Boardwalk Pipeline Partners, LP
Form 10-K
February 23, 2007

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, 2006

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.)

3800 Frederica Street, Owensboro, Kentucky 42301
(270) 926-8686
(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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer.
(See definition of "Accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.) (check one)
Large accelerated filer o Accelerated filer x Non-accelerated filer 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, 2006 was approximately $367,350,000. As of February 9, 2007, the registrant had 75,156,122 common units outstanding.

Documents incorporated by reference. None.

TABLE OF CONTENTS

2006 FORM 10-K

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, Texas Gas Transmission, LLC (Texas Gas) and Gulf South Pipeline Company, LP (Gulf South) (together, operating subsidiaries). We completed our initial public offering (IPO) of 15.0 million common units in November 2005 and, in the fourth quarter 2006, we sold 6.9 million common units in a follow-on public offering. The common units sold in our IPO and follow-on offerings represent approximately 19.8% of partners' capital which includes common units, subordinated units and a 2% general partner interest. All of our common and subordinated units, other than the common units sold in the public offerings, are held by Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews). Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 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 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 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. For the year ended December 31, 2006, approximately 62% of our revenues were derived from capacity reservation charges under firm contracts, approximately 17% of our revenues were derived from other charges based on actual utilization under firm contracts and approximately 21% of our revenues were derived from interruptible transportation, interruptible storage and parking and lending (PAL) and other services.

Our Pipeline and Storage Systems

We own and operate two interstate natural gas pipeline systems, with approximately 13,400 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 2006, our pipeline systems transported approximately 1,340 billion cubic feet (Bcf) of gas. Average daily throughput on our pipeline systems during 2006 was approximately 3.7 Bcf. Our natural gas storage facilities are comprised of eleven underground storage fields located in four states with aggregate working gas capacity of approximately 146 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 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 Texas Gas System

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

- approximately 5,900 miles of pipeline, having a peak-day delivery capacity of approximately 3.2 Bcf per day which includes deliveries to pipeline interconnects in South Louisiana;
- 31 compressor stations having an aggregate of approximately 536,000 horsepower; and
- nine natural gas storage fields located in Indiana and Kentucky, having aggregate storage capacity of approximately 178.0 Bcf of gas, of which approximately 63.0 Bcf is designated as working gas.

Texas Gas's direct market area 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 Texas Gas's 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.

Our Gulf South System

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

- approximately 7,500 miles of pipeline, having a peak-day delivery capacity of approximately 3.5 Bcf per day;
- 29 compressor stations having an aggregate of approximately 225,000 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 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 LDC and municipality load serving communities 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.

Expansion Projects

Carthage to Keatchie Loop. We have constructed a 20.5 mile segment of 42-inch pipeline from Carthage, Texas to Keatchie, Louisiana which was placed in service in December 2006. The current capacity of this loop is 120 MMcf per day.

East Texas to Mississippi Expansion. We are pursuing a pipeline expansion project consisting of 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression. The expansion would add approximately 1.7 Bcf per day of new transmission capacity to our Gulf South pipeline system. The natural gas to be transported on this expansion will originate primarily from the Barnett Shale and Bossier Sands producing regions of East Texas. The expansion will transport natural gas to new interstate pipeline interconnects in the Perryville, Louisiana area and existing pipeline interconnects with other pipelines east of the Mississippi River. This project is supported by binding precedent agreements with customers who have contracted, on a long-term basis (with a weighted average term of approximately 7 years), for 1.3 Bcf per day from Carthage, Texas with an option for an additional 100 MMcf per day. On September 1, 2006, we filed a certificate application relating to this project with the FERC. We expect this project to be in service during the fall of 2007.

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 a new subsidiary, Gulf Crossing Pipeline Company LLC (Gulf Crossing), and will consist of approximately 355 miles of 42-inch pipeline having capacity of up to approximately 1.6 Bcf per day. Additionally, Gulf Crossing will enter into: (i) a lease for at least 1.1 Bcf per day of capacity on our Gulf South pipeline system (including on the Southeast Expansion and 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; and (ii) a lease with a third-party intrastate pipeline which will bring certain gas supplies to our system. This project is supported by binding agreements with customers who have contracted for 1.1 Bcf per day of capacity under firm contracts having terms of 5 to 10 years (with a weighted average term of approximately 9.8 years), and options with certain of these customers for an additional 350 MMcf per day of capacity. We anticipate making the required filings with the FERC by July 2007 and for the project to be in service during the fourth quarter of 2008. We are in negotiations with one of the foundation shippers supporting this project concerning the purchase of 49.0% of the equity of Gulf Crossing.

Southeast Expansion. We are pursuing a pipeline expansion extending our Gulf South pipeline system from near Harrisville, Mississippi to an interconnect with Transco in Choctaw County, Alabama which will enhance our ability to deliver gas to the Northeast through other pipeline interconnects. This expansion will consist of approximately 112 miles of 42-inch pipeline having initial capacity of approximately 1.2 Bcf per day, expandable to as much as 2.0 Bcf per day to accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above. In addition, Gulf South has executed a lease with Destin Pipeline Company to access markets in Florida. This project is supported by binding agreements with customers who have contracted for 660 MMcf per day of capacity under firm contracts having terms of 5 to 10 years (with a weighted-average term of 9.2 years), as well as the capacity leased to Gulf Crossing discussed above. The certificate filing was made with the FERC in December 2006 and the project is anticipated to be in service during first quarter 2008.

Fayetteville Shale. 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 Texas Gas. The Fayetteville Lateral, consisting of approximately 165 miles of 36-inch pipeline, is anticipated to have an initial design capacity of 800 MMcf per day and a maximum design capacity of 1.1 Bcf per day. This lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas area to an interconnect with Texas Gas's mainline in Coahoma County, Mississippi. The Greenville Lateral, consisting of approximately 95 miles of pipeline with an initial design capacity of 750 MMcf per day, will originate at Texas Gas's mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi area. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast, including the Henry Hub. Construction of both laterals is supported by a binding precedent agreement with Southwestern Energy Services Company, a wholly-owned subsidiary of Southwestern Energy Company. In December 2006, the FERC granted Texas Gas's request to initiate the pre-filing process for this project and we anticipate making the required certificate filings with the FERC in June 2007. We expect the project to be in service during the first quarter 2009.

The total cost of the pipeline expansion projects discussed above is expected to be approximately $3.3 billion (before taking into account equity that would be contributed by the purchaser of a 49.0% interest in Gulf Crossing Pipeline referred to above). We constantly seek to optimize these projects to reduce the overall cost. However the actual cost to complete these projects may exceed our current estimate as a result of, among other things, higher labor and materials costs due to the large number of pipeline projects under way throughout the industry or our need to expand pipeline capacity if we contract for additional volumes. For a further discussion of the risks associated with these projects, see the section on Risk Factors in Item 1A of this Report.

Western Kentucky Storage Expansion. In December 2006, the FERC issued a certificate approving Texas Gas's Phase II storage expansion project which will expand the working gas capacity in its 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 for the full additional capacity at Texas Gas's maximum applicable rate. We expect this project to cost approximately $40.7 million and to be in service by November 2007. In December 2006, Texas Gas commenced an open season related to a potential third expansion of its storage facilities. Texas Gas has signed one precedent agreement for 2.0 Bcf of capacity. The ultimate size of the Phase III storage expansion will be determined, in part, by the open season. The Phase III storage expansion is subject to the FERC approvals, including potential market-based rate authority for the additional new storage capacity being created. Phase I of this project which expanded working gas capacity by approximately 8.0 Bcf was completed and in service in November 2005.

Magnolia Storage Facility. We are currently developing an additional storage cavern near Napoleonville, Louisiana. During mining operations, certain issues have arisen causing the mining of the cavern to be suspended. We are continuing to conduct operational integrity tests on the caverns. The tests are on-going but have been delayed due to lack of equipment availability needed to complete the testing. If the test results are favorable, we expect the storage facilities to be in service perhaps as early as 2008 with working gas capacity of 2.0 Bcf, reduced from 6.0 Bcf as originally designed. If the test results are not favorable, we will consider the options it has available, including developing a new cavern, or the sale or abandonment of the project.

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 three months to ten years, although short-term firm transportation services can be offered with daily terms. 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. Generally, interruptible transportation agreements have terms of thirty days or less.

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 five years. Interruptible storage customers pay for the volume of gas actually stored. Generally, interruptible storage agreements range from one to twelve months. Unlike most other FERC-regulated pipelines, including Texas Gas, Gulf South is authorized to charge market-based rates for its firm and interruptible storage services.

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 pull 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.

PAL 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 pipelines 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. Gulf South's customers are located throughout its service area and elsewhere or are accessed through numerous interconnects on unaffiliated pipeline systems. In contrast, the Texas Gas system primarily moves gas for its customers in a northeasterly direction to serve markets directly connected to the Texas Gas system and also serves indirect customer markets through interconnects with other interstate pipelines.

Based upon 2006 revenues, our customer mix was comprised as follows: LDCs (35%), pipeline interconnects (33%), storage (14%), industrial end-users (6%), power plants (6%) and miscellaneous other (6%). We contract directly with customers connected to our system and with marketers, producers and other third parties who provide transportation and storage services to end users not directly connected with our system.

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, 2006. 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 use storage to facilitate trading opportunities, and producers 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 proposed Rockies Express Pipeline that would transport natural gas from northern Colorado to eastern Ohio; the Heartland Gas Pipeline currently being constructed in Indiana; the proposed Mid-Continent Express Pipeline that would transport gas from Texas to Alabama; and the proposed Southeast Header Supply System that would transport gas from Perryville, Louisiana to markets in Florida. 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, 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 2006, approximately 57% 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 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 FERC rate-making process. Key determinants in the rate-making process are the costs of providing service, the allowed rate of return on capital investments, volume throughput assumptions, the allocation of costs and the rate design. The allowed rate of return must be approved by the FERC in each rate case. Texas Gas filed a rate case in 2005, which was settled in the second quarter of 2006. Texas Gas has no obligation to file a new rate case and is prohibited from placing new rates into effect prior to November 1, 2010. Gulf South has no 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, 2006, we had approximately 1,150 employees, approximately 90 of which are covered by a collective bargaining agreement, which will expire on April 30, 2007. A satisfactory relationship continues to exist between management and labor. Approximately 100 employees, included in the total employee count at December 31, 2006, elected to retire under an early retirement incentive program (ERIP) offered to approximately 240 employees at

Texas Gas. Most of the retirements were effective January 1, 2007, and the remainder will be effective by the end of 2007. 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 substantially all Texas Gas employees. Note 9 in Item 8 of this Report contains further discussion of our employee benefits.

