility by such amount. The revolving credit facility has a maturity date of June 29, 2012.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations as of December 31, 2007, 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	$ 1,860.0	-	-	$ 225.0	$ 1,635.0
Interest on long-term debt	963.7	$ 103.6	$ 207.4	207.4	445.3
Capital commitments	851.1	834.7	16.4	-	-
Lease commitments	36.7	6.7	10.8	6.0	13.2
Total	$ 3,711.5	$ 945.0	$ 234.6	$ 438.4	$ 2,093.5

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. The above table does not reflect commitments we have made after December 31, 2007, relating to our expansion projects. For information on these projects, please read "Capital Expenditures" above.

Changes in cash flow from operating activities

Net cash provided by operating activities increased $26.2 million, or 10.3%, to $281.7 million for the year ended December 31, 2007, compared to $255.5 million for the comparable 2006 period, primarily due to:

- $16.0 million increase in cash due to gas purchases made in 2006;
- $8.5 million increase in cash due to the timing of expenditures; and
- $3.0 million increase in cash from the change in net income, excluding non-cash items such as depreciation and amortization, impairment charges and recognition of previously deferred revenues.

Changes in cash flow from investing activities

Net cash used in investing activities increased $988.8 million to $1.2 billion for the year ended December 31, 2007, compared to $191.5 million for the comparable 2006 period, primarily due to an increase in capital expenditures mainly for our expansion projects.

Changes in cash flow from financing activities

Net cash provided by financing activities increased $547.7 million to $816.9 million for the year ended December 31, 2007, compared to $269.2 million for the comparable 2006 period, primarily due to:

- $327.2 million increase in net proceeds from the sale of common units and related general partner capital contributions;
- $157.0 million increase in net proceeds from the issuance of long term debt; and
- $132.1 million decrease in cash used from the payment of notes and other long term debt in 2006.

These increases were partly offset by $68.6 million increase in cash distributions to unitholders and the general partner.

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 and maintenance costs. 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, limit our ability to price jurisdictional services or products to ensure recovery of inflation's effect on costs.

Off-Balance Sheet Arrangements

At December 31, 2007, 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.

Recent Accounting Pronouncements

For a discussion regarding recent accounting pronouncements, please read Note 15 in Item 8 of this Report.

Calpine Energy Services (Calpine) Settlement

In 2002 and 2003, Calpine entered into two 20-year transportation agreements with Gulf South. In December 2005, Calpine filed for Chapter 11 Bankruptcy protection and in early 2006 discontinued making payments on one of the transportation agreements. Gulf South continued to invoice Calpine under the transportation agreements and fully reserved the revenues associated with the contract on which Calpine was not making payments. In December 2007, Gulf South and Calpine filed a stipulation and agreement with the Bankruptcy court, which was approved in January 2008, to terminate the firm transportation agreement on which Calpine was delinquent, and to settle all of Gulf South's claims in the Bankruptcy proceedings for approximately $16.5 million. The claim was to be paid in the form of Calpine stock, along with other general creditors having claims in the Bankruptcy proceeding. In January 2008, we sold the Bankruptcy claim to a third party and received a cash payment of approximately $15.3 million. The assignment is with recourse subject to the issuance of Calpine stock in the full amount of the claim. As a result of the settlement, in 2007 we recognized $4.1 million in Gas transportation revenues related to invoiced amounts past due, which were previously reserved. The remainder of the settlement amount will be recognized upon full payment of the settlement amount by Calpine.

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 project, 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, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages, expansion costs that are higher than anticipated and numerous other factors beyond our control.
- We may not complete any future debt or equity financing transaction.
- The gas transmission and storage operations of our subsidiaries are subject to rate-making policies and actions by the FERC or customers that could have an adverse impact on the rates we charge and our ability to recover our income tax allowance, our full cost of operating our pipelines and 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 could negatively 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.
- Successful development of LNG import terminals in the eastern or northeastern United States could reduce the demand for our services.
- 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

Our debt has been issued at fixed rates, therefore interest expense would not be impacted by changes in interest rates. Total long-term debt at December 31, 2007, had a carrying value of $1.8 billion and a fair value of $1.8 billion. A 100 basis point increase in interest rates on our fixed rate debt would result in a decrease in fair value of approximately $118.8 million at December 31, 2007. A 100 basis point decrease would result in an increase in fair value of approximately $129.3 million at December 31, 2007. The weighted-average interest rate of our long-term debt was 5.82% at December 31, 2007.

In August 2007, we 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 reference rate on the rate lock was 4.74%. On February 1, 2008, we paid the counterparty approximately $15.0 million to settle the rate lock. The Treasury lock was designated as a cash flow hedge in accordance with SFAS No. 133, therefore the loss will be recognized in Interest expense over the term of the related debt to be issued.

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2007, approximately $16.3 million of gas stored underground, which we own and carry as current Gas stored underground, is exposed to commodity price risk. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas.

In the second quarter 2007, we 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 our Gulf Crossing and Southeast expansion projects, approximately 1.3 Bcf of which remained outstanding at December 31, 2007. The derivatives were not designated as hedges in accordance with SFAS No. 133 and were marked to fair value through earnings resulting in a loss of $1.0 million for the year ended December 31, 2007. Changes in the fair value of the derivatives will be recognized in earnings each quarter until settlement. When the gas is purchased, the ultimate cost will be recorded to Property, Plant and Equipment and recognized in earnings as the property is depreciated. A $1.00 increase in the price of NYMEX natural gas futures would result in the recognition of a $1.3 million gain in earnings. Conversely, a $1.00 decrease would result in the recognition of a $1.3 million loss.

With the exception of the derivatives related to line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas, cash for fuel reimbursement and debt issuance 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 contracts designated as cash flow hedges are deferred as a component of accumulated other comprehensive income. The deferred gains and losses are recognized in the Consolidated Statements of Income when the anticipated transactions affect earnings. Generally, for gas sales and cash for fuel reimbursement, any gains and losses on the related derivatives would be recognized in Operating Revenues. 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 we measure 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.

We are exposed to credit risk relating 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, as well as volumes owed by customers for imbalances or gas lent by us to them, generally under PAL and NNS. We maintain credit policies intended to minimize credit risk and actively monitor these policies. Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. As of December 31, 2007, the amount of gas loaned out by our subsidiaries was 12.7 trillion British thermal units (TBtu) and, assuming an average market price during December 2007 of $7.13 per MMBtu, the market value of gas loaned out at December 31, 2007, would have been approximately $90.6 million. 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, 2007, our cash and cash equivalents were invested primarily in mutual funds. Due to the short-term nature and type of our investments, a hypothetical 10.0% increase in interest rates would not have a material effect on the fair market value of our portfolio. Since we have the ability to liquidate this portfolio, we do not expect our Consolidated Statements of Income or Cash Flows to be materially impacted by the effect of a sudden change in market interest rates on our investment portfolio.

During 2007, we began investing in short-term investments such as 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 owed by the counterparty. We had no investments under repurchase agreements at December 31, 2007, however since then we have reinitiated our program of investing in short-term repurchase agreements.

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, 2007 and 2006, and the related consolidated statements of income, member's equity and partners' capital, comprehensive income, and cash flows for each of the three years in the period ended December 31, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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.

As discussed in Note 1 to the consolidated financial statements, the accompanying financial statements reflect a change in the Partnership's tax status.

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, 2007, 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 26, 2008 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 26, 2008

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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, 2007, 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 Annual 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, 2007, 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, 2007 of the Partnership and our report dated February 26, 2008 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding a change in the Partnership's tax status.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 26, 2008

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

ASSETS	December 31, 2007	December 31, 2006
Current Assets:		
Cash and cash equivalents	$ 317,319	$ 399,032
Receivables:		
Trade, net	60,661	54,082
Other	12,748	12,759
Gas Receivables:		
Transportation and exchange	12,467	9,115
Storage	1,266	11,704
Inventories	16,581	14,110
Costs recoverable from customers	6,358	11,236
Gas stored underground	16,322	14,001
Prepaid expenses and other current assets	11,927	22,117
Total current assets	455,649	548,156
Property, Plant and Equipment:		
Natural gas transmission plant	2,392,503	1,832,006
Other natural gas plant	223,952	213,926
	2,616,455	2,045,932
Less—accumulated depreciation and amortization	262,477	187,412
	2,353,978	1,858,520
Construction work in progress	951,433	165,916
Property, plant and equipment, net	3,305,411	2,024,436
Other Assets:		
Goodwill	163,474	163,474
Gas stored underground	172,438	161,537
Costs recoverable from customers	15,870	19,767
Other	44,464	33,929
Total other assets	396,246	378,707
Total Assets	$ 4,157,306	$ 2,951,299

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars, except number of units)

LIABILITIES AND PARTNERS' CAPITAL	December 31, 2007	December 31, 2006
Current Liabilities:		
Payables:		
Trade	$ 190,639	$ 56,604
Affiliates	1,292	3,014
Other	5,089	14,459
Gas Payables:		
Transportation and exchange	17,849	15,485
Storage	35,250	42,127
Accrued taxes, other	20,164	16,082
Accrued interest	30,801	19,376
Accrued payroll and employee benefits	22,337	18,198
Construction retainage	32,195	2,336
Deferred income	7,235	22,147
Other current liabilities	26,459	18,590
Total current liabilities	389,310	228,418
Long –Term Debt	1,847,914	1,350,920
Other Liabilities and Deferred Credits:		
Pension and postretirement benefits	17,211	15,761
Asset retirement obligation	16,059	14,307
Provision for other asset retirement	42,380	39,644
Other	41,430	29,742
Total other liabilities and deferred credits	117,080	99,454
Commitments and Contingencies		
Partners' Capital:		
Common units - 90,656,122 and 75,156,122 common units issued and outstanding as of December 31, 2007 and 2006	1,473,924	941,792
Subordinated units - 33,093,878 units issued and outstanding as of December 31, 2007 and 2006	291,662	285,543
General partner	33,204	22,060
Accumulated other comprehensive income, net of tax	4,212	23,112
Total partners' capital	1,803,002	1,272,507
Total Liabilities and Partners' Capital	$ 4,157,306	$ 2,951,299

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF INCOME
(Thousands of Dollars, except earnings per unit and number of units)

	For the Year Ended December 31, 2007	2006	2005
Operating Revenues:			
Gas transportation	$ 529,717	$ 508,241	$ 505,148
Parking and lending	42,793	49,163	21,426
Gas storage	39,429	32,396	21,667
Other	31,329	17,842	12,225
Total operating revenues	643,268	607,642	560,466
Operating Costs and Expenses:			
Operation and maintenance	173,759	161,279	174,641
Administrative and general	97,039	97,298	78,752
Depreciation and amortization	81,824	75,771	72,078
Taxes other than income taxes	29,162	24,175	27,361
Asset impairment	19,218	-	-
Net gain on disposal of operating assets and related contracts	(23,767)	(4,829)	(7,846)
Total operating costs and expenses	377,235	353,694	344,986
Operating income	266,033	253,948	215,480
Other Deductions (Income):			
Interest expense	61,023	62,123	60,067
Interest income	(21,489)	(4,202)	(1,478)
Interest income from affiliates, net	(44)	(27)	(2,186)
Miscellaneous other income, net	(1,982)	(1,749)	(1,444)
Total other deductions	37,508	56,145	54,959
Income before income taxes	228,525	197,803	160,521
Income taxes and charge-in-lieu of income taxes *	769	253	49,494
Elimination of cumulative deferred taxes *	-	-	10,102
Net income *	$ 227,756	$ 197,550	$ 100,925

*Results of operations for the year ended December 31, 2005, reflect a change in the tax status associated with Boardwalk Pipeline Partners, LP and Boardwalk Pipelines coincident with the IPO. Boardwalk Pipeline Partners, LP recorded a charge-in-lieu of income taxes and certain state franchise taxes for the period January 1, 2005 through the date of the offering. Pursuant to the change in tax status, Boardwalk Pipeline Partners, LP also eliminated its balance of accumulated deferred income taxes at the date of the offering (as presented in line item "Elimination of cumulative deferred taxes"). The subsidiaries of Boardwalk Pipeline Partners, LP directly incur some income-based state taxes following the date of the offering. See Note 1 to the consolidated financial statements for additional information.