Available Information

Our internet website is located at *www.boardwalkpipelines.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, 3800 Frederica Street, Owensboro, Kentucky, 42301.

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, 3800 Frederica St., Owensboro, KY 42301, 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, 3800 Frederica St., Owensboro, KY 42301, 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 significant 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 significant 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.

We may not complete expansion projects that we commence, or we may complete projects on materially different terms or timing than initially anticipated and we may not be able to achieve the intended benefits of any such project, if completed.

We have announced significant expansion projects and may consider additional expansion projects in the future. We anticipate that we will be required to seek additional financing in the future to fund our current and future expansion projects and we may not be able to secure such financing on favorable terms, or at all. In addition, we may not be able to complete the expansion projects on time as a result of weather conditions, delays in obtaining or failure to obtain regulatory approvals, delays in obtaining key materials, labor difficulties and land owner opposition, difficulties with partners or potential partners or other factors beyond our control. If we do not meet designated schedules for approval and construction of our expansion projects, certain of our customers may have the right to terminate their precedent agreements relating to the expansion projects. Certain customers may also have the right to receive liquidated damages. Even if expansion projects are completed, the total costs of the expansion projects may be higher than anticipated and the performance of our business following the expansion projects may not meet expectations. Further, we may not be able to timely and effectively integrate the expansion projects into our operations, such integration may result in unforeseen operating difficulties or unanticipated costs and the expansion projects might divert the attention of management from our other business concerns. Any of these or other factors could adversely affect our ability to realize the anticipated benefits from the expansion projects and thus have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our natural gas transportation, gathering and storage operations are subject to FERC 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.

Action by the FERC on currently pending matters as well as matters arising in the future could adversely affect our ability to establish rates, or to charge rates that would cover future increases in our costs, or even to continue to collect rates that cover current costs. 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 Texas Gas or Gulf South could have a material adverse effect on our business, financial condition, results of operations and cash flows.

On July 20, 2004, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued its opinion in *BP West Coast Products, LLC v. FERC (BP West Coast)* and vacated the portion of the FERC's decision applying the FERC's *Lakehead* policy to determine an allowance for income taxes in the regulated cost of service. In its *Lakehead* decision, the FERC allowed an oil pipeline limited partnership to include in its cost of service an income tax allowance to the extent that its unitholders were corporations subject to income tax. The D.C. Circuit emphasized that a regulated pipeline's cost of service should include only "appropriate cost[s]" and compared income taxes paid by owners of equity interests in a pipeline to the costs of bookkeeping paid by such owners, indicating the court's belief that such costs paid by an entity other than the regulated entity would not be recoverable in the rates of the pipeline. In May and June 2005, the FERC issued a statement of general policy and an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost-of-service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline's owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails risk due to the case-by-case review requirement. In December 2005, the FERC issued a case-specific review of the income tax allowance issue in the *SFPP, L.P.* proceeding. The FERC ruled favorably to SFPP, L.P. on all income tax issues and set forth guidelines regarding the type of evidence necessary for the pipeline to determine its income tax allowance. The FERC's *BP West Coast* remand decision, the new tax allowance policy, and the December 2005 order have been appealed to the D.C. Circuit. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC's treatment of income tax allowances in cost of service. If the FERC were to change its tax allowance policies in the future, or if current policy was reversed or changed on appeal by a court, such changes could materially and adversely impact the rates we are permitted to charge as future rates are approved for our interstate transportation services.

***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 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.

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.

Catastrophic losses are unpredictable.

Catastrophic losses may be an inevitable part of our business. Various events can cause catastrophic losses, including hurricanes, windstorms, earthquakes, hail, explosions, and severe winter weather and fires, the frequency and severity of these events are inherently unpredictable. Although we carry insurance, the coverage could be insufficient.

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. 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 Office of Pipeline Safety (OPS) 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.

The final rule requires operators 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 OPS 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 several new pipeline projects that are under way, including the proposed Rockies Express Pipeline that would transport natural gas from northern Colorado to eastern Ohio, the Heartland Gas Pipeline currently being constructed in Indiana, the proposed Mid-Continent Express Pipeline that would transport gas from Texas to Alabama and the proposed Southeast Header Supply System that would 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 could adversely affect our business and operating results.

For the years 2003 to 2005, gas production from the Gulf Coast region, which supplies the majority of our throughput, has declined on average approximately 11% per year according to the Energy Information Administration (EIA). A large part of this decline was due to the effects of Hurricanes Katrina and Rita 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% greater than pipeline capacity leaving that point, creating a bottleneck for supply into areas of high demand. As of December 31, 2006, approximately 21% of our long-term contracts with firm deliveries to Lebanon expire by the end of 2007. 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, a new proposed pipeline from the Rockies, 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, 2006, approximately 14% of the firm contract load on our pipeline systems was due to expire on or before December 31, 2007. 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, 2006, ProLiance Energy, LLC and Atmos Energy accounted for approximately 18.35% 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, our Gulf South pipeline can deliver approximately 500 MMcf per day to Texas Eastern at Kosciusko, Mississippi. If this or any other 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.

Expansion projects and acquisitions involve risks that may adversely affect our business.

A principal focus of our strategy is to continue to grow our business through acquisitions, expansion of existing assets and construction of new assets. Any acquisition, expansion or new construction involves potential risks, including:

· performance of our business following the acquisition, expansion or construction of assets that does not meet expectations;

· a significant increase in our indebtedness and working capital requirements, which could, among other things, have an adverse impact on our credit ratings;

· the inability to timely and effectively integrate into our operations the operations of newly acquired, expanded or constructed assets;

· the incurrence of substantial unforeseen environmental and other liabilities, including liabilities arising from the operation of an acquired business or asset prior to our acquisition for which we are not indemnified or for which the indemnity is inadequate;

· diversion of our management's attention from other business concerns; and

· regulatory risks created by the nature or location of acquired businesses.

Any of these factors could adversely affect our ability to realize the anticipated benefits from newly acquired, expanded or constructed assets and meet our debt service requirements. The process of integrating newly acquired, expanded or constructed assets into our operations may result in unforeseen operating difficulties or unanticipated costs that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

If we do not complete expansion projects or make acquisitions on economically acceptable terms, our future growth may be limited.

Our ability to grow depends on our ability to complete expansion and construction projects and make acquisitions. We may be unable to complete successful expansion and construction projects or make accretive acquisitions for any of the following reasons:

· we are unable to identify attractive expansion projects or acquisition candidates or we are outbid by competitors;

· we are unable to obtain necessary governmental approvals;

· we are unable to raise financing for such expansions or acquisitions on economically acceptable terms; or

· we are unable to secure adequate customer commitments to use the expanded or acquired facilities.

Recently, competition from other buyers for natural gas pipelines and related assets and businesses has intensified. This competition may reduce our acquisition opportunities or cause us to pay a higher price than we might otherwise pay. If any of these events occurred, our future growth could be limited.

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.

A subsidiary of Loews owns 78.2% of the limited partner interests in us and will continue to own and control 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% of the outstanding common units or (2) all of our equity securities (including common units) if it and its affiliates own more than 50% in the aggregate of the outstanding common units, 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 in 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.

Our credit agreement contains operating and financial restrictions that may limit our business and financing activities.

The operating and financial restrictions and covenants in our credit agreement and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities. For example, our credit agreement restricts or limits our ability to:

· make certain loans or investments;

- make any material change to the nature of our business, including consolidations, liquidations or dissolutions;
- enter into a merger, consolidation, sale and leaseback transaction or sale of assets;
- make distributions if any default or event of default occurs;
- incur additional indebtedness or guarantee other indebtedness; or
- grant liens or make certain negative pledges.

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 deteriorate, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreement, a significant portion of our indebtedness may become immediately due and payable, and our lenders' commitment to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments.

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 a material amount of entity-level taxation for state tax purposes, then our cash distributions to our unitholders would 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%, and would likely pay 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 a material amount of entity-level taxation. In addition, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other form of taxation. Imposition of such a tax on us will 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.

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 our tax counsel’s conclusions. It may be necessary to resort to administrative or court proceedings to sustain some or all of our tax counsel’s conclusions or the positions we take. A court may not agree with some or all of our tax counsel’s conclusions or the positions we take. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. 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 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 foreign 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 (known as IRAs), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to organizations that are exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will 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 foreign 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.

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

We will be considered terminated for federal income tax purposes, if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Our termination would, among other things, result in the closing of our taxable year for all unitholders and could result in a deferral of depreciation deductions allowable in computing our taxable income.

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. Our counsel has not rendered an opinion on the state or local tax consequences of an investment in the common units.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We and Texas Gas are headquartered in approximately 108,000 square feet of office space in Owensboro, Kentucky in a building that is owned by Texas Gas. Gulf South has its headquarters in approximately 55,000 square feet of leased office space located in Houston, Texas. The lease for our Houston offices expires in May 2007 and, accordingly, we have signed a ten-year lease for approximately 74,000 square feet of office space in a new location in Houston, Texas. 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 9, 2007, we had 75,156,122 common units outstanding, held of record by approximately 27 holders, BPHC owns 52,356,122 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 9, 2007 was $35.46 per unit.

	Sales Price Range per Common Unit		Cash Distributions per Unit
	High	Low	(a)
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
Year ended December 31, 2005			
Fourth quarter (b)	19.23	17.58	0.179 (c)

(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.
(b) For the period from November 15, 2005, the date of our IPO, through December 31, 2005.
(c) The distribution for the fourth quarter 2005 represents a pro-rated distribution of $0.35 per common and subordinated unit for the period from November 15, 2005 through December 31, 2005.