Calculation of limited partners' interest in Net income:	For the Year Ended December 31,	For the Period November 15, 2005

	2007	2006	through December 31, 2005
Net income	$ 227,756	$ 197,550	$ 35,992
Less general partner's interest in Net income	7,030	3,951	720
Limited partners' interest in Net income	$ 220,726	$ 193,599	$ 35,272
Basic and diluted net income per limited partner unit:			
Common and subordinated units	$ 1.87	$ 1.85	$ 0.35
Cash distribution to common and subordinated unitholders	$ 1.74	$ 1.32	-
Weighted-average number of limited partners units outstanding:			
Common units	82,510,917	68,977,766	68,256,122
Subordinated units	33,093,878	33,093,878	33,093,878

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Thousands of Dollars)

	For the Year Ended December 31, 2007	2006	2005
OPERATING ACTIVITIES:			
Net income	$ 227,756	$ 197,550	$ 100,925
Adjustments to reconcile to cash provided by operations:			
Depreciation and amortization	81,824	75,771	72,078
Amortization of deferred costs	8,319	8,758	1,313
Amortization of acquired executory contracts	(1,098)	(3,997)	(9,630)
Provision for deferred income taxes	(17)	(39)	54,682
Asset impairment	19,218	-	-
Gain on disposal of operating assets and related contracts	(23,767)	(4,829)	(7,846)
Changes in operating assets and liabilities:			
Trade and other receivables	(4,141)	(436)	(27,257)
Gas receivables and storage assets	5,446	21,451	(25,474)
Costs recoverable from customers	3,598	(3,968)	(8,215)
Other assets	(15,816)	(15,583)	32,259
Trade and other payables	(15,960)	9,117	(7,461)
Gas payables	(17,935)	(45,066)	35,567
Accrued liabilities	12,929	(8,091)	21,467
Other liabilities	1,347	24,850	(13,694)
Net cash provided by operating activities	281,703	255,488	218,714
INVESTING ACTIVITIES:			
Capital expenditures	(1,209,848)	(200,330)	(82,955)
Proceeds from sale of operating assets	28,741	3,646	4,725
Proceeds from insurance reimbursements and other recoveries	1,726	5,928	4,177
Advances to affiliates, net	(945)	(696)	(28,252)
Net cash used in investing activities	(1,180,326)	(191,452)	(102,305)
FINANCING ACTIVITIES:			
Proceeds from notes payable	-	-	42,100
Payments of notes payable	-	(42,100)	(250,000)
Proceeds from long-term debt, net of issuance costs	495,271	338,307	569,369
Payment of long-term debt	-	(90,000)	(575,000)
Distributions	(204,950)	(136,388)	(131,686)
Proceeds from sale of common units, net of related transaction costs	515,900	195,209	271,398
Capital contribution from parent and general partner	10,689	4,176	6,684
Net cash provided by (used in) financing activities	816,910	269,204	(67,135)
(Decrease) increase in cash and cash equivalents	(81,713)	333,240	49,274
Cash and cash equivalents at beginning of period	399,032	65,792	16,518
Cash and cash equivalents at end of period	$ 317,319	$ 399,032	$ 65,792

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

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BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY AND PARTNERS' CAPITAL
(Thousands of Dollars, except units)

	Paid in Capital	Retained Earnings	Accumulated Other Comp Income (Loss)	Common Units	Subordinated Units	General Partner	Total Partners' Capital
Balance January 1, 2005	$ 1,071,651	$ 21,276	-	-	-	-	-
Add (deduct):							-
Net income	-	64,933	-	-	-	-	-
Capital contribution	6,684	-	-	-	-	-	-
Dividends paid	-	(233,087)	-	-	-	-	-
Other comprehensive income, net of tax	-	-	$ 287	-	-	-	-
Elimination of deferred taxes on accumulated other comprehensive income	-	-	64	-	-	-	-
Balance November 15, 2005	$ 1,078,335	$ (146,878)	$ 351	-	-	-	-
Boardwalk Pipeline Partners, LP							
Add (deduct):							
Capital contribution, including assumption of debt of $250.0 million (53,256,122 common units, 33,093,878 subordinated units and 2% general partner interest)	-	-	$ 351	$ 410,456	$ 255,061	$ 15,941	$ 681,809
Sale of common units, net of related transaction costs (15,000,000 units)	-	-	-	271,398	-	-	271,398

Other comprehensive loss, net of tax	-	-	(525)	-	-	-	(525)
Net income	-	-	-	23,755	11,517	720	35,992
Balance December 31, 2005	-	-	$ (174)	$ 705,609	$ 266,578	$ 16,661	$ 988,674
Add (deduct):							
Net income	-	-	-	130,990	62,609	3,951	197,550
Distributions paid	-	-	-	(90,016)	(43,644)	(2,728)	(136,388)
Sale of common units, net of related transaction costs (6,900,000 units)	-	-	-	195,209	-	-	195,209
Capital contribution	-	-	-	-	-	4,176	4,176
Other comprehensive income, net of tax	-	-	8,483	-	-	-	8,483
Adjustment to initially apply SFAS No. 158, net of tax	-	-	14,803	-	-	-	14,803
Balance December 31, 2006	-	-	$ 23,112	$ 941,792	$ 285,543	$ 22,060	$ 1,272,507
Add (deduct):							
Net income	-	-	-	157,189	63,537	7,030	227,756
Distributions paid	-	-	-	(140,957)	(57,418)	(6,575)	(204,950)
Sale of common units, net of related transaction costs (15,500,000 units)	-	-	-	515,900	-	-	515,900
Capital contribution from general partner	-	-	-	-	-	10,689	10,689
Other comprehensive loss, net of tax	-	-	(18,900)	-	-	-	(18,900)
Balance December 31, 2007	-	-	$ 4,212	$ 1,473,924	$ 291,662	$ 33,204	$ 1,803,002

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of Dollars)

	For the Year Ended December 31, 2007	2006	2005
Net income	$ 227,756	$ 197,550	$ 100,925
Other comprehensive (loss) income:			
(Loss) gain on cash flow hedges	(9,864)	19,405	(2,735)
Reclassification adjustment transferred to Net income from cash flow hedges	(7,336)	(10,922)	2,561
Pension and other postretirement benefits costs	(1,700)	-	-
Total comprehensive income	$ 208,856	$ 206,033	$ 100,751

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 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). Boardwalk Pipelines Holding Corp. (BPHC) a wholly-owned subsidiary of Loews Corporation (Loews) owns 53.3 million common units and 33.1 million subordinated units constituting approximately 70.0% of the Partnership's equity. Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC is the Partnership's general partner and holds a 2.0% general partner interest and all of the incentive distribution rights, further described in Note 10. 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).

In connection with the consummation of the Partnership's initial public offering (IPO), BPHC contributed all of the equity interests of Boardwalk Pipelines to the Partnership. 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 the results of the Partnership subsequent to November 15, 2005, as the consolidated results of the Partnership.

Results of operations for the year ended December 31, 2005, reflect a change in the tax status associated with the Partnership and Boardwalk Pipelines, coincident with the IPO. Prior to 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. Accordingly, the Partnership recorded a charge-in-lieu of income taxes of $49.5 million for the period January 1, 2005, through the date of the offering. Pursuant to the change in tax status, the Partnership also eliminated its balance of accumulated deferred income taxes at the date of the offering as presented in Elimination of cumulative deferred taxes on the Consolidated Statements of Income. The subsidiaries of the Partnership directly incur some income-based state taxes which are presented in Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

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 South, Texas Gas and Gulf Crossing Pipeline Company, LLC (Gulf Crossing) 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, revenues subject to refund, and prior to converting to a limited partnership, charge-in-lieu of income taxes. 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. 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 and Illinois, with 13,550 miles of pipelines and integrated storage fields.

Cash and Cash Equivalents

Cash equivalents are highly liquid investments with an original maturity of three months or less. Cash equivalents are stated at cost plus accrued interest, which approximates 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. The Partnership had no restricted cash at December 31, 2007 and 2006.

Cash Management and Advances to Affiliates

The operating subsidiaries participate in a cash management program to the extent they are permitted under Federal Energy Regulatory Commission (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 Partnership also periodically pays for certain taxes on behalf of BPHC. The obligations to repay these amounts 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.

Inventories

Inventories consisting of materials and supplies are carried at the lower of average cost or market, less an allowance for obsolescence.

Gas in Storage and Gas Receivables/Payables

Both operating subsidiaries have underground gas in storage which is utilized for system management and operational balancing, as well as for certain tariff services including firm, interruptible and no-notice (NNS) storage 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.

The accompanying consolidated financial statements reflect the balance of underground gas in storage recorded at historical cost, as well as the resulting activity relating to the storage services and balancing activity. Gas stored underground includes natural gas volumes owned by the pipelines, at times reduced by certain operational encroachments upon that gas. Current gas stored underground represents retained fuel and excess working gas which is available for resale and is valued at the lower of weighted-average cost or market. Retained fuel is a component of Gulf South's tariff structure and is recognized as transportation revenue at market prices in the month of retention. Customers can pay Gulf South's fuel rate by physically delivering gas or making a cash payment.

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 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. For Gulf South, these receivables and payables are valued at market price. For Texas Gas, these amounts are valued at the historical value of gas in storage, consistent with the regulatory treatment and the settlement history.

Due to the method of storage accounting elected by Gulf South, the Partnership does not reflect volumes held by Gulf South on behalf of others on its Consolidated Balance Sheets. As of December 31, 2007 and 2006, Gulf South held 52.0 trillion British thermal units (TBtu) and 61.0 TBtu of gas owned by shippers, and had loaned 0.2 TBtu of gas to shippers as of December 31, 2007. No gas was loaned by Gulf South to shippers as of December 31, 2006. Consistent with the method of storage accounting elected by Texas Gas and the risk-of-loss provisions included in its tariff, Texas Gas reflects an equal and offsetting receivable and payable for customer-owned gas in its facilities for storage and related services. The amount reflected in Gas Payables on the Consolidated Balance Sheets is valued at a historical cost of gas of $36.6 million and $45.7 million at December 31, 2007 and 2006.

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 the Consolidated Statements of Income 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.

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.

Gulf South depreciates assets 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 property in the Gulf South system could result in a gain or loss. Depreciation at Texas Gas 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 Texas Gas generally do not impact PPE, net.

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 the assets is compared to the carrying value of the assets 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. Note 4 contains more information regarding the Partnership’s PPE.

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 2007, 2006 or 2005.

Regulatory Accounting

The operating subsidiaries are regulated by FERC. SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, requires that rate-regulated entities that meet certain specified criteria account for and report assets and liabilities consistent with the economic effect of the manner in which independent third-party regulators establish rates. Gulf South does not apply SFAS No. 71. Certain services provided by Gulf South are market-based and competition in its market area has often resulted in discounts from the maximum allowable cost-based rates being granted to customers, such that SFAS No. 71 has not been appropriate. Therefore, Gulf South does not record any regulatory assets or liabilities. Texas Gas applies SFAS No. 71. Therefore, certain costs and benefits are recorded as regulatory assets and liabilities based on expected recovery from customers or refund to customers in future periods.

The Partnership monitors the regulatory and competitive environment in which it operates to determine that the regulatory assets continue to be probable of recovery. If the Partnership were to determine that all or a portion of these 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.

Acquired Executory Contracts

As a result of the Gulf South acquisition in December 2004, the Partnership recorded certain shipper contracts at fair value. The below-market valuation balance of $0.2 million and $1.3 million as of December 31, 2007 and 2006 was included as a component of Other current liabilities At the date of acquisition, these deferred credits were to be amortized over the life of the shipper contracts ranging from three months to three years. Amortization for 2007, 2006 and 2005 was $1.1 million, $4.0 million and $9.6 million and is expected to be $0.2 million for 2008.

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 (ARO) in the period during which the liability is incurred. The liability is initially recognized at fair value and is increased with the passage of time as accretion expense is recorded, until the liability is ultimately settled. Corresponding retirement costs are capitalized as part of the carrying amount of the related long-lived asset and depreciated over the useful life of the 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 is remeasured each reporting period until settlement, and recognizes it as compensation expense over the period the employee is required to provide service in exchange for the award, usually the vesting period. 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 9 contains additional information regarding the Partnership's unit-based compensation.

Revenue Recognition

The maximum rates that may be charged by the operating subsidiaries for their gas transportation and storage services are established through the FERC cost-based rate-making process. Rates charged by the operating subsidiaries may be less than those allowed by the 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 $7.2 million at December 31, 2007, related to PAL services to be provided mainly in 2008. At December 31, 2006, the Partnership had deferred revenues of $22.4 million.

Retained fuel is a component of Gulf South's tariff structure and is recognized in revenues at market prices in the month of retention. The related fuel consumed in providing transportation services is recorded as a component of Operation and maintenance expense 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, 2007, 2006 and 2005 were $73.0 million, $73.2 million and $86.7 million.

Under the 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, 2007 and 2006, there were no liabilities for any open rate case recorded on the Consolidated Balance Sheets. Currently, neither of the operating subsidiaries is involved in an open general rate case.

Trade and Other Receivables

Trade and other receivables are stated at the 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.

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 Gulf South construction activities. 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. In accordance with SFAS No. 71, the Partnership records AFUDC in connection with Texas Gas construction activities. 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, 2007	2006	2005
Capitalized interest and allowance for borrowed funds used during construction	$ 27.1	$ 2.3	$ 0.7
Allowance for equity funds used during construction	3.0	1.2	1.4

Partner Capital Accounts

For purposes of maintaining the 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 incentive distribution rights.