Our Cash Distribution Policy

Our cash distribution policy reflects a basic judgment that our unitholders will be better served by our distributing our available cash surplus rather than retaining it. 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.

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, the 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% interest, if we have made 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%	2%
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target Distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	above $0.5250	50%	50%

Subordination Period

During the subordination period, 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% 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% 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 four quarter period 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 March 23, 2006, our general partner purchased 1,000 of our common units in the open market at a price of $21.38 per unit. These units were granted to our independent directors on March 24, 2006, as part of their director compensation. See Executive Compensation - Director Compensation in Item 11 of this Report.

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 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 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 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 are not readily comparable with our results of operations for the years ended December 31, 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 a charge-in-lieu of income taxes or certain state franchise taxes incurred by BPHC and no longer participate in a tax-sharing agreement with Loews or tax sharing policy with BPHC. One of our subsidiaries directly incurs some income-based state taxes which are shown as Income taxes and charge-in-lieu of income taxes on the 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):

	Boardwalk Pipeline Partners				**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,**	**For the Year Ended December 31,**
	2006	**2005**	**2004**	**2003**	**2003**	**2002**

(expressed in thousands)						
Total operating revenues	$ 607,642	$ 560,466	$ 263,621	$ 142,860	$ 113,447	$ 266,674
Net income	197,550	100,925	48,825	22,451	34,474	56,099
Total assets	2,951,299	2,465,491	2,472,140	1,238,627	N/A	1,412,148
Long-term debt	1,350,920	1,101,290	1,106,135	548,115	N/A	249,781
Earnings per common and subordinated unit	$ 1.85	*	N/A	N/A	N/A	N/A
EBITDA**	$ 331,468	$ 289,002	$ 144,489	$ 77,241	$ 78,380	$ 149,569

* 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 net income, operating income, cash flow from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. 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 should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with generally accepted accounting principles or as an indicator of our operating performance or liquidity. 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				**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,**	**For the Year Ended December 31,**
	2006	**2005**	**2004**	**2003**	**2003**	**2002**
Net income	$ 197,550	$ 100,925	$ 48,825	$ 22,451	$ 34,474	$ 56,099
Income taxes and charge-in-lieu of income taxes	253	49,494	32,333	15,104	22,387	36,647
Elimination of cumulative deferred taxes	-	10,102	-	-	-	-
Depreciation and amortization	75,771	72,078	33,977	20,544	16,092	37,806
Interest expense	62,123	60,067	30,081	19,368	7,392	20,490
Interest income	(4,202)	(1,478)	(352)	(205)	-	(5)
	(27)	(2,186)	(375)	(21)	(1,965)	(1,468)

Interest income from affiliates, net												
EBITDA	$	331,468	$	289,002	$	144,489	$	77,241	$	78,380	$	149,569

24

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 northward 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 when capacity is available. 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 in advance of the service. Revenues for these agreements are recognized as service is provided over the term of the agreement. For the year ended December 31, 2006, the percentage of our total operating revenues associated with firm contracts was approximately 79.0%.

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.

Trends and Uncertainties

The following trends and uncertainties have had, and are likely to continue to have, a material impact on our results of operations and liquidity:

- increasing competition for the transportation and storage of available gas supplies originating in a number of our supply areas;
- increasing competition from new and proposed pipelines providing natural gas to our market areas from other supply areas;
    - the success of pipeline expansion in areas such as the Barnett Shale and Fayetteville Shale is dependent on natural gas prices being sufficiently high to support continued development in those areas;
- the likelihood that LNG from the Gulf Coast region will become an increasingly important source of supply for our customers;
- a change in the price of natural gas at different locations (basis differentials), which means that the value of the transportation services we offer may change over time based upon macro economic conditions.

We believe the collective impact of the trends and uncertainties described in the first two bullet points above may result in an increasingly competitive gas transportation market. This could result in reduced rates on many of our contracts, adversely affecting revenue and cash flows. We believe that the impact of the factors described in the third and fourth bullet points above may provide us with growth opportunities. The last bullet point may result in reduced rates or provide growth opportunities based upon the level of basis differentials. The last three bullets also result in the need for increasing amounts of capital expenditures to take advantage of opportunities to bring new supplies of natural gas into our systems to maintain or possibly increase our transportation volumes.

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 at the date of 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 period in which the facts that give rise to the revision become known.

Earnings per Unit

We calculate net income per limited partner unit in accordance with Emerging Issues Task Force Issue No. 03-6 (EITF No. 03-6), *Participating Securities and the Two-Class Method under Financial Accounting Standards Board (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 amount reported for net income per limited partner unit on the Consolidated Statements of Income for the year ended December 31, 2006 was reduced 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 and not based on the assumed allocation required by EITF No. 03-6.

Regulation

Certain revenues collected may be subject to possible refunds. Accordingly, estimates of rate refund reserves are recorded considering regulatory proceedings, advice of counsel and estimated risk-adjusted total exposure, as well as other factors. For instance, Texas Gas filed a general rate case with the FERC on April 29, 2005, and implemented new rates on November 1, 2005, subject to refund. As of December 31, 2005, an estimated refund liability of approximately $5.0 million related to the Texas Gas rate case was recorded on our Consolidated Balance Sheets. The outcome of the rate case was determined in the second quarter 2006, and the refund liability was reduced to zero by the amount of cash refunds paid to customers on June 30, 2006. The refund totaling approximately $6.6 million consisted of $6.4 million in principal and $0.2 million in interest. At December 31, 2006, there was no liability for any open rate case recorded on our Consolidated Balance Sheets. Currently, neither Texas Gas nor Gulf South are involved in an open general rate case.

Statement of Financial Accounting Standards (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 Gulf South are priced using market-based rates and competition in Gulf South's market area can result in discounts from the maximum allowable cost-based rates 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. 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. 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. 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 independent consultants and the current facts and circumstances related to these environmental matters. At December 31, 2006, we had accrued approximately $18.4 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 (EPA), the FERC and other governmental authorities on these matters. We continue to conduct environmental assessments and are implementing a variety of remedial measures that may result in increases or decreases in the total estimated environmental costs.

Goodwill

As of December 31, 2006, 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, 2006, 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. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges 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 supplemented our discount rate decision with a yield curve analysis. The yield curve was applied to expected future retirement plan payments to adjust the discount rate to reflect the cash flow characteristics of the plans. The yield curve was 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 operating 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 transportation revenues.

The following analysis discusses our financial results of operations for the years 2006, 2005 and 2004. The acquisition of Gulf South was consummated on December 29, 2004. Three days of activity are included in the 2004 Consolidated

Statements of Income and Cash Flows. The financial activity of Gulf South for those three days is considered immaterial and does not impact discussions below.

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 Katrina and Rita (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 that occurred 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 an increase 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.

2005 Compared with 2004

Our Net income for the year ended December 31, 2005, increased $52.1 million or 106.7% from 2004. The primary driver for the increase was the acquisition of Gulf South on December 29, 2004.

Total operating revenues increased $296.8 million, or 112.6%, to $560.4 million for the year ended December 31, 2005 compared to $263.6 million for the year ended December 31, 2004, primarily due to:

· $259.8 million increase in transportation revenues, substantially all of which was attributable to Gulf South, and increased interruptible revenues due to supply disruptions caused by the hurricanes. Lower revenues from contract renewals and related discounting at the Lebanon terminus of our Texas Gas system were partially offset by new rates, subject to refund, implemented by Texas Gas on November 1, 2005, and by new projects including transportation agreements related to our market area storage expansion project in Western Kentucky and increased capacity from Carthage, Texas by leasing capacity on a third-party pipeline.

· $27.6 million increase in PAL and gas storage revenues of which $29.2 million was attributable to Gulf South. Storage revenues at Texas Gas were lower by $2.0 million primarily as a result of unusually high interruptible storage revenue generated in 2004 due to favorable market conditions; and

· $9.4 million increase in Other revenues of which $11.1 million was attributable to Gulf South.

Operating costs and expenses increased by $191.1 million, or 124.2%, to $345.0 million for the year ended December 31, 2005, compared to $153.9 million for the year ended December 31, 2004. This increase is partially due to:

· $207.4 million increase attributable to Gulf South, $12.9 million of which was due to casualty losses recognized as a result of the hurricanes..

This increase was partly offset by:

· $12.2 million decrease due to the sale of storage gas related to Phase I of our Western Kentucky storage expansion project, partially offset by asset retirements.

Total other deductions increased by $26.4 million, or 92.0%, of which $28.9 million is due to higher interest expense primarily related to debt incurred in 2004 to fund the acquisition of Gulf South.

Recent Expansion Projects

We are currently engaged in several major pipeline and storage expansion projects that we expect will require the investment of approximately $3.3 billion of capital from 2007 to 2009 (before taking into account equity that would be contributed by the purchaser of a 49% interest in Gulf Crossing Pipeline). The pipeline expansion projects will transport natural gas supplies from the Bossier Sands, Barnett Shale, Fayetteville Shale and the Caney/Woodford Shale areas in East Texas, Arkansas and Oklahoma to our existing or new assets and third-party interstate pipeline interconnects in Alabama and Mississippi. For more information on our expansion projects, please see "Recent Expansion Projects" in Item 1 of this Report.

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, as discussed above.

Capital Expenditures

Capital expenditures, net of amounts received for salvage and accrued amounts, for 2006, 2005 and 2004 were as follows (in millions):

	December 31, 2006	December 31, 2005	December 31, 2004
Expansion capital	$ 158.6	$ 30.1	$ 7.7
Maintenance capital	41.7	52.9	34.2
Total	$ 200.3	$ 83.0	$ 41.9

For the year ending December 31, 2007, we expect to make capital expenditures of approximately $1.7 billion, of which we expect approximately $1.6 billion to be for the expansion projects discussed in Item 1 and approximately $60.0 million to be for maintenance capital. The amount of expansion capital we expend in 2007 could vary significantly depending on the progress made with these projects, the number and types of other capital projects we decide to pursue, the timing of any of those projects and numerous other factors beyond our control.

We expect to fund our expansion capital expenditures for 2007 and beyond with proceeds from sales of our debt and equity securities, borrowings under our revolving credit facility and operating cash flows, though we have not made any determination with regard to such financing. We expect to fund our maintenance capital expenditures from operating cash flows.

Equity and Debt Offerings

During the fourth quarter 2006, we completed an offering of 6,900,000 of our common units at a price of $29.65 per unit. The offering resulted in net proceeds of $199.4 million, after deducting underwriting discounts and offering expenses of $9.4 million and including $4.2 million received from our general partner to maintain its 2.0% interest in us.

Also during the fourth quarter of 2006, we completed an offering of $250.0 million of 5.88% senior notes due 2016. We received net proceeds of approximately $248.3 million after deducting underwriting discounts and commissions and offering expenses of $1.7 million.

The proceeds of these offerings will be used to finance our expansion activities. We used $90.0 million of the proceeds to repay outstanding borrowings under our revolving credit facility which were used to finance expansion activities.

To hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through December 1, 2006, on October 5, 2006 we entered into a Treasury rate lock for a notional amount of $250.0 million of principal. The reference rate on the Treasury rate lock was 4.60%. The Treasury rate lock was settled at the time of the closing of our debt offering in November 2006. We received $0.9 million from the counterparty as a result of the settlement of the Treasury rate lock, which has been recorded as a component of accumulated other comprehensive income. The amount of the credit in accumulated other comprehensive income will be recognized in income as a reduction to interest expense on a straight-line basis over the 10-year term of the 5.88% senior notes, resulting in an effective rate of 5.92%, including the effects of the discounts and offering expenses.

In August 2006, we 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 those Treasury rate locks were 5.00% and 4.96%. See Item 7A for more information regarding the Treasury rate locks and interest rate risk.

Credit Facility

We maintain a $400.0 million revolving credit facility under which Boardwalk Pipelines, Texas Gas and Gulf South 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, 2006, we were in compliance with all the covenant requirements under our credit agreement and no funds were drawn under this facility. The revolving credit facility has a maturity date of June 29, 2011.

Contractual Obligations

The following table summarizes significant contractual cash payment obligations as of December 31, 2006, by period (in millions):

		Payments due by Period			
	Total	**Less than 1 Year**	**1-3 Years**	**4-5 Years**	**More than 5 Years**

Lease commitments	$	34.8	$	5.9	$	14.3	$	4.1	$ 10.5
Interest on long-term debt		811.1		72.6		220.2		146.8	371.5
Capital commitments		409.1		403.8		5.2		0.1	-
Principal payments on long-term debt		1,360.0		-		-		-	1,360.0
Total	$	2,615.0	$	482.3	$	239.7	$	151.0	$ 1,742.0

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, 2006 relating to our expansion projects. For information on these projects please read "Capital Expenditures" above.

31

Changes in cash flow from operating activities

Net cash provided by operating activities increased $36.8 million, or 16.8%, to $255.5 million for the year ended December 31, 2006, compared to $218.7 million for the year ended December 31, 2005, primarily due to:

- $54.2 million increase in net income before noncash adjustments for depreciation and amortization, provision for deferred income taxes and gain on disposal of operating assets;
- $17.4 million increase in cash from a reduction in operating assets net of operating liabilities mainly from increases in payables and deferred income on PAL agreements, and decreases in receivables, partly offset by an increase in other current assets primarily from the recognition of unrealized gains on derivatives; and
- $34.8 million decrease in cash from a reduction in other noncurrent liabilities net of noncurrent assets.

Changes in cash flow from investing activities

Net cash used in investing activities increased $89.2 million, or 87.2%, to $191.5 million for the year ended December 31, 2006, compared to $102.3 million for the year ended December 31, 2005, primarily due to:

- $117.4 million increase in capital expenditures mainly related to our expansion projects; and
- $27.5 million reduction in advances to affiliates.

Changes in cash flow from financing activities

Net cash provided by (used in) financing activities increased $336.3 million to $269.2 million provided by financing activities for the year ended December 31, 2006, compared to a use of $67.1 million for the year ended December 31, 2005, primarily due to:

- $419.7 million decrease in cash used from the payment of notes and other long-term debt in 2005 slightly offset by payment in 2006 of interim financing borrowed in 2005 for capital expenditures incurred in connection with the acquisition of Gulf South; and
- $76.2 million decrease in cash provided from public offerings of common units.

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. While amounts in excess of historical cost are not recoverable under current FERC practices, we believe we may be allowed to recover and earn a return based on the increased actual costs incurred when existing facilities are replaced. 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, 2006, 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.

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” statements within the meaning of the Private Securities Litigation Reform Act of 1995 (Act). 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,” “estimat “believe,” “will likely result,” and similar expressions. In addition, any statement 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, which may be provided by management, are also forward-looking statements as defined by the Act.

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 commence, or we may complete projects on materially different terms or timing than anticipated and we may not be able to achieve the intended 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 weather, untimely regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties, difficulties we may encounter with partners or potential partners, expansion cost higher than anticipated and numerous other factors beyond our control.

· 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 from existing wells, 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 long-term debt is subject to interest rate risk. Total long-term debt at December 31, 2006, had a carrying value of $1.4 billion and a fair value of $1.3 billion. The weighted-average interest rate of our long-term debt was 5.40% at December 31, 2006.

In August 2006, we 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 are 5.00% and 4.96%. Under the terms of the rate locks, the counterparties would pay us settlement amounts if the 10-year Treasury rate is greater than the reference rates at October 1, 2007. Conversely, we would pay the counterparties settlement amounts if the 10-year Treasury rate is less than the reference rates. A 10 basis point decrease in the 10-year Treasury rate would result in a $1.6 million favorable change in the value of the rate locks. Conversely, a 10 basis point increase in the 10-year Treasury rate would result in a $1.6 million unfavorable change in the value of the rate locks. The Treasury rate locks were designated as cash flow hedges in accordance with SFAS No. 133. As of December 31, 2006, we reported a liability of $4.3 million, and a reduction in Accumulated other comprehensive income in an equal and offsetting amount less ineffectiveness recognized of less than $0.1 million, for the fair values of the August 2007 rate locks.

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At December 31, 2006 and 2005, approximately $14.0 million and $6.5 million, of our gas stored underground, which we own and carry as current Gas stored underground, is exposed to commodity price risk. Additionally, as a result of the Western Kentucky storage expansion project, approximately 4.8 Bcf of gas stored underground with a book value of $11.3 million is subject to forward sales agreements which base the ultimate sales price on the price of NYMEX natural gas futures, to be determined in March 2007. Our operating subsidiaries utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas and also for cash received for fuel reimbursement.

The derivatives related to the sale of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The 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 (loss). The deferred gains and losses are recognized in the Consolidated Statements of Income when the hedged anticipated purchases or sales affect earnings.

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 the Consolidated Statements of Income.

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, 2006, the amount of gas loaned out by our subsidiaries was approximately 15.1 Trillion British thermal units (TBtu) and, assuming an average market price during December 2006 of $6.81 per MMBtu, the market value of gas loaned out at December 31, 2006 would have been approximately $102.8 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, 2006, our cash equivalents were invested primarily in money market investments. Due to the short-term nature and type of our investments, a hypothetical 10% 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 affected by the effect of a sudden change in market interest rates on our investment portfolio.

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, 2006 and 2005, 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, 2006. 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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, 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. As discussed in Note 15 to the consolidated financial statements, in 2006, the Partnership adopted the provisions of Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106 and 132(R).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2006, 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 22, 2007 expressed an unqualified opinion on management's assessment of the effectiveness of the Partnership's internal control over financial reporting and an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 22, 2007

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 management's assessment, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting, included at Item 9A, that Boardwalk Pipeline Partners, LP and subsidiaries (the "Partnership") maintained effective internal control over financial reporting as of December 31, 2006, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that Boardwalk Pipeline Partners, LP maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, Boardwalk Pipeline Partners, LP maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 of the Partnership and our report dated February 22, 2007 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 and the adoption of FASB Statement No. 158.

DELOITTE & TOUCHE LLP
Chicago, Illinois
February 22, 2007

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

	December 31,	
ASSETS	**2006**	**2005**
Current Assets:		
Cash and cash equivalents	$ 399,032	$ 65,792
Receivables:		
Trade, net	54,082	59,115
Other	12,759	5,564
Gas Receivables:		
Transportation and exchange	9,115	29,557
Storage	11,704	12,576
Inventories	14,110	15,881
Costs recoverable from customers	11,236	3,560
Gas stored underground	14,001	6,500
Prepaid expenses and other current assets	22,117	7,720
Total current assets	548,156	206,265
Property, Plant and Equipment:		
Natural gas transmission plant	1,997,922	1,772,483
Other natural gas plant	213,926	213,136
	2,211,848	1,985,619
Less—accumulated depreciation and amortization	187,412	118,213
Property, plant and equipment, net	2,024,436	1,867,406
Other Assets:		
Goodwill	163,474	163,474
Gas stored underground	161,537	169,177
Costs recoverable from customers	19,767	43,960
Other	33,929	15,209
Total other assets	378,707	391,820
Total Assets	$ 2,951,299	$ 2,465,491

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED BALANCE SHEETS
(Thousands of Dollars)