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 and charge-in-lieu of income taxes on the Consolidated Statements of Income. Note 11 contains more information regarding the Partnership's income taxes.

Reclassifications

Certain reclassifications have been made to the 2006 and 2005 financial statements to conform to the 2007 presentation, primarily related to individual amounts and captions within the Operating Activities section of the Consolidated Statements of Cash Flows.

Note 3: Commitments and Contingencies

Calpine Energy Services (Calpine) Settlement

In 2002 and 2003, Calpine entered into two 20-year transportation agreements with Gulf South. In December 2005, Calpine filed for Chapter 11 Bankruptcy protection and in early 2006 discontinued making payments on one of the transportation agreements. Gulf South continued to invoice Calpine under the transportation agreements and fully reserved the revenues associated with the contract on which Calpine was not making payments. In December 2007, Gulf South and Calpine filed a stipulation and agreement with the Bankruptcy court, which was approved in January 2008, to terminate the firm transportation agreement on which Calpine was delinquent, and to settle all of Gulf South's claims in the Bankruptcy proceedings for approximately $16.5 million. The claim was to be paid in the form of Calpine stock, along with other general creditors having claims in the Bankruptcy proceeding. In January 2008, Boardwalk sold the Bankruptcy claim to a third party and received a cash payment of approximately $15.3 million. The assignment is with recourse subject to the issuance of Calpine stock in the full amount of the claim. As a result of the settlement, in 2007 Boardwalk recognized $4.1 million in Gas transportation revenues related to invoiced amounts past due, which were previously reserved. The remainder of the settlement amount will be recognized upon full payment of the settlement amount by Calpine.

Jackson Storage Gas Loss

The Partnership's Jackson, Mississippi aquifer storage facility has a working gas capacity of approximately 5.0 billion cubic feet (Bcf) and is primarily used for operational purposes. In the fourth quarter 2007, it was determined that, based upon tests used to estimate the amount of gas stored in the facility, gas loss had occurred in the range of 1.3 to 1.7 Bcf. As a result of the estimated gas loss, the Partnership recognized a charge of $0.7 million to Operation and maintenance expense in the fourth quarter 2007. This amount was determined by applying the carrying value of gas in the facility of $0.53 per million British thermal units (MMBtu), to the low end of the range of estimated gas loss of 1.3 Bcf. An assessment is underway to determine whether the gas will need to be replaced in order to operate the facility and support pipeline operations. A more comprehensive test of the field will be performed in the second quarter 2008. If the pending test results indicate that the actual gas loss is greater than the estimated 1.3 Bcf, this could result in a future adjustment to the estimate.

Impact of Hurricanes Katrina and Rita

In August and September 2005, Hurricanes Katrina and Rita (hurricanes), and related storm activity caused extensive and catastrophic physical damage to the offshore, coastal and inland areas in the Gulf Coast region of the United States. A substantial portion of the Partnership's assets are located in the area directly impacted by the hurricanes. The remediation work related to the hurricanes was completed in 2007.

The Partnership reduced its liability for estimated costs associated with the hurricanes by $0.4 million in 2007 and increased the liability by $0.1 million in 2006. The Partnership recorded charges related to the hurricanes of $12.9 million in 2005, $2.0 million of which was recorded to Operating revenues and $10.9 million of which was recorded to Operating costs and expenses. The accrued liability for the hurricanes was zero at December 31, 2007, and $1.0 million at December 31, 2006.

In the third quarter 2007, the Partnership accrued estimated insurance proceeds of $5.1 million for claims related to Hurricane Rita which represented the minimum amount of insurance proceeds that were probable of recovery. This amount resulted in a reduction of Operating Costs and Expenses. In 2006, the Partnership recognized $10.7 million of insurance recoveries associated with Hurricane Katrina, $7.4 million of which was recorded to Operating Costs and Expenses and $3.3 million of which was recorded to Operating Revenues. The Partnership received a cash payment of $6.0 million in the fourth quarter 2006 and the remaining $4.7 million was recorded as a receivable at December 31, 2006. In the first quarter 2007, the Partnership received a final cash payment of $6.2 million of insurance proceeds related to damages incurred during Hurricane Katrina, $4.7 million of which was applied against the receivable and $1.5 million of which was recognized in Gas transportation revenues. Through December 31, 2007, the Partnership has received a total of approximately $12.2 million in insurance proceeds related to Hurricane Katrina, and will continue to pursue additional recovery of insurance proceeds related to Hurricane Rita.

Legal Proceedings

Napoleonville Salt Dome Matter

In December 2003, natural gas leaks were observed near two natural gas storage caverns that were being leased and operated by Gulf South for natural gas storage in Napoleonville, Louisiana. Gulf South commenced remediation efforts immediately and ceased using those storage caverns. Two class action lawsuits were filed relating to this incident and were converted to individual actions. Several individual actions have been filed against Gulf South and other defendants by local residents and businesses. In addition, the lessor of the property has filed an affirmative claim against Gulf South in an action filed against the lessor by one of Gulf South's insurers. Gulf South continues to vigorously defend each of these actions, however it is not possible to predict the outcome of this litigation as the cases remain in discovery. Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. Gulf South has settled many of the cases filed against it and may enter into discussions in an attempt to settle other cases if Gulf South believes it is appropriate to do so.

The remediation work related to the incident was completed in November 2006. Gulf South incurred $8.9 million for remediation costs, root cause investigation, and legal fees. Gulf South has made demand for reimbursement from its insurance carriers and will continue to pursue recoveries of the remaining expenses, including legal expenses. To date the insurance carriers have not taken any definitive coverage positions on all of the issues raised in the various lawsuits. During 2007, Gulf South has received $0.3 million of insurance reimbursements for legal expenses and root cause investigation.

Other Legal Matters

In connection with the acquisition of Texas Gas, 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

East Texas to Mississippi Expansion. On June 18, 2007, the FERC granted the Partnership the authority to construct, own and operate a pipeline expansion consisting of approximately 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression having approximately 1.7 Bcf of new peak-day transmission capacity. Customers have contracted at fixed rates for 1.4 Bcf per day of firm transportation capacity on a long-term basis (with a weighted average term of approximately 6.8 years) from Carthage, Texas, which represents substantially all of the normal operating capacity. The pipeline facilities from Keatchie, Louisiana in DeSoto Parish to interconnects with Texas Gas near Bosco, Louisiana, and Columbia Gulf Transmission pipeline at Delhi, Louisiana began flowing gas on December 31, 2007. The remaining pipeline facilities from Delhi, Louisiana to Harrisville, Mississippi, began flowing gas during January 2008. Currently, the three compressor units at the Carthage compressor station are operational and the Partnership is making all of its primary firm contractual deliveries into the Delhi, Louisiana area and a substantial percentage of its primary firm contractual deliveries to markets in Mississippi. The Partnership is in the process of commissioning the remaining compression facilities associated with this project, which the Partnership expects to be completed during the second quarter 2008.

Gulf Crossing Project. The Partnership is pursuing construction of a new interstate pipeline that will begin near Sherman, Texas and proceed to the Perryville, Louisiana area. The project will be owned by Gulf Crossing, the Partnership's newly formed interstate pipeline subsidiary, and will consist of approximately 357 miles of 42-inch pipeline having up to approximately 1.7 Bcf of peak-day transmission capacity. Additionally, Gulf Crossing has entered into, subject to regulatory approval: (i) an operating lease for up to 1.4 Bcf per day of capacity on the Partnership's Gulf South pipeline system (including capacity on the Southeast Expansion and capacity on a portion of the East Texas to Mississippi Expansion) to make deliveries to an interconnect with Transcontinental Pipe Line Company (Transco) in Choctaw County, Alabama (Transco 85); and (ii) an operating lease with Enogex, a third-party intrastate pipeline, which will bring certain gas supplies to the Partnership's system. Customers have contracted at fixed rates for 1.1 Bcf per day of long-term firm transportation capacity (with a weighted average term of approximately 9.5 years). The certificate application for this project was filed with the FERC on June 19, 2007, and the Partnership expects this project to be in service by the first quarter 2009.

Southeast Expansion. On September 28, 2007, the FERC granted the Partnership the authority to construct, own and operate a pipeline expansion originating near Harrisville, Mississippi and extending to an interconnect with Transco 85. This expansion will initially consist of approximately 112 miles of 42-inch pipeline having approximately 1.2 Bcf of peak-day transmission capacity. To accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above, this project will be expanded to 2.2 Bcf of peak-day transmission capacity. In addition, the FERC approved the Partnership's 260 million cubic feet (MMcf) per day operating lease with Destin Pipeline Company which will provide the Partnership enhanced access to markets in Florida. Customers have contracted at fixed rates for 660 MMcf per day of firm transportation capacity on a long-term basis (with a weighted-average term of 8.7 years), in addition to the capacity leased to Gulf Crossing discussed above. Construction has commenced and the Partnership expects this project to be in service during the second quarter 2008.

Fayetteville and Greenville Laterals. The Partnership is pursuing the construction of two laterals connected to 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 and consist of approximately 165 miles of 36-inch pipeline with an initial design of approximately 0.8 Bcf of peak-day transmission capacity. 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 pipeline with an initial design capacity of approximately 0.8 Bcf of peak-day transmission capacity. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast. Customers have contracted at fixed rates for 575 MMcf per day of initial capacity, with options for additional capacity that, if exercised, could add 325 MMcf per day of capacity. The certificate application for this project was filed with the FERC on July 11, 2007. The Partnership expects the first 60 miles of the Fayetteville Lateral to be in service during the third quarter 2008 and the remainder of the Fayetteville and Greenville Laterals to be in service during the first quarter 2009.

Pipeline Expansion Project Costs and Timing. The total capital expenditures for the pipeline expansion projects through December 31, 2007 were $1.2 billion.

Storage Expansion Projects

Western Kentucky Storage Expansion Phase II. In December 2006, the FERC issued a certificate approving the Phase II storage expansion project which expanded the working gas capacity in the Partnership's western Kentucky storage complex by approximately 9.0 Bcf. This project is supported by binding commitments from customers to contract on a long-term basis (with a weighted-average term of 8.3 years) for the full additional capacity at the Texas Gas maximum applicable rate. The project was placed in service in November 2007.

Western Kentucky Storage Expansion Phase III. The Partnership has signed 10-year precedent agreements for 5.1 Bcf of storage capacity for its Phase III storage project. The certificate application for this project was filed with the FERC on June 25, 2007, seeking approval to develop up to 8.3 Bcf of new storage capacity if Texas Gas is granted market-based rate authority for the new storage capacity being proposed. The cost of this project will be dependent on the ultimate size of the expansion. The Partnership expects 5.4 Bcf of storage capacity to be in service in 2008.

Magnolia Storage Facility. The Partnership was 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, the Partnership will be unable to place the cavern in service as expected. As a result, the Partnership has elected to abandon that cavern and is 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, Accounting for the Impairment or Disposal of Long-Lived Assets, the carrying value of the cavern and related facilities of approximately $45.1 million was tested for recoverability. In the second quarter 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. The Partnership expects 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 it is determined in the future that the assets cannot be used in conjunction with a new cavern, 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.

Pipeline Integrity

The Partnership expenses all costs incurred in the development of its integrity management program, as defined by the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the ongoing inspecting, testing and reporting on the condition of the pipeline system except costs incurred to replace segments of pipeline or install software or equipment which are capitalized to the extent they meet the requirements of the Partnership's capitalization policy for those types of expenditures. As of December 31, 2007, the Partnership has invested approximately $12.3 million to develop and implement integrity management program computer systems that allow it to dynamically assess various pipeline risks on an integrated basis. The Partnership has systematically used smart, in-line inspection tools to verify the integrity of certain of its pipelines.

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 the agencies.

As of December 31, 2007 and 2006, the Partnership had an accrued liability of approximately $17.0 million and $18.4 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 approximately 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, 2007 and 2006, approximately $2.7 million and $3.5 million were recorded in Other current liabilities. As of December 31, 2007 and 2006, approximately $14.3 million and $14.9 million were recorded in Other Liabilities and Deferred Credits.

On October 20, 2006, Texas Gas received notice from the Environmental Protection Agency (EPA) that Texas Gas is a potentially responsible party under the Comprehensive Environmental Response, Compensation, and Liability Act 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.

On November 2, 2005, Texas Gas received notice from the EPA that it has been identified as a de minimis settlement waste contributor at a Mercury Refining Superfund Site located at the Towns of Colonie and Guilderland, Albany County, New York. A de minimis party is one which sent less than 1.0% of the total mercury and/or mercury bearing materials to the site. As a de minimis party, Texas Gas was offered participation in a settlement agreement. The settlement amount for Texas Gas is approximately $0.1 million. The EPA held a 30-day public comment period regarding the settlement, but has not acted on it. In November 2007, Texas Gas received a notice from the EPA that it was withdrawing its settlement offer and would be issuing a new settlement offer in the future. Based upon the EPA's notice it appears that Texas Gas will still be considered a de minimis party, and it is not expected that the new settlement will have a material effect on our financial condition, results of operations or cash flows.