	December 31,			
LIABILITIES AND PARTNERS' CAPITAL		**2006**		**2005**
Current Liabilities:				
Payables:				
Trade	$	56,604	$	20,433
Affiliates		3,014		835
Other		14,459		3,681
Gas Payables:				
Transportation and exchange		15,485		14,710
Storage		42,127		27,559
Other accrued taxes		16,082		16,004
Accrued interest		19,376		17,996
Accrued payroll and employee benefits		18,198		29,028
Current note payable		-		42,100
Deferred income		22,147		1,025
Other current liabilities		20,926		28,916
Total current liabilities		228,418		202,287
Long -Term Debt		1,350,920		1,101,290
Other Liabilities and Deferred Credits:				
Pension and postretirement benefits		15,761		32,413
Asset retirement obligation		14,307		14,074
Provision for other asset retirement		39,644		33,212
Other		29,742		93,541
Total other liabilities and deferred credits		99,454		173,240
Commitments and Contingencies				
Partners' Capital:				
Common units - 75,156,122 and 68,256,122 common units issued and outstanding as of December 31, 2006 and 2005		941,792		705,609
Subordinated units - 33,093,878 units issued and outstanding as of December 31, 2006 and 2005		285,543		266,578
General partner		22,060		16,661
Accumulated other comprehensive income (loss), net of tax		23,112		(174)
Total partners' capital		1,272,507		988,674
Total Liabilities and Partners' Capital	$	2,951,299	$	2,465,491

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, 2006	2005	2004
Operating Revenues:			
Gas transportation	$ 508,241	$ 505,148	$ 245,306
Parking and lending	49,163	21,426	8,182
Gas storage	32,396	21,667	7,289
Other	17,842	12,225	2,844
Total operating revenues	607,642	560,466	263,621
Operating Costs and Expenses:			
Operation and maintenance	161,279	174,641	48,336
Administrative and general	97,298	78,752	52,535
Depreciation and amortization	75,771	72,078	33,977
Taxes other than income taxes*	24,175	27,361	19,044
Net (gain) on disposal of operating assets	(4,829)	(7,846)	-
Total operating costs and expenses	353,694	344,986	153,892
Operating income	253,948	215,480	109,729
Other (Income) Deductions:			
Interest expense	62,123	60,067	30,081
Interest income	(4,202)	(1,478)	(352)
Interest income from affiliates, net	(27)	(2,186)	(375)
Miscellaneous other income, net	(1,749)	(1,444)	(783)
Total other (income) deductions	56,145	54,959	28,571
Income before income taxes	197,803	160,521	81,158
Income taxes and charge-in-lieu of income taxes *	253	49,494	32,333
Elimination of cumulative deferred taxes *	-	10,102	-
Net income *	$ 197,550	$ 100,925	$ 48,825

*Results of operations for the year ended December 31, 2005 reflect a change in the tax status associated with Boardwalk Pipeline Partners and Boardwalk Pipelines coincident with the initial public offering. Boardwalk Pipeline Partners 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 and has recorded no charge-in-lieu of income taxes thereafter. Pursuant to the change in tax status, Boardwalk Pipeline Partners 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"). A subsidiary of Boardwalk Pipeline Partners directly incurs 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, 2006	For the Period November 15, 2005 through

				December 31, 2005
Net income	$	197,550	$	35,992
Less general partner's interest in Net income		3,951		720
Limited partners' interest in Net income	$	193,599	$	35,272
Basic and diluted net income per limited partner unit:				
Common and subordinated units	$	1.85	$	0.35
Cash distribution to common and subordinated unitholders and general partner unit equivalents	$	1.32		-
Weighted-average number of limited partners units outstanding:				
Common units		68,977,766		68,256,122
Subordinated units		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,		
	2006	**2005**	**2004**
OPERATING ACTIVITIES:			
Net income	$ 197,550	$ 100,925	$ 48,825
Adjustments to reconcile to cash provided from (used in) operations:			
Depreciation and amortization	75,771	72,078	33,977
Amortization of acquired executory contracts	(3,997)	(9,630)	-
Provision for deferred income taxes	(39)	54,682	43,428
Gain on disposal of operating assets	(4,829)	(7,846)	-
Changes in operating assets and liabilities, net of assets and liabilities acquired:			
Receivables	20,878	(21,147)	(9,777)
Inventories	1,772	(1,699)	(217)
Affiliates	2,180	(824)	(341)
Other current assets	(18,058)	(3,669)	6,320
Accrued and deferred income taxes	85	4,908	(10,996)
Payables and accrued liabilities	31,902	43,788	(9,532)
Other, including changes in noncurrent assets and liabilities	(47,663)	(12,852)	2,729
Net cash provided by operating activities	255,552	218,714	104,416
INVESTING ACTIVITIES:			
Capital expenditures, net	(200,330)	(82,955)	(41,920)
Proceeds from sale of operating assets	3,646	4,725	-
Proceeds from insurance reimbursements and other recoveries	5,928	4,177	-
Advances to affiliates, net	(760)	(28,252)	(32,194)
Investment in Gulf South, net of cash and working capital adjustment receivable	-	-	(1,111,411)
Net cash used in investing activities	(191,516)	(102,305)	(1,185,525)
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	338,307	569,369	575,000
Payment of long-term debt	(90,000)	(575,000)	(17,285)
Distributions and dividends	(136,388)	(131,686)	(30,000)
Capital contribution from parent and general partner	4,176	6,684	550,741
Proceeds from sale of common units, net of related transaction costs	195,209	271,398	-
Net cash provided by (used in) financing activities	269,204	(67,135)	1,078,456
	333,240	49,274	(2,653)

Increase (decrease) in cash and cash equivalents			
Cash and cash equivalents at beginning of period	65,792	16,518	19,171
Cash and cash equivalents at end of period	$ 399,032	$ 65,792	$ 16,518

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

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY AND PARTNERS' CAPITAL

	Paid in Capital	Retained Earnings	Accumulated Other Comp Income (Loss)	Common Units	Subordinated Units	General Partner	Total Partners' Capital
Balance January 1, 2004	$ 520,910	$ 2,451	-	-	-	-	-
Add (deduct):							
Capital contribution	550,741	-	-	-	-	-	-
Net income	-	48,825	-	-	-	-	-
Dividends paid	-	(30,000)	-	-	-	-	-
Balance December 31, 2004	$ 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	-	-	-	-
<u>Boardwalk Pipeline Partners, LP</u>							
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	-	-	(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

41

BOARDWALK PIPELINE PARTNERS, LP

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Thousands of Dollars)

	For the Year Ended December 31, 2006	For the Year Ended December 31, 2005	For the Year Ended December 31, 2004
Net income	$ 197,550	$ 100,925	$ 48,825
Other comprehensive income (loss):			
Gain (loss) on cash flow hedges	19,405	(2,735)	-
Reclassification adjustment transferred to Net income	(10,922)	2,561	-
Total comprehensive income	$ 206,033	$ 100,751	$ 48,825

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, Texas Gas Transmission, LLC (Texas Gas) and Gulf South Pipeline Company, LP (Gulf South) (together, the operating subsidiaries).

In the fourth quarter 2006, the Partnership sold 6,900,000 common units in a follow-on public offering. The follow-on offering resulted in net proceeds of approximately $199.4 million, after deducting underwriting discounts and offering expenses of $9.4 million, and including $4.2 million from the general partner to maintain its 2.0% interest in the Partnership. The proceeds of the equity offering will be used to finance the Partnership's expansion activities discussed in Note 3. The common units sold in the Partnership's initial public offering (IPO) on November 15, 2005, and follow-on offering, totaling 21,900,000 common units, represent approximately 19.8% of the partners' capital which includes 75,156,122 common units, 33,093,878 subordinated units and a 2.0% general partner interest. All of the common and subordinated units, other than the common units sold in the public offerings, are held by Boardwalk Pipelines Holding Corp. (BPHC) a wholly-owned subsidiary of Loews Corporation (Loews). Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 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).

In connection with the consummation of the IPO in November 2005, 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 53,256,122 common units, 33,093,878 subordinated units, representing an 83.5% limited partnership 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.

Net proceeds in the amount of $271.4 million, from the IPO were used to repay the $250.0 million of indebtedness that the Partnership assumed from BPHC in connection with the contribution of its interest in the Partnership, and to provide approximately $21.4 million in additional working capital for the Partnership.

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 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. On December 29, 2004, Boardwalk Pipelines acquired Gulf South (GS-Acquisition). The results and financial position of Gulf South have been included in the consolidated financial statements from the date of the GS-Acquisition.

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 and has recorded no charge-in-lieu of income taxes thereafter. 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. One of the Partnership's subsidiaries directly incurs some income-based state taxes which are presented in Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

GS-Acquisition

The Partnership made an allocation of the purchase price in connection with the GS-Acquisition which was finalized in December 2005. The purchase price was assigned to the assets and liabilities of Gulf South, based on their estimated fair values using management's analyses with consideration of external valuations as reflected in the following table (in thousands):

Current assets	$	71,283
Property, plant and equipment		1,159,251
Other non-current assets		28,319
Current liabilities		(84,273)
Other liabilities and deferred credits		(53,153)
	$	1,121,427

The following unaudited pro forma financial information is presented as if Gulf South had been acquired as of the beginning of 2004. The pro forma amounts include certain adjustments, including depreciation expense based on the allocation of the purchase price to property, plant and equipment (PPE); adjustment of interest expense to reflect the issuance of debt by Gulf South and Boardwalk Pipelines; and the related tax effect of these items (in thousands):

		(unaudited) For the Year Ended December 31, 2004
Operating revenues	$	504,471
Income before income taxes		121,598
Net income		73,525

The pro forma information does not necessarily reflect the actual results that would have occurred had the companies been combined during the period presented, nor is it necessarily indicative of future results of operations.

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, Texas Gas, and Gulf South 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, workers' compensation insurance, pensions and other post retirement and employment 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 13,400 miles of pipelines and integrated storage fields.

Cash and Cash Equivalents

Cash equivalents are stated at cost plus accrued interest, which approximates fair value. Cash equivalents are highly liquid investments with an original maturity of three months or less. The Partnership had no restricted cash at December 31, 2006 and 2005.

Cash Management

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.

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 storage (NNS) and parking and lending (PAL) services. Certain of these volumes are necessary to provide 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 services and balancing activity. Gas stored underground includes natural gas volumes owned by the pipelines, reduced by certain operational encroachments upon that gas. Current gas stored underground represents retained fuel and excess working gas at Gulf South 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 making a cash payment or physically delivering gas.

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 transportation and exchange imbalances, which are primarily repaid or recovered in cash or through the receipt or delivery of gas in the future. Settlement of imbalances requires agreement between the pipelines and shippers or operators as to allocations of volumes to specific transportation contracts and timing of delivery of gas based on operational conditions. For

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

Gas receivables and payables reflect amounts of customer-owned gas at the Texas Gas facilities. 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 gas payables amount reflected in Gas Payables on the Consolidated Balance Sheets is valued at a historical cost of gas of $45.7 million and $33.6 million at December 31, 2006 and 2005. 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, 2006 and 2005, Gulf South held 61.0 trillion British thermal units (TBtu) and 32.8 TBtu of gas owned by shippers, and had loaned 0.2 TBtu of gas to shippers as of December 31, 2005. No gas was loaned by Gulf South to shippers as of December 31, 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 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 (loss). The deferred gains and losses are recognized in the Consolidated Statements of Income when the hedged anticipated transactions affect earnings. Note 8 contains more information regarding the Partnership's derivative financial instruments.

Property, Plant and Equipment

PPE is recorded at its original cost of construction or fair value of assets acquired. Construction costs and expenditures for major renewals and improvements, which extend the lives of the respective assets, are capitalized.

Texas Gas's depreciation 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. 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.

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.

Goodwill

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. The impairment test for goodwill is performed annually at December 31. No impairment was recorded during 2006, 2005 or 2004.

Advances to Affiliates

The Partnership makes advances to and receives advances from its subsidiaries and BPHC. These advances are represented by demand notes. Advances 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.

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. 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. Gulf South does not apply SFAS No. 71. Certain services provided by Gulf South are market-based and competition in Gulf South's market area has often resulted in discounts from the maximum allowable cost-based rate such that SFAS No. 71 has not been appropriate. Therefore, Gulf South does not record any regulatory assets or liabilities.

The Partnership monitors the regulatory and competitive environment in which it operates to determine that the regulatory assets recorded at Texas Gas 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 which would no longer be deemed refundable.

Acquired Executory Contracts

As a result of the GS-Acquisition, the Partnership recorded certain shipper contracts at fair value. The below market valuation balance of $1.3 million as of December 31, 2006, included $1.1 million as a component of Other current liabilities and $0.2 million as a component of Other Liabilities and Deferred Credits. 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 ending in early 2008. Amortization for 2006 and 2005 was $4.0 million and $9.5 million. Amortization for 2007 and 2008 is expected to be $1.1 million and $0.2 million.

Asset Retirement Obligations

SFAS No. 143, *Accounting for Asset Retirement Obligations*, addresses accounting and reporting for existing legal obligations associated with the future retirement of long-lived assets. SFAS No. 143 requires entities to record the fair value of a liability for an asset retirement obligation (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.

Unit-Based Compensation

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment,* which establishes accounting standards for transactions in which an entity exchanges its equity instruments for goods or services, primarily focusing on transactions where an entity obtains employee services. SFAS No. 123(R) requires a public entity to measure the cost of employee services received in exchange for an award of equity instruments, based on the grant-date fair value of the award and to recognize it as compensation expense over the period the employee is required to provide service in exchange for the award, usually the vesting period. The Partnership adopted SFAS No. 123(R) during 2005 due to the adoption of its Long-Term Incentive Plan in 2005. There were no previous unit-based compensation plans.

In February 2006, FASB Staff Position (FSP) FAS 123(R)-4 amended SFAS No. 123(R) to require evaluation of the probability of occurrence of a contingent cash settlement event in determining whether the underlying options or similar instruments issued as employee compensation should be classified as liabilities or equity. The Partnership applied the principles of FSP FAS 123(R)-4 in conjunction with the adoption of SFAS No. 123(R) which had no material impact on its financial condition, results of operations, or cash flows. 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 FERC 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 transported volumes. Revenues from storage services are recognized over the term of the contracts. When an entity is involved in a rate case, certain revenues collected may be subject to possible refunds pending the final outcome of the proceedings. An estimate of a potential rate refund liability is made considering its own and third-party regulatory proceedings, advice of counsel and estimated total exposure. Texas Gas filed a rate case in 2005 which was settled in the second quarter 2006. Note 3 contains more information regarding the Texas Gas rate case settlement.

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, 2006 and 2005 were $73.2 million and $86.7 million. Since only three days of Gulf South's 2004 results were included in the Partnership's Consolidated Statements of Income, the amount of retained fuel included in transportation revenues was negligible.

The Partnership had deferred revenue of $22.4 million at December 31, 2006, related to PAL services to be provided mainly in 2007 and a minor amount in early 2008. At December 31, 2005, the Partnership had deferred revenue of $1.0 million. Revenue deferred at year end will be recognized when the services are provided.

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.

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)

AFUDC represents the cost of funds, including equity, applicable to the regulated natural gas transmission plant under construction as permitted by FERC regulatory practices. The allowance for borrowed funds used during construction and capitalized interest 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 the allowance for borrowed funds and capitalized interest and the allowance for equity funds used during construction (in millions):

	For the Year Ended December 31,		
	2006	**2005**	**2004**
Allowance for borrowed funds used during construction and capitalized interest	$ 2.3	$ 0.7	$ 0.3
Allowance for equity funds used during construction	1.2	1.4	0.8

Cash Flows from Operating Activities

The Partnership uses the indirect method to report cash flows from operating activities, which requires adjustments to net income to reconcile to net cash flows provided by operating activities.

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. Through December 31, 2006, there have not been any distributions paid based on the incentive distribution rights.

Income Taxes

Boardwalk Pipeline Partners is not a taxable entity for federal income tax purposes. As such, it does not directly pay federal income tax. Boardwalk Pipeline Partners' 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 Boardwalk Pipeline Partners' net assets for financial and income tax purposes cannot be readily determinable as it does not have access to the information about each partner's tax attributes related to Boardwalk Pipeline Partners. One of the Partnership's subsidiaries directly incurs some income-based state taxes which are presented in Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

Reclassifications

Certain reclassifications have been made to the 2005 and 2004 financial statements to conform to the 2006 presentation, primarily related to the presentation of PAL revenues and Interest expense as separate line items on the Consolidated Statements of Income.

Note 3: Commitments and Contingencies

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 Gulf South assets and a smaller portion of the Texas Gas assets are located in the area directly impacted by the hurricanes.

During 2006 and 2005, the Partnership recognized charges of $0.1 million and $12.9 million in the Consolidated Statements of Income for the estimated cost of damage from the hurricanes. In 2006, the Partnership recognized $10.7 million of insurance recoveries associated with Hurricane Katrina, of which $6.0 million was received in the fourth quarter 2006. The total impact of the charges and insurance recoveries was a $10.6 million increase in 2006 earnings and $12.9 million decrease in 2005 earnings. This was recorded as follows (in millions):

	2006	**2005**
Operating Revenues	$ 3.3	$ (2.0)
Operating Costs and Expenses	7.3	(10.9)
Increase/(Decrease) in Net Income	$ 10.6	$ (12.9)

In addition, the Partnership is pursuing recovery of insurance proceeds related to Hurricane Rita, but no amount has been deemed probable of recovery. The combined remaining liability for both hurricanes was $1.0 million and $5.6 million as of December 31, 2006 and 2005.

Legal Proceedings

Hurricane Katrina - Related Class Actions

Gulf South, along with at least eight other interstate pipelines and major natural gas producers, has been named in three Hurricane Katrina-related class action lawsuits filed in the United States District Court for the Eastern District of Louisiana (District Court). The lawsuits allege that the dredging of canals caused damage to the marshes and that undamaged marshes would have prevented all, or almost all, of the loss of life and destruction of property caused by Hurricane Katrina. The District Court has dismissed all three cases.

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 the early stages of discovery. Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. Gulf South has settled several 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. From the date of acquisition of Gulf South on December 29, 2004 through November 2006, Gulf South incurred $7.0 million for remediation costs, root cause investigation, and legal fees. At December 31, 2006, there was no remaining liability balance. At December 31, 2005, the Partnership had a liability balance of $1.1 million in Other current liabilities, on the Consolidated Balance Sheets pertaining to the incident. 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 2006, Gulf South received $0.8 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 including, among others, these previously disclosed matters:

· Litigation filed by Jack Grynberg alleging that approximately 300 energy companies, including Texas Gas, had violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. In October 2006, the United States District Judge issued an order dismissing these claims, including the claims against Texas Gas, for lack of subject matter jurisdiction. That order is, however, subject to appeal; and

· A claim by certain parties for back rental associated with their alleged ownership of a partial mineral interest in a tract of land in a gas storage field owned by Texas Gas. In December 2003, a lawsuit was filed against Texas Gas in Muhlenberg County, Kentucky, seeking unspecified damages related to this claim. In April 2005, in the first phase of this lawsuit, the court entered an order granting partial summary judgment against Texas Gas related to the vesting of legal title to the disputed acreage. However, in January 2007, the court entered an order concluding that the plaintiff was estopped by his actions from pursuing his claims and dismissed the lawsuit. The plaintiff has filed a motion to vacate the order dismissing the lawsuit and is expected to appeal.

Williams continues to defend these actions on behalf of the Partnership and Texas Gas. Williams has retained responsibility for these claims, therefore they 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

Expansion Projects

Carthage to Keatchie Loop. The Partnership has constructed a 20.5 mile segment of 42-inch pipeline from Carthage, Texas to Keatchie, Louisiana which was placed in service in December 2006. The current capacity of this loop is 120 MMcf per day.

East Texas to Mississippi Expansion. The Partnership is pursuing a pipeline expansion project consisting of 242 miles of 42-inch pipeline from DeSoto Parish in western Louisiana to near Harrisville, Mississippi and approximately 110,000 horsepower of new compression. The expansion would add approximately 1.7 Bcf per day of new transmission capacity to the Partnership's Gulf South pipeline system. The natural gas to be transported on this expansion will originate primarily from the Barnett Shale and Bossier Sands producing regions of East Texas. The expansion will transport natural gas to new interstate pipeline interconnects in the Perryville, Louisiana area and existing pipeline interconnects with other pipelines east of the Mississippi River. This project is supported by binding precedent agreements with customers who have contracted, on a long-term basis (with a weighted average term of approximately 7 years), for 1.3 Bcf per day from Carthage, Texas with an option for an additional 100 MMcf per day. On September 1, 2006, the Partnership filed a certificate application relating to this project with the FERC. The Partnership expects this project to be in service during the fall of 2007.