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 Partnership presently operates two facilities in areas affected by non-attainment requirements for the current ozone standard (eight-hour standard). As of December 31, 2007, the Partnership had incurred costs of approximately $13.7 million for emission control modifications of compression equipment located at facilities required to comply with current CAA provisions, the Amendments and state implementation plans for nitrogen oxide reductions. These costs are being recorded as additions to PPE as the modifications are added. 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, however the Partnership is unable at this time to estimate with any certainty the cost of any additions that may be required.

In June 2007, the EPA proposed to lower the 8-hour ozone standard relevant to non-attainment areas. If adopted, new non-attainment areas will likely be identified which may require additional emission controls for compliance at as many as 14 facilities operated by the Partnership. The anticipated effective date for compliance with the proposed standard if adopted in its current state, is between 2013 and 2016.

In addition, the EPA and the State of Texas promulgated new rules regarding hazardous air pollutants which required additional controls or equipment modifications at seven Partnership facilities. The Partnership has substantially complied and has incurred costs of $2.6 million at these facilities.

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.

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. The actual costs incurred will depend on the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA or other governmental authorities and other factors.

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.

Lease Commitments

The Partnership has various operating lease commitments extending through the year 2018 generally covering offices and equipment. Total lease expenses for the years ended December 31, 2007, 2006 and 2005 were approximately $7.3 million, $4.7 million and $4.2 million. The following table summarizes minimum future commitments related to these items at December 31, 2007 (in millions):

2008	$	6.7
2009		5.5
2010		5.3
2011		3.0
2012		3.0
Thereafter		13.2
Total	$	36.7

Commitments for Construction

The Partnership incurred $1.2 billion of capital expenditures in 2007. The Partnership's future capital commitments as of December 31, 2007, for contracts already authorized are expected to approximate the following amounts (in millions):

Less than 1 year	$	834.7
1-3 years		16.4
4-5 years		-
More than 5 years		-
Total	$	851.1

Note 4: Property, Plant and Equipment

On December 31, 2007, the Partnership placed in service a portion of its East Texas to Mississippi expansion project from Keatchie, Louisiana in DeSoto Parish to its interconnects with Texas Gas near Bosco, Louisiana and Columbia Gulf Transmission pipeline at Delhi, Louisiana. As a result, approximately $476.0 million was transferred from construction work in progress to depreciable PPE. The assets will generally be depreciated over a term of 35 years. The remaining pipeline to Harrisville, Mississippi was placed in service during January 2008 and the related compression at one of the three compressor stations went in service in January and February 2008.

In November 2007, the Partnership placed in service Phase II of its Western Kentucky storage expansion project which increased the working gas capacity of its Texas Gas system by 9.0 Bcf, resulting in reclassification of approximately $50.0 million from construction work in progress to depreciable PPE. As a result of the expansion, approximately 4.0 Bcf of base gas was sold in 2007, resulting in a total gain of $22.0 million including gains on the settlement of related derivatives.

In conjunction with a review of its offshore pipeline assets in the South Timbalier Bay area, offshore Louisiana, the Partnership discovered that approximately 6 to 7 miles of offshore pipeline did not have adequate cover. In 2007, the Partnership entered into an agreement to sell for a nominal amount the offshore pipeline assets in their current condition 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 the liability to re-cover the pipeline and other maintenance issues. The total charge for 2007 related to the remediation payment and impairment charge was $9.3 million, $4.8 million of which was recorded to Operation and maintenance expense and the remainder to Asset impairment. The Partnership expects the sale to be completed in 2008.

In 2006, the Partnership received $4.0 million in settlement of a lawsuit concerning the parties' rights and obligations under a lease for a platform being decommissioned in the Eugene Island area in the Gulf of Mexico. The proceeds were used to offset the costs of rebuilding certain offshore facilities. Also, in 2006, the Partnership received $2.5 million for the sale of offshore transmission facilities in the Gulf of Mexico at West Cameron 294. The sale of the facilities was considered a normal retirement. In accordance with the composite method of accounting for PPE, the proceeds and the related book value of the plant were recorded to accumulated depreciation which is classified within PPE, net on the Consolidated Balance Sheets.

The following table presents the Partnership's PPE as of December 31, 2007 and 2006 (in thousands):

Category	2007 Class Amount	Weighted-Average Useful Lives (Years)	2006 Class Amount	Weighted-Average Useful Lives (Years)
Depreciable plant:				
Intangible	$ 24,897	9	$ 18,901	9
Gathering	92,828	19	90,787	19
Storage	198,110	49	163,323	48
Transmission	2,125,864	43	1,601,064	45
General	79,605	15	63,698	16
Total utility depreciable plant	2,521,304	41	1,937,773	43
Non-depreciable:				
Land	9,643		9,386	
Storage	71,182		85,392	
Construction work in progress	951,433		165,916	
Other	14,326		13,381	
Total other	1,046,584		274,075	
Total PPE	3,567,888		2,211,848	
Less: accumulated depreciation	262,477		187,412	
Total PPE, net	$ 3,305,411		$ 2,024,436	

The non-transmission assets have weighted-average useful lives of 33 years and 32 years as of December 31, 2007 and 2006 and depreciable asset values of $395.4 million and $336.7 million as of December 31, 2007 and 2006. 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, particularly the Bistineau storage facility of which the Partnership owns 91.7%, the Mobile Bay Pipeline of which the Partnership owns 50.0%, offshore pipeline assets, onshore pipeline and gathering assets, in each of 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. As of December 31, 2007, the gross investment in PPE related to these assets was $87.5 million, approximately $57.0 million, $12.8 million and $11.2 million of which was due to the Bistineau storage, offshore assets and Mobile Bay Pipeline interests. The accumulated depreciation was $17.4 million, approximately $5.0 million, $10.4 million and $1.0 million of which was due to the Bistineau storage, offshore assets and Mobile Bay Pipeline interests.

Note 5: Asset Retirement Obligations

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 when removed from certain compressor stations and meter station buildings. 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. Abatement of asbestos consists of removal, transportation and disposal. Legal obligations exist for certain other Partnership assets; however, the fair value of the obligations cannot be determined because the end of the system life is potentially indefinite and therefore 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 AROs (in thousands):

	2007	2006
Balance at beginning of year	$ 14,307	$ 14,074
Liabilities recorded	1,529	(366)
Liabilities settled	(499)	-
Accretion expense	722	599
Balance at end of year	$ 16,059	$ 14,307

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 of years between 2112 through 2162. The Partnership believes that the spray-applied asbestos can be maintained, in place, undisturbed, indefinitely, 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.

Depreciation rates for utility plant at Texas Gas, as approved by the FERC are comprised of two components: one based on economic service life (capital recovery) and one based on net costs of removal (negative salvage). Texas Gas accrues and collects in its rates estimated net costs of removal of long-lived assets through negative salvage expense, which does not represent an existing legal obligation. The Partnership has classified $42.4 million and $39.6 million as of December 31, 2007 and 2006, in the accompanying Consolidated Balance Sheets as Provision for other asset retirement.

Note 6: Regulatory Assets and Liabilities

The amounts recorded as regulatory assets and liabilities in the Consolidated Balance Sheets as of December 31, 2007 and 2006, 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 change in Boardwalk Pipelines' tax status. 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. None of the regulatory assets shown below were earning a return as of December 31, 2007 and 2006 (in thousands):

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	2007	2006
Regulatory Assets:		
Pension	$ 9,490	$ 7,820
Tax effect of AFUDC equity	6,381	6,794
Unamortized debt expense and premium on reacquired debt	10,705	11,703
Postretirement benefits other than pension	5,414	10,569
Fuel tracker	943	5,783
Imbalances/storage valuation tracker	-	37
Total regulatory assets	$ 32,933	$ 42,706
Regulatory Liabilities:		
System management/cashout tracker	$ 242	-
Provision for asset retirement	42,380	$ 39,644
Unamortized discount on long-term debt	(1,677)	(1,851)
Postretirement benefits other than pension	12,448	-
Total regulatory liabilities	$ 53,393	$ 37,793

Note 7: Financing

Offerings of Common Units

In addition to its IPO in November 2005, the Partnership has completed three follow-on public equity offerings. The proceeds of the follow-on offerings have been and will be used to finance the Partnership's expansion activities discussed in Note 3. In addition to funds received from the public, the general partner has concurrently contributed amounts to maintain its 2.0% interest in the Partnership. The following table shows the key information related to the follow-on public equity offerings (in millions, except the offering price):

Month of Offering	Number of Common Units	Offering 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
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

The Partnership completed its IPO in November 2005, resulting in net proceeds of approximately $271.4 million. After the IPO, the Partnership had 68.3 million common units issued and outstanding, of which 15.0 million were held by the public. In connection with the IPO, the Partnership and its affiliates effected a number of transactions, including among others:

- the distribution by Boardwalk Pipelines of $126.4 million of cash, receivables and other working capital assets to BPHC;
- the contribution, directly and indirectly, by BPHC of all the equity interests of Boardwalk Pipelines to the Partnership;
- the Partnership's reimbursement to BPHC for $42.1 million of capital expenditures it incurred in connection with the acquisition of Gulf South;

- the assumption by the Partnership of $250.0 million of indebtedness to Loews from BPHC;
- the issuance by the Partnership of limited partner interest in the Partnership to BPHC; and
- the issuance by the Partnership of a 2.0% general partner interest and all of its incentive distribution rights to Boardwalk GP.

Senior Unsecured Debt

On August 17, 2007, the Partnership received net proceeds of approximately $495.3 million after deducting initial purchaser discounts and offering expenses of $4.7 million from the sale of $225.0 million of 5.75% senior unsecured notes of Gulf South due August 15, 2012, and $275.0 million of 6.30% senior unsecured notes of Gulf South due August 15, 2017. Interest on the notes will be payable on February 15 and August 15 of each year, beginning on February 15, 2008.

On November 21, 2006, Boardwalk Pipelines received net proceeds of approximately $248.3 million after deducting underwriting discounts and commissions and offering expenses of $1.7 million from its offering of $250.0 million of 5.88% senior unsecured notes, which are guaranteed by the Partnership. Interest on the notes will be payable on May 15 and November 15 of each year, beginning on May 15, 2007. The notes will mature on November 15, 2016.

The Gulf South and Boardwalk Pipelines notes are redeemable, in whole or in part, at the Partnership's option at any time, at a redemption price equal to the greater of 100.0% 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 Treasury rate plus 20 basis points in the case of the 2012 Gulf South notes and 2016 Boardwalk Pipelines notes, or 25 basis points in the case of the 2017 Gulf South notes, plus accrued and unpaid interest, if any. Other customary covenants apply, including those concerning events of default.

The following table represents all long-term debt issues outstanding (in thousands):

	December 31, 2007	December 31, 2006
Boardwalk Pipelines		
5.88% Notes due 2016	$ 250,000	$ 250,000
5.20% Notes due 2018	185,000	185,000
5.50% Notes due 2017	300,000	300,000
Gulf South		
6.30% Notes due 2017	275,000	-
5.75% Notes due 2012	225,000	-
5.05% Notes due 2015	275,000	275,000
Texas Gas		
7.25% Debentures due 2027	100,000	100,000
4.60% Notes due 2015	250,000	250,000
	1,860,000	1,360,000
Unamortized debt discount	(12,086)	(9,080)
Total long-term debt	$ 1,847,914	$ 1,350,920

As of December 31, 2007 and 2006, the weighted-average interest rate of the Partnership's long-term debt was 5.82% and 5.40%.

The long-term debt has 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. The Partnership relies on distributions and advances from the operating subsidiaries to fulfill its debt obligations. All debt obligations are unsecured. At December 31, 2007, Boardwalk Pipelines and the operating subsidiaries were in compliance with their debt covenants.

Revolving Credit Facility

The Partnership maintains a $1.0 billion revolving credit facility, which was increased from $700.0 million in November 2007, under which Boardwalk Pipelines, Gulf South and Texas Gas each may borrow funds, up to applicable sub-limits. Interest on amounts drawn under the credit facility is payable at a floating rate equal to an applicable spread per annum over LIBOR or a base rate defined as the greater of the prime rate or the Federal funds rate plus 50 basis points. Under the terms of the agreement, each of the borrowers must maintain a minimum ratio, as of the last day of each fiscal quarter, of consolidated total debt to consolidated earnings before interest, income taxes and depreciation and amortization (as defined in the agreement), measured for the preceding twelve months, of not more than five to one. The revolving credit facility has a maturity date of June 29, 2012.

As of December 31, 2007, no funds were drawn under the facility, however, the Partnership had outstanding letters of credit under the facility for $185.6 million to support certain obligations associated with the Fayetteville and Greenville Lateral and Gulf Crossing expansion projects which reduced the available capacity under the facility by such amount. As of December 31, 2007, the Partnership was in compliance with all the covenant requirements under the credit agreement. During 2006, the Partnership had borrowed and repaid $90.0 million under this credit facility. The interest rates on the borrowings were 5.55% to 5.73%.

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.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At December 31, 2007 and December 31, 2006, approximately $16.3 million and $14.0 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.

As a result of the approval of Phase II of the Western Kentucky storage expansion project, approximately 4.8 Bcf of gas stored underground with a book value of $11.3 million became available for sale, although it was subsequently determined that 0.8 Bcf of the gas would be used for line pack for the Partnership's Fayetteville and Greenville Lateral expansion project. The Partnership entered into derivatives to hedge the price exposure related to 3.0 Bcf of the storage gas sold under forward sales agreements, which were designated as cash flow hedges during February 2007, concurrent with the designation of the forward sales agreements as normal sales. The derivatives were settled in March 2007, when the sales price was determined. The Partnership entered into derivatives related to the remaining 1.0 Bcf of storage gas available for sale which were not designated as cash flow hedges and have been marked to fair value through earnings. In the third and fourth quarters 2007, all of the storage gas available for sale was sold and the related derivatives were settled resulting in a gain of $22.0 million. The gain was included in Net gain on disposal of operating assets and related contracts on the Consolidated Statements of Income.

In the second quarter 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 the Partnership's Gulf Crossing and Southeast Expansion projects, approximately 1.3 Bcf of which remained outstanding at December 31, 2007. The derivatives were not designated as hedges and were marked to fair value through earnings resulting in a loss of $1.0 million for the year ended December 31, 2007.

In August 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 reference rate on the rate lock was 4.74%. Under the terms of the rate lock, the counterparty would pay the Partnership a settlement amount if the 10-year Treasury rate is greater than the reference rate on February 1, 2008. Conversely, the Partnership would pay the counterparty a settlement amount if the 10-year Treasury rate is less than the reference rate. 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 income for the fair value of the rate lock. On February 1, 2008, the Partnership paid the counterparty approximately $15.0 million to settle the rate lock. The effective portion of the loss will be recognized in Interest expense over the term of the related debt to be issued.

In August 2006, the Partnership entered into Treasury rate locks with two counterparties each for a notional amount of $100.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through August 1, 2007. The reference rates on the rate locks were 5.00% and 4.96%. The rate locks were designated as cash flow hedges in accordance with SFAS No. 133. In August 2007, the rate locks were settled resulting in payments to the counterparties of approximately $3.9 million. The effective amount of the hedge, of approximately $3.4 million is being amortized to interest expense over the 10-year term of the related notes which were issued in August 2007.

With the exception of the derivatives related to storage gas volumes and line pack gas purchases referred to above, the derivatives related to the sale or purchase of natural gas, cash for fuel reimbursement and debt issuance 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 contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive income. The deferred gains and losses are recognized in the Consolidated Statements of Income when the anticipated transactions affect earnings. 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 project, 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 fair values of derivatives existing as of December 31, 2007 and 2006, were included in the following captions in the Consolidated Balance Sheets (in millions):

	December 31, 2007	December 31, 2006
Prepaid expenses and other current assets	$ 2.2	$ 13.7
Other current liabilities	9.4	5.1
Accumulated other comprehensive (loss) income	(8.9)	8.3

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. 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. No ineffectiveness was recorded during 2005. The Partnership did not discontinue any cash flow hedges during the years ended December 31, 2007 and 2006.

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Note 9: 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 will be 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. During 2006, the Partnership funded approximately $18.0 million to the Texas Gas retirement plan including approximately $11.4 million of additional funding that the Partnership elected to provide to immediately improve the funded status of the plan. Due to the additional funding, the Partnership was not required to fund any amount to the Texas Gas retirement plan in 2007 and does not expect to fund any amount in 2008. Through December 31, 2007, 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 Pensions (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 $0.9 million, $0.3 million and $3.9 million to the plan in 2007, 2006 and 2005. 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 2008.

In May 2006, as part of an overall cost reduction program, Texas Gas announced to its employees and retirees a plan to make changes to its postretirement benefits plan beginning January 1, 2007. Under the amended plan, Texas Gas will cap its contributions toward medical benefit coverage for retirees younger than age 65 to the amount contributed for each retiree in 2006. For retirees age 65 and older, Texas Gas will cap its contribution at three times the 2006 amount. In addition, Texas Gas will no longer cover prescription drug costs for retirees age 65 and older. The changes resulted in an estimated reduction in the accumulated postretirement benefit obligation (APBO) of approximately $75.3 million. For the year ended December 31, 2006, the change resulted in a reduction to net periodic benefit cost of $9.0 million from the amount that would otherwise have been recognized.

Due to the Texas Gas rate case settlement in the first quarter 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. Texas Gas is precluded from seeking future recovery of additional amounts for PBOP costs.

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 would provide 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, 2007 and 2006, were as follows (in thousands):

	Retirement Plans For the Year Ended December 31,		PBOP For the Year Ended December 31,	
	2007	2006	2007	2006
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 136,886	$ 116,931	$ 65,341	$ 134,188
Service cost	3,929	4,432	608	1,319
Interest cost	6,599	6,695	3,274	5,147
Plan participants' contributions	-	-	828	1,509
Actuarial (gain) loss	(2,197)	6,326	(9,343)	4,902
Benefits paid	(575)	(3,576)	(4,083)	(7,633)
Retirement / PBOP plan amendment	3	73	-	(75,271)
Settlement	(36,141)	-	-	-
Special termination benefits (ERIP)	-	6,005	-	884
Retiree drug subsidy	-	-	309	296
Benefit obligation at end of period	$ 108,504	$ 136,886	$ 56,934	$ 65,341
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 121,125	$ 96,193	$ 80,218	$ 79,462
Actual return on plan assets	6,489	10,468	6,381	6,539
Benefits paid	(575)	(3,576)	(4,082)	(7,633)
Company contributions	395	18,040	883	341
Plan participants' contributions	-	-	828	1,509
Settlement	(36,141)	-	-	-
Fair value of plan assets at end of period	$ 91,293	$ 121,125	$ 84,228	$ 80,218
Funded status	$ (17,211)	$ (15,761)	$ 27,294	$ 14,877
Items not yet recognized as components of net periodic cost:				
Prior service cost	$ 71	$ 73	$ (62,984)	$ (70,744)

Net actuarial loss	11,731	17,967	10,658	22,316
Total	$ 11,802	$ 18,040	$ (52,326)	$ (48,428)

The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2008. At December 31, 2007 and 2006, the following aggregate information relates only to the underfunded retirement plan (in thousands):

	For the Year Ended December 31, 2007	2006
Projected benefit obligation	$ 108,504	$ 136,886
Accumulated benefit obligation	94,590	118,147
Fair value of plan assets	91,293	121,125

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, 2007, 2006 and 2005 were the following (in thousands):

	Retirement Plans For the Year Ended December 31,			PBOP For the Year Ended December 31,		
	2007	2006	2005	2007	2006	2005
Service cost	$ 3,929	$ 4,432	$ 4,067	$ 608	$ 1,319	$ 2,076
Interest cost	6,599	6,695	6,283	3,274	5,147	7,222
Expected return on plan assets	(7,146)	(7,131)	(6,859)	(4,734)	(4,653)	(4,632)
Amortization of prior service credit	5	-	-	(7,760)	(4,527)	-
Amortization of unrecognized net loss	242	713	300	668	1,112	362
Settlement charge	4,454	-	-	-	-	-
Special termination benefit (ERIP)	-	6,005	-	-	884	-
Regulatory asset (increase) decrease	(1,669)	(3,979)	(3,713)	5,415	7,337	-
Net periodic pension expense	$ 6,414	$ 6,735	$ 78	$ (2,529)	$ 6,619	$ 5,028

The decrease in the regulatory asset for PBOP was due primarily to the amortization of costs incurred in prior years. 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 thousands):

	Retirement Plans	PBOP
2008	$ 3,397	$ 4,693
2009	3,633	4,499
2010	5,783	4,294

2011	7,140	4,282
2012	9,391	4,116
2013-2017	67,556	19,997

Weighted –Average Assumptions

The Partnership's weighted-average asset allocations at December 31, 2007 and 2006, for both the qualified retirement plan and PBOP trusts by category were as follows:

	Retirement Plans		PBOP	
	December 31, 2007	December 31, 2006	December 31, 2007	December 31, 2006
Debt securities	45.5%	49.1%	40.4%	46.6%
Equity securities	22.7%	27.1%	22.1%	29.2%
Limited partnerships	13.3%	9.3%	25.2%	23.6%
Comingled funds	12.5%	9.4%	-	-
Cash, short-term investments and other	6.0%	5.1%	12.3%	0.6%
Total	100.0%	100.0%	100.0%	100.0%

The Partnership employs a total-return approach whereby a mix of equities and fixed income investments is used to maximize the long-term return of 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 Partnership's goal for 2007 was to allocate between 30.0% and 50.0% 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/liability studies and quarterly investment portfolio reviews.

Weighted-average assumptions used to determine benefit obligations for the years ended December 31, 2007 and 2006 were the following:

	Retirement Plans For the Year Ended December 31,		PBOP For the Year Ended December 31,	
	2007	2006	2007	2006
Discount rate	6.00%	5.75%	6.00%	5.75%
Rate of compensation increase	4.00%	5.50%	-	-

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

	Retirement Plans For the Year Ended December 31,			PBOP For the Year Ended December 31,		
	2007	2006	2005	2007	2006	2005
Discount rate	5.94%	5.63%	5.88%	5.75%	5.63% to 5.75%	5.88%
	7.50%	7.50%	7.50%	5.00%	5.00%	5.00%

Expected return on plan assets				to 6.15%	to 6.15%	to 6.15%
Rate of compensation increase	5.50%	5.50%	5.50%	-	-	-

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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 health care-cost-trend rates would have had the following effects on amounts reported for the year ended December 31, 2007 (in thousands):

	2007
Effect of 1% Increase:	
Benefit obligation at end of year	$ 1,212
Total of service and interest costs for year	81
Effect of 1% Decrease:	
Benefit obligation at end of year	$ (1,481)
Total of service and interest costs for year	(102)

For measurement purposes, at December 31, 2007, health care costs for the plans were assumed to increase 9.0% for 2008-2009 grading down to 5.0% in 0.5% annual increments for participants not eligible for Medicare and 10.0% grading down to 5.0% in 0.5% annual increments for participants eligible for Medicare. For December 31, 2006, measurement purposes, health care costs for the plans were assumed to increase 9.0% for 2007-2008, grading down to 5.0% in 0.5% annual increments for participants not eligible for Medicare and 10.5% grading down to 5.0% 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 $5.3 million, $5.1 million and $3.9 million for the years ended December 31, 2007, 2006 and 2005.

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, 2007 and 2006, and changes during the years ended December 31, 2007 and 2006, is presented below:

	Phantom GP Units	Total Fair Value (in thousands)	Weighted-Average Vesting Period (in years)
Granted 7/15/2006 (a)	125	$ 3,398	3.5
Granted 12/20/2006 (a)	125	6,250	4.0

Outstanding @ 12/31/2006 (b)	250	12,500	3.5
Granted (a)	116	5,800	4.0
Forfeited	(5)	-	-
Outstanding @ 12/31/2007 (b)	361	18,050	3.0

(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 $3.3 million and $0.8 million in Administrative and general expenses during 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, 2007, of $13.9 million will be recognized over the average remaining vesting period of approximately 3.0 years. Approximately 139 Phantom GP Units were available for grant under the plan at December 31, 2007.

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 has 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 50.0% on the second anniversary of the grant date and 50.0% 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 and unit appreciation rights under the plan.

A summary of the status of the Partnership’s LTIP as of December 31, 2007, 2006 and 2005, and changes during the years ended December 31, 2007 and 2006, is presented below:

	Phantom Common Units	Total Fair Value (in thousands)	Weighted-Average Vesting Period (in years)
Outstanding @ 12/31/2005 (a)	29,177	$ 525	2.3
Granted (b)	49,387	1,537	2.5
Forfeited	(3,479)	-	-
Outstanding @ 12/31/2006 (a)	75,085	2,413	2.2
Granted (b)	49,966	1,530	2.5
Vested (c)	(14,431)	-	-
Forfeited	(2,099)	-	-
Outstanding @ 12/31/2007 (a)	108,521	3,493	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.

(c) Represents cash paid for vested awards.

The fair value of the awards at the date of grant was based on the formula contained in the LTIP. 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 and $0.4 million in Administrative and general expenses during 2007 and 2006 for the ratable recognition of the Phantom Common Unit awards fair value. Amounts recognized in 2005 were immaterial. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2007, of $2.0 million will be recognized over the average remaining vesting period of approximately 1.8 years.