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 a new subsidiary, Gulf Crossing Pipeline Company LLC (Gulf Crossing), and will consist of approximately 355 miles of 42-inch pipeline having capacity of up to approximately 1.6 Bcf per day. Additionally, Gulf Crossing will enter into: (i) a lease for at least 1.1 Bcf per day of capacity on the Partnership's Gulf South pipeline system (including on the Southeast Expansion and 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; and (ii) a lease with a third-party intrastate pipeline which will bring certain gas supplies to the Partnership's system. This project is supported by binding agreements with customers who have contracted for 1.1 Bcf per day of capacity under firm contracts having terms of 5 to 10 years (with a weighted average term of approximately 9.8 years), and options with certain of these customers for an additional 350 MMcf per day of capacity. The Partnership anticipates making the required filings with the FERC by July 2007 and for the project to be in service during the fourth quarter of 2008. The Partnership is in negotiations with one of the foundation shippers supporting this project concerning the purchase of 49.0% of the equity of Gulf Crossing.

Southeast Expansion. The Partnership is pursuing a pipeline expansion extending its Gulf South pipeline system from near Harrisville, Mississippi to an interconnect with Transco in Choctaw County, Alabama which will enhance its ability to deliver gas to the Northeast through other pipeline interconnects. This expansion will consist of approximately 112 miles of 42-inch pipeline having initial capacity of approximately 1.2 Bcf per day, expandable to as much as 2.0 Bcf per day to accommodate volumes expected to come from the Gulf Crossing leased capacity discussed above. In addition, Gulf South has executed a lease with Destin Pipeline Company to access markets in Florida. This project is supported by binding agreements with customers who have contracted for 660 MMcf per day of capacity under firm contracts having terms of 5 to 10 years (with a weighted-average term of 9.2 years), as well as the capacity leased to Gulf Crossing discussed above. The certificate filing was made with the FERC in December 2006 and the project is anticipated to be in service during first quarter 2008.

Fayetteville Shale. The Partnership is pursuing the construction of two laterals connected to the Texas Gas pipeline system to transport gas from the Fayetteville Shale area in Arkansas to markets directly and indirectly served by Texas Gas. The Fayetteville Lateral, consisting of approximately 165 miles of 36-inch pipeline, is anticipated to have an initial design capacity of 800 MMcf per day and a maximum design capacity of 1.1 Bcf per day. This lateral will originate in Conway County, Arkansas and proceed southeast through the Bald Knob, Arkansas area to an interconnect with Texas Gas's mainline in Coahoma County, Mississippi. The Greenville Lateral, consisting of approximately 95 miles of pipeline with an initial design capacity of 750 MMcf per day, will originate at Texas Gas's mainline near Greenville, Mississippi and proceed east to the Kosciusko, Mississippi area. The Greenville Lateral will allow customers to access additional markets, primarily in the Midwest, Northeast and Southeast, including the Henry Hub. Construction of both laterals is supported by a binding precedent agreement with Southwestern Energy Services Company, a wholly-owned subsidiary of Southwestern Energy Company. In December 2006, the FERC granted Texas Gas's request to initiate the pre-filing process for this project and the Partnership anticipates making the required certificate filings with the FERC in June 2007. The Partnership expects the project to be in service during the first quarter 2009.

The total cost of the pipeline expansion projects discussed above is expected to be approximately $3.3 billion (before taking into account equity that would be contributed by the purchaser of a 49.0% interest in Gulf Crossing Pipeline referred to above). The Partnership is constantly seeking to optimize these projects to reduce the overall cost. However the actual cost to complete these projects may exceed the current estimate as a result of, among other things, higher labor and materials costs due to the large number of pipeline projects under way throughout the industry or the need to expand pipeline capacity if the Partnership contracts for additional volumes. For a further discussion of the risks associated with these projects, see the section on Risk Factors in Item 1A of this Report.

Western Kentucky Storage Expansion. In December 2006, the FERC issued a certificate approving Texas Gas's Phase II storage expansion project which will expand the working gas capacity in its 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 for the full additional capacity at Texas Gas's maximum applicable rate. The Partnership expects this project to cost approximately $40.7 million and to be in service by November 2007. In December 2006, Texas Gas commenced an open season related to a potential third expansion of its storage facilities. Texas Gas has signed one precedent agreement for 2.0 Bcf of capacity. The ultimate size of the Phase III storage expansion will be determined, in part, by the open season. The Phase III storage expansion is subject to the FERC approvals, including potential market-based rate authority for the additional new storage capacity being created. Phase I of this project which expanded working gas capacity by approximately 8.0 Bcf was completed and in service in November 2005.

Magnolia Storage Facility. The Partnership is currently developing an additional storage cavern near Napoleonville, Louisiana. During mining operations, certain issues have arisen causing the mining of the cavern to be suspended. We are continuing to conduct operational integrity tests on the caverns. The tests are on-going but have been delayed due to lack of equipment availability needed to complete the testing. If the test results are favorable, we expect the storage facilities to be in service perhaps as early as 2008 with working gas capacity of 2.0 Bcf, reduced from 6.0 Bcf as originally designed. If the test results are not favorable, the Partnership will consider the options it has available, including developing a new cavern, or the sale or abandonment of the project. The total book value of the project at December 31, 2006 was $42.7 million. The Partnership tested the investment in Magnolia for recoverability in accordance with the requirements of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*. No impairment loss has been recognized as a result of the recoverability tests.

Texas Gas Rate Case

Texas Gas filed a rate case with the FERC on April 29, 2005, and implemented the new rates on November 1, 2005, subject to refund. As of December 31, 2005, an estimated refund liability of approximately $5.0 million related to the rate case was recorded on the Consolidated Balance Sheets. The rate case was settled in the second quarter 2006 and the refund liability was reduced to zero by the amount of cash refunds paid to customers on June 30, 2006, consisting of $6.4 million in principal and $0.2 million of interest. At December 31, 2006, there was no liability for any open rate case recorded on the Consolidated Balance Sheets. In accordance with the terms of the settlement, Texas Gas has no obligation to file a new rate case and is prohibited from placing new rates into effect prior to November 1, 2010. Currently, neither Texas Gas nor Gulf South is involved in an open general rate case.

Pipeline Integrity

The Office of Pipeline Safety (OPS) has issued a final rule that requires natural gas pipeline operators to develop integrity management programs. Pursuant to the rule, pipelines were required to identify high consequence areas (HCAs) on their systems and develop a written integrity management program providing for a baseline assessment and periodic reassessments to be completed within specified timeframes. The Partnership has complied with these requirements. Its estimated costs to comply with the rule during the initial ten-year baseline period ending in 2012 range from $100.0 to $120.0 million. As of December 31, 2006, the Partnership has invested approximately $22.3 million to develop and implement integrity management programs 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.

On June 30, 2005, the FERC issued an order addressing the accounting treatment for the costs pipeline operators will incur in implementing all aspects of pipeline integrity management programs which are required by the OPS. The FERC's accounting guidance became effective prospectively, beginning with integrity management costs incurred on or after January 1, 2006. Amounts capitalized in periods prior to January 1, 2006, were permitted to remain as recorded. The Partnership applied the accounting guidance order on January 1, 2006. There were no changes to the Partnership's accounting policy for the pipeline integrity management programs as a result of the application of this guidance.

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, 2006 and 2005, the Partnership had an accrued liability of approximately $18.4 million and $20.0 million related to environmental remediation.

Beginning in 2004, as part of the Partnership's proactive approach and continued implementation of environmental remediation efforts, Texas Gas entered into agreements, or met with various state agencies, to address remediation issues primarily on a voluntary basis. As of December 31, 2006 and 2005, Texas Gas had an accrued liability of $2.8 million, $1.0 million of which was presented in Current Liabilities, and $3.5 million, for estimated remaining probable costs associated with environmental assessment and remediation, primarily for remediation associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury. This accrual represents management's estimate of the undiscounted future obligation based on evaluations and discussions with counsel and independent consultants and the current facts and circumstances related to these matters. The assumptions are based on a substantial number of existing assessments and completed remedial activities by third-party consultants, including a Texas Gas system-wide assessment and/or cleanup of polychlorinated biphenyls, petroleum hydrocarbons, mercury and asbestos abatement. Texas Gas is continuing to conduct environmental assessments and is implementing a variety of remedial measures that may result in a change in the total estimated costs. These costs are expected to occur over approximately the next five years.

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, Marshall County, Kentucky. The Partnership is unable to estimate with any certainty at this time any potential liability it may incur related to this notice, however, the Partnership does not expect this to have a material effect on its financial condition.

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% 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 advantages of the settlement agreement are:

(1) the EPA will not pursue any further action against Texas Gas for EPA costs related to the site no matter how much the planned remedial action ultimately may cost, and

(2) the Super Fund law provides protection from "contribution" suits for parties that settle, i.e. suits from other potentially responsible parties that perform or finance cleanup at the site.

Texas Gas has agreed to the settlement. The EPA held a 30-day public comment period regarding Texas Gas's settlement. The EPA will notify Texas Gas when the settlement is effective and payment of the $0.1 million will be due within thirty days of the effective date.

An analysis of the environmental contamination and related remediation costs at sites owned and/or operated by Gulf South was conducted by the Partnership in conjunction with a third-party consultant. As a result, Gulf South has recorded an environmental accrual comprised of estimated future costs associated with identifying and remediating contamination from hydrocarbons, mercury and polychlorinated biphenyls; enhancement of groundwater protection measures; and other costs.