On February 27, 2007, the general partner purchased 1,500 of the Partnership's common units in the open market at a price of $36.61 per unit and on March 23, 2006, the general partner purchased 1,000 common units in the open market at a price of $21.38 per unit. These units were granted under the LTIP to the independent directors as part of their director compensation. At December 31, 2007, 3,522,500 units were available for grants under LTIP.

Note 10: 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 contractual participation rights which are incentive distribution rights (IDRs) in accordance with the partnership agreement as follows:

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Common and Subordinated Unitholders	General Partner
Minimum Quarterly Distribution	$0.3500	98.0%	2.0%
First Target Distribution	up to $0.4025	98.0%	2.0%
Second Target Distribution	above $0.4025 up to $0.4375	85.0%	15.0%
Third Target Distribution	above $0.4375 up to $0.5250	75.0%	25.0%
Thereafter	above $0.5250	50.0%	50.0%

The amounts reported for net income per limited partner unit on the Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005, were adjusted to take into account an assumed allocation to the general partner's incentive distribution rights. Payments made on account of the incentive distribution rights 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 thousands, except weighted average units and per unit data):

	For the Year Ended December 31,		For the Period November 15, 2005 through December 31,
	2007	2006	2005
Limited partners' interest in net income	$ 220,726	$ 193,599	$ 35,272
Less assumed allocation to incentive distribution rights	4,323	5,187	-
Net income available to limited partners	216,403	188,412	35,272
Less assumed allocation to subordinated units	61,949	61,087	11,382
Net income available to common units	$ 154,454	$ 127,325	$ 23,890
Weighted average common units	82,510,917	68,977,766	68,256,122

Weighted average subordinated units	33,093,878	33,093,878	33,093,878
Net income per limited partner unit – common and subordinated units	$ 1.87	$ 1.85	$ 0.35

The Partnership has declared quarterly distributions per unit to unitholders of record, including common and subordinated units and the 2.0% general partner interest and IDRs held by its general partner as follows (in thousands, except distribution per unit):

Payable Date	Distribution per Unit	Amount Paid to Common and Subordinated Unitholders	Amount Paid to General Partner (Including IDRs)
February 25, 2008	$ 0.46	$ 56,925	$ 2,709
November 12, 2007	0.45	52,313	2,158
August 13, 2007	0.44	51,150	1,770
May 14, 2007	0.43	49,988	1,519
February 27, 2007	0.415	44,924	1,128
November 6, 2006	0.40	40,540	827
August 18, 2006	0.38	38,513	786
May 19, 2006	0.36	36,486	745
February 23, 2006	0.179*	18,121	370

*Distribution represented a prorated portion of the $0.35 per unit "minimum quarterly distribution" (as defined in the Partnership's partnership agreement) for the period November 15, 2005 through December 31, 2005.

Note 11: Income Tax

Results of operations for the year ended December 31, 2005, reflect a change in the tax status associated with the Partnership and Boardwalk Pipelines, coincident with the IPO. Accordingly, the Partnership recorded a charge-in-lieu of income taxes for the period January 1, 2005, through the date of the offering. Pursuant to the change in tax status, the Partnership also eliminated its balance of accumulated deferred income taxes at the date of the offering. The subsidiaries of the Partnership directly incur some income-based state taxes which are accrued as Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

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. The Partnership's tax years 2005 through 2007 remain subject to examination by the Internal Revenue Service (IRS) and the states in which it operates.

Following is a summary of the provision for Income taxes and charge-in-lieu of income taxes for the periods ended December 31, 2007, 2006 and 2005 (in thousands):

	For the Year Ended December 31,		
	2007	2006	2005
Current expense:			
Federal	-	-	$ 4,044
State	$ 787	$ 292	870
Total	787	292	4,914
Deferred provision (benefit):			
Federal	-	-	36,690
State	(18)	(39)	7,890
Elimination of cumulative deferred taxes	-	-	10,102
Total	(18)	(39)	54,682
Income taxes and charge-in-lieu of income taxes	$ 769	$ 253	$ 59,596

Reconciliations from the provision at the statutory rate to the Income tax and charge-in-lieu of income taxes provision are as follows (in thousands):

	For the Year Ended December 31,		
	2007	2006	2005
Provision at statutory rate	-	-	$ 43,583
Increases in taxes resulting from:			
State income taxes	$ 769	$ 253	5,694
Other, net	-	-	217
Elimination of deferred taxes	-	-	10,102
Income taxes and charge-in-lieu of income taxes	$ 769	$ 253	$ 59,596

As of December 31, 2007 and 2006, there were no significant deferred income tax assets or liabilities.

Note 12: 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.

Advances to Affiliates: Advances to affiliates, which are represented by demand notes, earn a variable rate of interest, which is adjusted regularly to reflect current market conditions. Therefore, the carrying amount is a reasonable estimate of fair value. The interest rate on intercompany demand notes is LIBOR plus one percent and is adjusted every three months.

Long-Term Debt: All long-term debt is publicly traded, except for debt held by Gulf South. Estimated fair value is based on quoted market prices and market prices of similar debt, for debt held by Gulf South, at December 31, 2007 and 2006.

The carrying amount and estimated fair values of the Partnership's financial instruments as of December 31, 2007 and 2006 were as follows (in thousands):

	2007		2006	
Financial Assets	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 317,319	$ 317,319	$ 399,032	$ 399,032
Financial Liabilities				
Long-term debt	$ 1,847,914	$ 1,834,161	$ 1,350,920	$ 1,318,293

Note 13: Accumulated Other Comprehensive Income (Loss)

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

	For the Year Ended December 31, 2007	2006
(Loss) gain on cash flow hedges, net of tax	$ (8,891)	$ 8,309
Deferred components of net periodic benefit cost, net of tax	13,103	14,803
Total Accumulated other comprehensive income, net of tax	$ 4,212	$ 23,112

In 2008, the Partnership will recognize $8.7 million of the amounts shown above in earnings. This amount is comprised of increases to earnings of $1.2 million related to cash flow hedges and $7.5 million related to net periodic benefit cost.

Note 14: Major Customers and Transactions with Affiliates

Major Customers

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

	For the Year Ended December 31,					
	2007		2006		2005	
Customer	Revenue	%	Revenue	%	Revenue	%
Atmos Energy	$ 63,900	10.0%	$ 56,413	9.3%	$ 61,774	11.0%

Natural gas price volatility has increased dramatically in recent years, which has materially increased credit risk related to gas loaned to customers. As of December 31, 2007, the amount of gas loaned by the operating subsidiaries was approximately 12.7 TBtu and, assuming an average market price during December 2007 of $7.13 per MMBtu, the market value of that gas was approximately $90.6 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.

Transactions with Affiliates

Loews provides a variety of corporate services to the Partnership and its subsidiaries under services agreements. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged $12.1 million, $13.0 million, and $9.7 million for the years ended December 31, 2007, 2006 and 2005 to the Partnership based on the actual time spent by Loews personnel performing these services, plus related expenses.

Distributions paid related to common and subordinated units held by BPHC, 2.0% general partner interest and IDRs held by Boardwalk GP were $156.4 million during 2007 and $116.6 million during 2006.

The Partnership pays franchise and certain other taxes on behalf of BPHC and records a note receivable from BPHC for the amounts paid, which is settled quarterly. The notes accrue interest at LIBOR plus one percent. In 2007 and 2006, the Partnership paid $3.4 million and $0.8 million on behalf of BPHC. A note receivable of $1.6 million remained at December 31, 2007.

Note 15: Recently Issued Accounting Pronouncements

SFAS No. 157, Fair Value Measurements

On September 15, 2006, the FASB issued SFAS No. 157, Fair Value Measurements. Fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. The standard clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, the standard establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity's own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The Statement is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The Partnership is currently evaluating the impact, if any, that SFAS No. 157 would have on its financial statements.

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

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities- including an amendment of SFAS No. 115. SFAS No. 159 allows companies to elect to measure financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option has been chosen are reported in earnings. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. The effective date for the Partnership is January 1, 2008. The Partnership is currently evaluating the impact, if any, of adopting SFAS No. 159 on its financial statements.

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

	For the Year Ended December 31,		
	2007	2006	2005
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 46,106	$ 58,111	$ 45,357

Income taxes, net	340	215	-
Non-cash capital contribution	-	-	681,809
Non-cash dividends	-	-	101,401

Note 17: Selected Quarterly Financial Data (Unaudited)

The Partnership's operating income may vary by quarter. Based on the current rate structure, the operating subsidiaries experience higher income in the first and fourth quarters as compared to the second and third quarters. The following tables summarize selected quarterly financial data for 2007 and 2006 for the Partnership (in thousands, except for earnings per unit):

	2007 For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 169,882	$ 134,732	$ 150,542	$ 188,112
Operating expenses	89,048	86,185	106,236	95,766
Operating income	80,834	48,547	44,306	92,346
Interest expense, net	9,704	9,003	8,567	12,216
Other (income) expense	(1,232)	(575)	159	(334)
Income before income taxes	72,362	40,119	35,580	80,464
Income taxes	267	140	132	230
Net income	$ 72,095	$ 39,979	$ 35,448	$ 80,234
Earnings per unit:				
Common units	$ 0.56	$ 0.35	$ 0.35	$ 0.61
Subordinated units	$ 0.56	$ 0.30	$ 0.17	$ 0.61

	2006 For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 171,489	$ 133,045	$ 128,662	$ 174,446
Operating expenses	92,811	88,272	82,798	89,813
Operating income	78,678	44,773	45,864	84,633
Interest expense, net	13,882	14,414	14,510	15,088
Other income	(366)	(406)	(792)	(185)
Income before income taxes	65,162	30,765	32,146	69,730
Income taxes	(111)	118	246	-
Net income	$ 65,273	$ 30,647	$ 31,900	$ 69,730
Earnings per unit:				
Common units	$ 0.57	$ 0.35	$ 0.35	$ 0.58
Subordinated units	$ 0.57	$ 0.19	$ 0.22	$ 0.58

Note 18: Disposition of Coal Reserves

The Partnership has begun efforts to sell its investment in certain coal reserves along the Ohio River in northern Kentucky and southern Indiana that were originally acquired in the 1970's. A data room has been made available to prospective buyers. The book value of the assets at December 31, 2007 and 2006 was zero. The Partnership expects to complete a sale of the assets in 2008.

Note 19: Guarantee of Securities of Subsidiaries

The Partnership has no independent assets or operations other than its investment in its subsidiaries. The Partnership's operating subsidiaries have issued securities which have all been fully and unconditionally guaranteed by the Partnership. 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 and have no restricted assets at December 31, 2007. See Note 7 for additional information.

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We maintain a system of disclosure controls and procedures which is designed to ensure that information required to be disclosed by us in reports that we file or submit under the federal securities laws, including this report is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by us under the federal securities laws is accumulated and communicated to us on a timely basis to allow decisions regarding required disclosure.

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, 2007.

Changes in Internal Control over Financial Reporting

There were no other changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2007, 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, 2007. 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, 2007, 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.

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:

Name	Age	Position
Rolf A. Gafvert	54	Chief Executive Officer, President and Director
Jamie L. Buskill	43	Chief Financial Officer, Senior Vice-President and Treasurer
Brian A. Cody	50	Senior Vice President of Marketing and Chief Commercial Officer
John C. Earley Jr.	45	Senior Vice President of Operations
Michael E. McMahon	52	Senior Vice President and General Counsel, Secretary
Arthur L. Rebell	67	Director, Chairman of the Board
William R. Cordes	59	Director
Thomas E. Hyland	62	Director
Jonathan E. Nathanson	46	Director
Mark L. Shapiro	63	Director
Andrew H. Tisch	58	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 to February 2007 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 of BGL since its inception in 2005. Mr. Buskill is also the Vice President, Chief Financial Officer and Treasurer of Texas Gas. Mr. Buskill has been employed by Texas Gas in that capacity since Texas Gas was acquired by Boardwalk Pipelines in May 2003. Prior thereto he served in various management roles for Texas Gas and its affiliates since 1986, including Assistant Treasurer and Financial Reporting Manager from 1998 until May 2003.

Brian A. Cody— Mr. Cody has 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.

John C. Earley Jr. —Mr. Earley has been the Senior Vice President of Operations of BGL since March 2007. Prior thereto he had been Senior Vice President of Operations for Gulf South since 2001. Mr. Earley has held various senior leadership roles prior to 2001 and has been employed by Gulf South or it predecessors since 1995.

Michael E. McMahon—Mr. McMahon has been the Senior Vice President and General Counsel 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. 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.

Thomas E. Hyland—Mr. Hyland was a partner in the global accounting firm of PricewaterhouseCoopers, LLP from 1980 until his retirement in July 2005.

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.

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.

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.

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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 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, chief financial officer, principal accounting officer, and all of the directors, officers and employees of our subsidiaries. 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 10.0% 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 2007, in a timely manner, other than one late Form 3 filing for each of Messrs. Cody, Earley and McMahon and one late Form 4 filing for H. Dean Jones II and each of Messrs. Buskill, Cody, Cordes, Earley, Gafvert, Hyland, McMahon and Shapiro.

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 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, improve retention of our executives and appropriately reward their performance both in the long and short term. In doing so, we may consider the executive compensation programs of other companies engaged in similar businesses to ours and 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.

As discussed elsewhere in this Report, our Board does not maintain a Compensation Committee. Therefore, the compensation for Rolf Gafvert our Chief Executive Officer (CEO), Jamie L. Buskill our Chief Financial Officer (CFO) and our three other most highly compensated executive officers (together with our former President, H. Dean Jones II, who has resigned as an officer and director in conjunction with his announced retirement that will be effective March 1, 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 discussions with respect to his own compensation. Named Executive Officers are those officers whose compensation is required to be reported in accordance with Item 402, Executive Compensation, of SEC Regulation S-K rules.

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 LTIP;
- annual grants of phantom general partner units (Phantom GP Units) under our SLTIP; and
- retirement, medical and related benefits.

In establishing the aggregate amount of compensation for our Named Executive Officers for a given year, we do not rely on formula-driven plans which could result in unreasonably high compensation levels. Instead, the primary factor in setting compensation is an evaluation of the individual's performance in the context of our overall performance for such year, particularly the individual's contribution to our financial performance during the year, as well as the compensation paid to the individual in prior years. In light of the shortage of excellent management talent in our industry and our desire to retain our key executives, we may also review and consider compensation levels and types in other companies that are engaged in similar businesses to maintain an understanding of the market for executive talent. Based on these factors, we determine an overall level of compensation.

Base Salary

Our executive compensation policies have emphasized the incentive-based compensation elements discussed below. As a result, the base salaries of our executive officers generally have remained unchanged through the end of 2007, with modest adjustments made from year to year based on merit or other factors. Each year we review the overall mix of compensation to determine if we need to vary any one item of an executive's compensation package.

Incentive Compensation – Cash Bonuses and Phantom Common Unit Awards

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 executives to consider long-term results for our unitholders and providing them with appropriate current cash compensation, we have targeted these compensation elements as approximately three-fourths cash bonus and one-fourth as an award of Phantom Common Units for our most senior executives.

Prior to the beginning of a year, the CEO proposes to the Board bonus targets including cash and equity components for the Partnership as a whole, based on meeting specific financial measures, operating goals and project milestones. At the end of the year, the CEO makes recommendations to the Board regarding amounts to pay both Named Executive Officers and other employees based on whether targets for the year were met and based upon the Named Executive Officers' individual performance and contributions to the Company. The CEO's compensation is determined by the Board based upon a similar appraisal of performance and contributions.

Since we are a limited partnership and our Named Executive Officers are employed by our operating subsidiaries, the executives would incur significant adverse individual tax consequences if they would own our units directly; for example by being taxed as a partner rather than as an employee. Furthermore, the ownership of units by our executives would negatively impact the tax status of our benefit plans. As a result, we have chosen to award our executives equity-based compensation in the form of Phantom Common Units, the economic value of which is directly tied to the value of our common units, but which 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 and 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 that 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 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 50.0% on the second anniversary of the grant date and 50.0% 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. It also promotes retention because the awards would be forfeited if an employee were to resign prior to the vesting date.

We exceeded our financial and operational goals for 2007 and increased our distributions to unitholders in each quarter. As a result, we awarded the full amount of incentive compensation we had targeted for 2007 to our key employees including the Named Executive Officers, of which approximately 75.0% was paid as annual cash bonuses and 25.0% was awarded as Phantom Common Units. In making these awards, our Board considered the factors discussed above, with particular emphasis on the contributions made by the individual executives in 2007 to the success of the expansion projects we have undertaken which are described elsewhere in this Report, among other strategic goals and objectives.

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. Since the value of these awards is directly linked to our performance and the value of our common units and of our general partner, they further align the interests of our Named Executive Officers with those of our unitholders.

We awarded an aggregate of 116 Phantom GP Units in December 2007, which vest in 4.0 years, to 21 of our key employees, of which 65 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 6.0% 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, 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 other 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, nor 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.

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 of Directors 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 2007 or 2006.

Summary of Executive Compensation

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

Summary Compensation Table

Name and Position	Year	Salary	Bonus (1)	Stock Awards (2)	Option Awards	Non-Equity Incentive Plan Compensation (3)	Change in Pension value and nonqualified deferred compensation earnings	All Other Compensation	Total
Rolf A. Gafvert: CEO (PEO)	2007	$ 323,365	$ 300,000	$ 175,253	-	$ 682,664	-	$ 35,360(4)	$ 1,516,642
	2006	240,000	300,000	112,944	-	183,442	-	32,149(4)	868,535
H. Dean Jones II: (10)									
	2007	326,534	275,000	80,013	-	401,786	$ 177,404(5)	31,099(5)	1,291,836
	2006	325,000	195,000	59,778	-	110,065	154,458(5)	24,432(5)	868,733
Jamie L. Buskill: CFO (PFO)	2007	225,000	225,000	36,092	-	302,679	46,602(6)	14,386(6)	849,759
	2006	225,000	100,000	26,196	-	87,011	40,333(6)	14,292(6)	492,832
Brian A. Cody: SVPM	2007	228,846	175,000	59,288	-	364,137	-	23,107(7)	850,378
John C. Earley Jr.: SVPO	2007	226,154	175,000	73,447	-	326,116	-	23,681(8)	824,398
Michael E. McMahon: SVPGC	2007	216,346	125,000	59,288	-	297,545	-	28,938(9)	727,117

(1)

Reflects cash amounts paid in 2008 and 2007 to the Named Executive Officers for services performed by them during 2007 and 2006.

(2) Represents compensation expense accrued for 2007 and 2006 related to Phantom Common Units granted in 2007, 2006 and 2005. The accruals were made pursuant to SFAS No. 123(R), Share Based Payments. See footnote (1) to the Grants of Plan-Based Awards table presented below.

(3) Represents compensation expense accrued for 2007 and 2006 related to Phantom GP Units granted in 2007 and 2006. The accruals were made pursuant to SFAS No. 123(R). See footnote (1) to the Grants of Plan-Based Awards table presented below.

(4) Includes for 2007: matching contributions under 401(k) plan ($13,500), employer contributions to the Gulf South Money Purchase Plan ($9,000), sale of vacation time ($6,250), club memberships ($4,781), imputed life insurance premiums, travel clubs and preferred parking; for 2006: matching contributions under 401(k) plan ($13,200), employer contributions to the Gulf South Money Purchase Plan ($8,800), club memberships ($6,508), physical medical examination reimbursement, preferred parking, sporting event tickets and imputed life insurance premiums.

(5) Includes for 2007: matching contributions under 401(k) plan ($13,500), club memberships ($7,200), salary continuation plan ($6,124), imputed life insurance premiums ($2,741) and tax gross-up on spouse travel; for 2006: matching contributions made under a 401(k) plan ($13,200), club memberships ($7,200), spouse travel, tax gross-up on spouse travel and imputed life insurance premiums. The total included in the change in pension value and nonqualified deferred compensation column for 2007 and 2006 includes the change in qualified retirement plan account balance ($64,897 and $60,562), interest and pay credits for the supplemental retirement plan ($101,028 and $83,935) and excess nonqualified deferred compensation plan earnings ($11,479 and $9,961).

(6) Includes for 2007: matching contributions under 401(k) plan ($13,500) and imputed life insurance premiums; for 2006: matching contributions made under a 401(k) plan ($13,200), spouse travel and imputed life insurance premiums. The total included in the change in pension value and nonqualified deferred compensation column for 2007 and 2006 includes the change in qualified retirement plan account balance ($31,188 and $28,675) and interest and pay credits for the supplemental retirement plan ($15,414 and $11,658).

(7) Includes for 2007: matching contributions under 401(k) plan ($13,500), employer contributions to the Gulf South Money Purchase Plan ($8,426), imputed life insurance premiums, travel clubs and preferred parking.

(8) Includes for 2007: matching contributions under 401(k) plan ($13,500), employer contributions to the Gulf South Money Purchase Plan ($9,000), imputed life insurance premiums, travel clubs and preferred parking.

(9) Includes for 2007: matching contributions under 401(k) plan ($8,481), sale of vacation time ($10,385), employer contributions to the Gulf South Money Purchase Plan ($8,654), imputed life insurance premiums, travel clubs and preferred parking.

(10) H. Dean Jones II has resigned as an officer and director in conjunction with his announced retirement that will be effective March 1, 2008.

Grants of Plan-Based Awards

The following table displays information regarding grants during 2007 and 2006 to our Named Executive Officers of plan-based awards, including Phantom GP Unit awards under our Strategic Long Term Incentive Plan and Phantom Common Unit awards under our Long Term Incentive Plan:

Grants of Plan-Based Awards

		Estimated future payouts under non-equity incentive plan awards (1)			Estimated future payouts under equity incentive plan awards						
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	All other stock awards: number of shares of stock or units (#)	All other options awards: number of securities underlying options (#)	Exercise or base price of option awards ($/sh)	Grant Date Fair Value of Stock and Option Awards ($) (2)
Rolf A. Gafvert:											
	12/14/07	-	-	1,250,000	-	-	-	6,532	-	-	200,000
	12/20/06	-	-	1,250,000	-	-	-	6,427	-	-	200,000
	7/24/06	-	-	1,250,000	-	-	-	-	-	-	-
H. Dean Jones II:											
	12/20/06	-	-	750,000	-	-	-	2,571	-	-	80,000
	7/24/06	-	-	750,000	-	-	-	-	-	-	-
Jamie L. Buskill:											
	12/14/07	-	-	600,000	-	-	-	-	-	-	-
	12/20/06	-	-	500,000	-	-	-	1,205	-	-	37,500
	7/24/06	-	-	600,000	-	-	-	-	-	-	-
Brian A. Cody:											
	12/14/07	-	-	500,000	-	-	-	3,266	-	-	100,000
John C. Earley Jr.:											
	12/14/07	-	-	450,000	-	-	-	3,266	-	-	100,000
Michael E. McMahon:											
	12/14/07	-	-	450,000	-	-	-	3,266	-	-	100,000

(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 14, 2007 Messrs. Gafvert, Buskill, Cody, Earley, and McMahon were awarded 25, 12, 10, 9 and 9 Phantom GP Units that have a 4.0 year vesting period. On December 20, 2006, Messrs. Gafvert, Jones and Buskill were awarded 25, 15 and 10 Phantom GP Units that have a 4.0 year vesting period. Concurrent with the approval of the Plan, on July 24, 2006, Messrs. Gafvert, Jones and Buskill were awarded 25, 15 and 12 Phantom GP Units that have a 3.5 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 14, 2007 grants, December 20, 2006 grants and July 24, 2006 grants were $50,000, $50,000 and $27,422, respectively, per GP Phantom Unit. The fair value of the awards will be recognized ratably over the vesting period. As of December 31, 2007, the remeasured fair value of each of the December 14, 2007, December 20, 2006 and July 24, 2006 grants was $50,000. See footnote (2) to the Outstanding Equity Awards at Fiscal Year –End table presented below. Note 9 in Item 8 of this Report contains more information regarding our SLTIP.

(2) Reflects the fair value at the date of grant of Phantom Common Units under our LTIP. The closing price of our common units on such date on the NYSE for 2007 was $30.62 and for 2006 was $31.12. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50.0% on the second anniversary of the grant date and 50.0% 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 9 in Item 8 of this Report contains more information regarding our LTIP.

Outstanding Equity Awards at Fiscal Year-End

The table displayed below shows the total outstanding equity awards in the form of Phantom Common Units, awarded under our LTIP and held by our Named Executive Officers at December 31, 2007 and 2006:

Outstanding Equity Awards at Fiscal Year End										
		Option Awards					Stock Awards			
Name	Year	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock that Have Not Vested (#)(1)	Market Value of Shares or Units of Stock that Have not Vested ($)(2)	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	2007	-	-	-	-	-	16,974	541,074	-	-
	2006	-	-	-	-	-	14,457	456,155	-	-
H. Dean Jones II	2007						4,712	152,929	-	-
	2006	-	-	-	-	-	6,854	216,888	-	-
Jamie L. Buskill	2007						2,142	69,470	-	-
	2006	-	-	-	-	-	3,079	97,366	-	-
Brian A. Cody	2007	-	-	-	-	-	7,148	226,112	-	-
John C. Earley Jr.	2007	-	-	-	-	-	7,817	248,309	-	-
Michael E. McMahon	2007	-	-	-	-	-	7,148	226,112	-	-

(1) On December 14, 2007, Messrs. Gafvert, Cody, Earley and McMahon were awarded additional grants of Phantom Common Units in the amount of 6,532, 3,266, 3,266 and 3,266. On the December 14, 2007 grant date the closing sale price on the NYSE was $30.62. On December 20, 2006, Messrs. Gafvert, Jones and Buskill were awarded additional grants of Phantom Common Units in the amount of 6,427, 2,571 and 1,205. On the December 20, 2006 grant date the closing sale price on the NYSE was $31.12. On December 15, 2005, Phantom Common Units were awarded to Gafvert, Jones and Buskill in the amount of 8,030, 4,283 and 1,874. The vesting period is 3.5 years. On the grant date, the closing sales price on the common units on the NYSE was $18.68.

(2) The market value per share reported in the above table is based on the NYSE last sale price on December 31, 2007 of $31.10 and December 29, 2006 of $30.82. Included in the market value is the accumulated non-vested amounts related to the DER that were tandem grants to the Phantom Common Units referred to in footnote (1) above. Such DER amounts for Messrs. Gafvert, Jones, Buskill, Cody, Earley and McMahon were $13,183, $6,386, $2,854, $3,809, $5,200 and $3,809 in 2007 and for Messrs. Gafvert, Jones and Buskill were $10,590, $5,648 and $2,471 in 2006

Option Exercises and Stock Vested

All of the equity-based awards granted to our Named Executive Officers have been in the form of Phantom Common Units. We have not issued any awards in the form of options on our units to any employees including Named Executive Officers.

		Options Awards		Stock Awards (1)	
Name	Year	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)	Value Received on Vesting ($)
Rolf A. Gafvert	2007	-	-	4,015	135,200
H. Dean Jones II	2007			2,142	72,129
Jamie L. Buskill	2007			937	31,552
Brian A. Cody	2007	-	-	669	22,528
John C. Earley Jr.	2007	-	-	1,339	45,090
Michael E. McMahon	2007	-	-	669	22,528

(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.

Pension Benefits

The table displayed below shows the present value of accumulated benefits for our Named Executive Officers. Pension benefits include both a qualified defined benefit cash balance plan and a non-qualified defined benefit supplemental cash balance plan (SRP).

Pension Benefits

Name	Year	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During 2007 ($)	Payments During 2006 ($)
H. Dean Jones II	2007	TGRP	27.1	535,760	-	-
		SRP	27.1	677,339	-	-
	2006	TGRP	26.1	470,863	-	-
		SRP	26.1	576,311	-	-
Jamie L. Buskill	2007	TGRP	21.3	173,837	-	-
		SRP	21.3	34,293	-	-
	2006	TGRP	20.3	142,649	-	-
		SRP	20.3	18,879	-	-

The Texas Gas Retirement Plan (TGRP) is a qualified defined benefit cash balance plan. Although this plan was closed to new participants in November 2006, most of our Texas Gas employees are eligible to participate in the TGRP. 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. 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. At December 31, 2007, Mr. Jones was eligible for the age 55 early retirement provisions of the TGRP.

The credited years of service appearing in the table above are the same as actual years of service. No payments were made to the Named Executive Officers during 2007 or 2006. The present value of accumulated benefits payable to each of the Named Executive Officers, including the number of years of service credited to each Named Executive Officer, is determined using assumptions consistent with the assumptions used for financial reporting. Interest is credited to the cash balance at December 31, 2007, commencing in the year 2008, 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, 2007, 2006, and 2005 were 4.79%, 4.85% and 4.47% and for future years, 4.5%, 4.25%, and 4.125%. The future normal retirement date accumulated cash balance is then discounted using an interest rate at December 31, 2007, 2006 and 2005 of 6.0%, 5.75% and 5.625%. The increase in the present value of accumulated benefit for the TGRP between December 31, 2007 and 2006 of $64,897 for Mr. Jones and $31,188 for Mr. Buskill is reported as compensation in the Summary Compensation Table above. The increase in the present value of accumulated benefit for the TGRP between December 31, 2006 and 2005 of $60,562 for Mr. Jones and $28,675 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 each Named Executive Officer for earnings that exceed the IRC compensation limitations for qualified defined benefit plans. The present value of accumulated benefit is calculated in the same manner as for TGRP. The increase in the present value of accumulated benefit for the SRP between December 31, 2007 and 2006 of $101,028 for Mr. Jones and $15,414 for Mr. Buskill is reported as compensation in the Summary Compensation Table above. The increase in the present value of accumulated benefit for the SRP between December 31, 2006 and 2005 of $83,935 for Mr. Jones and $11,658 for Mr. Buskill is reported as compensation in the Summary Compensation Table above.

Nonqualified Deferred Compensation

The following table shows nonqualified deferred compensation plan information for our Named Executive Officers. We currently do not have a nonqualified deferred compensation plan that allows for current or future deferrals of compensation. The amounts shown in the table are related to the Texas Gas Salary Continuation Plan that is closed to new participants and compensation deferrals:

Nonqualified Deferred Compensation (1)

Name	Year	Executive Contributions ($)	Registrant Contributions ($)	Aggregate Earnings ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance ($)
H. Dean Jones II	2007	-	-	26,313	-	275,969
	2006	-	-	23,524	-	249,656

(1) The Salary Continuation Plan became closed to new participants and compensation deferrals in 1995. The only activity in the plan is the addition of earnings on individual account balances and any withdrawals from account balances. Earnings on the deferred compensation balances are computed at the prime rate of interest plus 2.0%, compounded monthly. Aggregate earnings in 2007 include $11,479 and in 2006 include $9,961 reported in the Summary Compensation Table above.

Potential Payments Upon Termination or Change-in-Control

We have made grants of Phantom Common Units and Phantom GP Units, subject to vesting, to each of our Named Executive Officers, as discussed elsewhere in this Report. Each of the foregoing grants will vest immediately and become payable to the executive in cash upon a change of control of us, as defined in the applicable plan, or upon the termination of the executive's employment with us and our affiliates by reason of death, disability, retirement or termination by us other than for cause (as defined in such plans); provided, that with respect to the vesting of Phantom GP Units, the minimum distribution amount per unit (as defined in the applicable grant agreements) must have been met for the four consecutive calendar quarters ending on or immediately preceding such termination of employment. Assuming that a termination or change of control event resulting in accelerated vesting had occurred as of December 31, 2007, the Named Executive Officer (i) would be entitled to payment for each Phantom Common Unit held as of such date in an amount equal to $31.10, being the closing price of a common unit on such date on the NYSE, plus the distribution equivalent rights accumulated for such Phantom Common Unit from the date of grant; and (ii) would not be entitled to any payment on account of Phantom GP Units since the Minimum Distribution Amount was not met as of such date for any outstanding Phantom GP Units.

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 is paid an annual cash retainer of $35,000 ($40,000 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 officers or employees of us, our subsidiaries, our general partner or an affiliate of our general partner do not receive the compensation described above. 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 director compensation for 2007:

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (3)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation including perquisites ($)	Total ($)
William R. Cordes	49,000	18,305	-	-	-	-	67,305
Thomas E. Hyland	56,000(2)	18,305	-	-	-	-	74,305
Mark L. Shapiro	50,000	18,305	-	-	-	-	68,305

(1) Represents amounts paid in cash for 2007.
(2) Chairman of Audit Committee.
(3) On March 5, 2007, Messrs. Cordes, Hyland and Shapiro were each granted 500 common units. The units were purchased from the NYSE on February 27, 2007 at a unit price of $36.61.

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Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information, at February 15, 2008, as to the beneficial ownership of our common and subordinated units by beneficial holders of 5.0% 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:

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned (1)	Subordinated Units Beneficially Owned	Percentage of Subordinated Units Beneficially Owned (1)	Percentage of Total Equity Securities Beneficially Owned
Jamie L. Buskill	-	-	-	-	-
Brian A. Cody	-	-	-	-	-
William R. Cordes	500	*	-	-	-
John C. Earley Jr.	-	-	-	-	-
Rolf A. Gafvert	-	-	-	-	-
Thomas E. Hyland	6,000	*	-	-	-
Michael E. McMahon	-	-	-	-	-
Jonathan E. Nathanson	15,000	*	-	-	-
Arthur L. Rebell	39,083(2)	*	-	-	-
Mark L. Shapiro	11,000	*	-	-	-
Andrew H. Tisch	18,550(3)	*	-	-	-
All directors and executive officers as a group	90,133	*	-	-	-
BPHC (4)	53,256,122	58.75%	33,093,878	100.00%	70.38%
Loews Corporation (4)	53,256,122	58.75%	33,093,878	100.00%	70.38%

*Represents less than 1.0% of the outstanding common units

(1) As of February 15, 2008, we had 90,656,122 common units and 33,093,878 subordinated units issued and outstanding.

(2) 33,083 of these units are owned by Arebell, LLC, a limited liability company controlled by Mr. Rebell.

(3) 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.

(4) 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.

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, 2007, 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	3,522,500

Note 9 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 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 Audit Committee. "Related person" means our general partner and its directors and executive officers, holders of more than 5.0% 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 Audit 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. See Note 1 and Note 14 in Item 8 of this Report for a description of certain related party transactions.

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 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 $100,000 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 participates in the firm's audit, assurance or tax compliance (but not tax planning) practice 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 2.0% 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, nor do we maintain a compensation or nominating/corporate governance committee.

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 2007 and 2006 by category as described in the notes to the table (in thousands):

	2007	2006
Audit fees (1)	$ 2,216	$ 1,513
Audit related fees (2)	514	553
Tax fees (3)	2	2
Total	$ 2,732	$ 2,068

(1) Includes the aggregate fees and expenses for annual financial statement audit and quarterly financial statements 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, audits of employee benefits plans, Sarbanes-Oxley implementation and other potential acquisitions.

(3) Includes the aggregate fees and expenses for tax professional education services.

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, 2007 and 2006

Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Changes in Member's Equity and Partners' Capital for the years ended December 31, 2007, 2006 and 2005

Consolidated Statements of Comprehensive Income for the years ended December 31, 2007, 2006 and 2005

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, 2007, 2006 and 2005 and are not included in specific schedules herein. These amounts have been deducted from the respective assets on the Consolidated Balance Sheets (in thousands):

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:					
2007	$ 2,610	$ 2,706	$ (4,657)	$ (226)	$ 433
2006	730	2,053	-	(173)	2,610
2005	174	745	(187)	(2)	730
Inventory obsolescence:					
2007	$ 33	$ -	$ 86	$ (33)	$ 86
2006	-	33	-	-	33
2005	201	-	11	(212)	-

(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	Second Amended and Restated Agreement of Limited Partnership of Boardwalk Pipeline Partners, LP dated as of September 19, 2006. (Incorporated by reference to Exhibit 3.1 to Boardwalk Pipeline Partners, LP Current Report on Form 8-K filed on September 25, 2006).
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 (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).
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 Contribution, Conveyance and Assumption Agreement, dated as of November 15, 2005, by and among Boardwalk Pipelines Holding Corp., Boardwalk GP, LLC, Boardwalk Pipeline Partners, LP, Boardwalk Operating GP, LLC, Boardwalk GP, LP, and Boardwalk Pipelines, LLC (Incorporated by reference to Exhibit 10.1 to the Registrant's Current Report on Form 8-K filed on November 18, 2005).

10.5 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).

10.6 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).

10.7	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).
10.8	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).
10.9	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).
10.10	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).
10.11	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).
10.12	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).
10.13	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)
10.14	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).
10.15	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).

10.16	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).
10.17	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).
10.18	Letter Agreement, dated November 10, 2006, between Boardwalk Pipeline Partners, LP and Enterprise Gas Marketing L.P. (Incorporated by reference to Exhibit 10.1 to the Registrant's current Report on Form 8-K filed on November 14, 2006).
*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

(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 26, 2008

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 26, 2008	/s/ Rolf A. Gafvert Rolf A. Gafvert President, Chief Executive Officer and Director (principal executive officer)
Dated: February 26, 2008	/s/ Jamie L. Buskill Jamie L. Buskill Senior Vice-President, Chief Financial Officer and Treasurer (principal financial officer)
Dated: February 26, 2008	/s/ Steven A. Barkauskas Steven A. Barkauskas Vice President, Controller and Chief Accounting Officer (principal accounting officer)
Dated: February 26, 2008	/s/ William R. Cordes William R. Cordes Director
Dated: February 26, 2008	/s/ Thomas E. Hyland Thomas E. Hyland Director
Dated: February 26, 2008	/s/ Jonathan E. Nathanson Jonathan E. Nathanson Director
Dated: February 26, 2008	/s/ Arthur L. Rebell Arthur L. Rebell Director
Dated: February 26, 2008	/s/ Mark L. Shapiro Mark L. Shapiro Director

Dated: February 26, 2008 /s/ Andrew H. Tisch
Andrew H. Tisch
Director