The non-current portion of this accrual was $13.1 million and $14.0 million as of December 31, 2006 and 2005, and the current portion of this accrual was $2.5 million at both December 31, 2006 and 2005. The accruals recorded by Gulf South were based upon analysis of the findings of the environmental consultant, including the assumptions underlying such findings. Those assumptions reflect management's best estimate of the probable remediation costs based on the known levels of contamination, the historical experience of individual pipelines and the expertise of the environmental consultant in remediating such contamination. The actual cost of remediation could be impacted by the discovery of additional contamination, including for example, groundwater contamination, at one or more sites as a result of its on-going due diligence review. The Partnership could uncover additional information during the course of remediating a particular site, as well as by determinations or requests, if any, made by regulatory authorities relating to the remediation of any particular site.

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 operates two facilities in areas affected by non-attainment requirements for the current ozone standard (eight-hour standard). As of December 31, 2006, the Partnership had incurred costs of approximately $14.0 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 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 addition, the EPA promulgated new rules regarding hazardous air pollutants in 2004, which will impose additional controls at three facilities at an estimated cost of $1.7 million. The effective compliance date for the hazardous air pollutants regulations is 2007. The Partnership anticipates continued installation of associated controls to meet these new regulations in 2007. In addition, three of Gulf South's facilities located in Texas are required to make changes to meet additional requirements imposed by the state of Texas in regards to the CAA. The effective compliance date for such additional Texas requirements is March 1, 2007. Gulf South expects to spend approximately $0.4 million to meet these requirements. 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 covering storage facilities, offices and equipment. The lease for Gulf South's current office space expires in May 2007 and, accordingly, Gulf South signed a new ten-year lease for approximately 74,000 square feet of office space in a new location in Houston, Texas. Payments due under the lease are approximately $1.6 million per year for the first five years and $1.8 million per year thereafter. Gulf South will begin moving into the new headquarters in April 2007. Total lease expenses during 2006 and 2005 were approximately $4.7 million and $4.2 million. Amounts for 2004 were immaterial. The following table summarizes minimum future commitments related to these items at December 31, 2006 (in millions):

2007	$ 5.9
2008	5.6
2009	4.5
2010	4.2
2011	2.0
Thereafter	12.6
Total	$ 34.8

Commitments for Construction

The Partnership incurred $200.3 million of capital expenditures in 2006, net of amounts received for salvage and accrued amounts. The Partnership's future capital commitments as of December 31, 2006, for contracts already authorized are expected to approximate the following amounts (in millions):

Less than 1 year	$ 403.8
1-3 years	5.2
4-5 years	0.1
More than 5 years	-
Total	$ 409.1

54

Note 4: Property, Plant and Equipment

In 2006, Texas Gas 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.

In June 2006, Gulf South 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 will be used to offset the costs of rebuilding certain offshore facilities. The total cost of the new facilities is not expected to exceed $8.0 million.

The following table presents the Partnership's PPE as of December 31, 2006 and 2005 (in thousands):

Category	**2006 Class Amount**	**Weighted-Average Useful Lives (Years)**	**2005 Class Amount**	**Weighted-Average Useful Lives (Years)**
Depreciable plant:				
Intangible	$ 18,901	9	$ 10,776	30
Gathering	90,787	19	88,852	19
Storage	163,323	48	155,717	46
Transmission	1,601,064	45	1,484,901	42
General	63,698	16	64,548	19
Total utility depreciable plant	1,937,733	43	1,804,794	41
Non-depreciable:				
Land	9,386		9,470	
Storage	85,392		85,393	
Other	179,297		85,962	
Total other	274,075		180,825	
Total PPE	2,211,848		1,985,619	
Less: accumulated depreciation	187,412		118,213	
Total PPE, net	$ 2,024,436		$ 1,867,406	

The non-transmission assets have weighted-average useful lives of 32 years as of December 31, 2006 and 2005. The gross depreciable non-transmission asset value was $336.7 million and $319.9 million as of December 31, 2006 and 2005. The non-depreciable assets and work in progress of $274.1 million and $180.8 million as of December 31, 2006 and 2005, were not included in the calculation of the weighted-average useful lives. The Partnership's depreciation and amortization expense for the years ended December 31, 2006, 2005, and 2004 was $75.8 million, $72.1 million and $34.0 million.

Note 5: Asset Retirement Obligations

The Partnership has identified and recorded legal obligations associated with the abandonment of offshore pipeline laterals, the abandonment of certain onshore facilities and 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):

	2006	2005
Balance at beginning of year	$ 14,074	$ 3,254
Liabilities recorded	(366)	10,593
Liabilities settled	-	(417)
Accretion expense	599	644
Balance at end of year	$ 14,307	$ 14,074

In March 2005, FASB issued Interpretation No. 47, *Accounting for Conditional AROs,* which 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 Texas Gas's 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 estimated useful life was obtained from a study by the original architects performed in 1995, and confirmed by Natural Resource Group in 2003, indicating 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.

Texas Gas's depreciation rates for utility plant are approved by the FERC. The approved depreciation rates 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 $39.6 million and $33.2 million as of December 31, 2006 and 2005, 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, 2006 and 2005, 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 Texas Gas's embedded cost of debt financing utilized in its 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, 2006 and 2005 (in thousands):

	2006	2005
Regulatory Assets:		
Pension	$ 7,820	$ 3,841
Tax effect of AFUDC equity	6,794	7,236
Unamortized debt expense and premium on reacquired debt	11,703	12,701
Postretirement benefits other than pension	10,569	33,156
Fuel tracker	5,783	2,005
Imbalances/storage valuation tracker	37	1,282
Total regulatory assets	$ 42,706	$ 60,221
Regulatory Liabilities:		
Provision for asset retirement	$ 39,644	$ 33,212
Unamortized discount on long-term debt	(1,851)	(2,024)
Total regulatory liabilities	$ 37,793	$ 31,188

Note 7: Financing

Senior Unsecured Debt

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 notes will be redeemable, in whole or in part, at the Partnerships' option at any time, at a redemption price equal to the greater of 100% of the principal amount of the notes to be redeemed or a "make whole" redemption price based on the remaining scheduled payments of principal and interest discounted at a Treasury rate plus 20 basis points, plus accrued and unpaid interest, if any, to the date of redemption. If certain events of default occur, either the trustee or the holders of not less than 25 percent in principal amount of the then outstanding notes may declare the entire principal of all of the notes and interest accrued thereon to be due and payable immediately. If an event of default due to certain events of bankruptcy, insolvency and reorganization of the Partnership or any significant subsidiary shall have occurred and be continuing, the entire principal of all of the notes and interest accrued thereon will become immediately due and payable without any declaration of acceleration or other act on the part of the trustee or any holders.

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

	December 31,	
	2006	**2005**
Boardwalk Pipelines		
5.88% Notes due 2016	$ 250,000	-
5.20% Notes due 2018	185,000	$ 185,000
5.50% Notes due 2017	300,000	300,000
Texas Gas		
7.25% Debentures due 2027	100,000	100,000
4.60% Notes due 2015	250,000	250,000
Gulf South		
5.05% Notes due 2015	275,000	275,000
	1,360,000	1,110,000
Unamortized debt discount	(9,080)	(8,710)
Total long-term debt	$ 1,350,920	$ 1,101,290

As of December 31, 2006 and 2005, the weighted-average interest rate of the Partnership's long-term debt was 5.40% and 5.29%.

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, 2006, Boardwalk Pipelines and the operating subsidiaries were in compliance with their debt covenants.

In December 2004, Boardwalk Pipelines borrowed $575.0 million as an interim term loan in connection with its acquisition of Gulf South. In January 2005, Boardwalk Pipelines issued $300.0 million principal amount of 5.50% notes due 2017 and Gulf South issued $275.0 million principal amount of 5.05% notes due 2015. The proceeds from these notes, shown as Proceeds from long-term debt, net of issuance costs in the Consolidated Statements of Cash Flows together with available cash, were used to repay the interim loan. In March 2004, Texas Gas repaid $17.3 million representing the balance of its 8.625% notes upon final maturity with available cash.

Revolving Credit Facility

The Partnership maintains a $400.0 million revolving credit facility, under which Boardwalk Pipelines, Texas Gas and Gulf South 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. As of December 31, 2006, the Partnership was in compliance with all the covenant requirements under the credit agreement. During 2006, Gulf South had borrowed and repaid $90.0 million under this credit facility. The interest rates on the borrowings were 5.55% to 5.73%. As of December 31, 2006, no funds were drawn under the facility. The revolving credit facility has a maturity date of June 29, 2011.

In connection with the IPO, Boardwalk Pipelines borrowed approximately $42.1 million against the original credit facility to reimburse BPHC for capital expenditures it incurred in connection with the acquisition of Gulf South, which was subsequently paid off in February 2006. Interest on the credit facility was accrued at the 3-month LIBOR rate plus applicable margin (4.68%).

Note 8: Derivatives

Boardwalk Pipelines entered into a Treasury rate lock October 5, 2006 for a notional amount of $250.0 million of principal to hedge the risk attributable to changes in the risk-free component of forward 10-year interest rates through the expected date of issuance of $250.0 million of senior unsecured notes. The reference rate on the Treasury rate lock was 4.60%. The rate lock was settled at the time of the closing of the debt offering in November 2006. The Partnership received $0.9 million from the counterparty as a result of the settlement of the instrument. The Treasury rate lock was designated as a cash flow hedge in accordance with SFAS No. 133. Accordingly, the $0.9 million settlement amount was recorded as a component of Accumulated other comprehensive income (loss) and will be recognized in income as a reduction to interest expense on a straight-line basis over the 10-year term of the 5.88% senior notes.

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 are 5.00% and 4.96%. Under the terms of the rate locks, the counterparties would pay the Partnership settlement amounts if the 10-year Treasury rate is greater than the reference rates on August 1, 2007. Conversely, the Partnership would pay the counterparties settlement amounts if the 10-year Treasury rate is less than the reference rates. The Treasury rate locks were designated as cash flow hedges in accordance with SFAS No. 133. As of December 31, 2006, the Partnership reported a liability of $4.3 million, and a reduction in Accumulated other comprehensive income (loss) in an equal and offsetting amount less ineffectiveness recognized in 2006 of less than $0.1 million, for the fair values of the August 2007 rate locks.

Certain volumes of gas stored underground are available for sale and subject to commodity price risk. At December 31, 2006 and 2005, approximately $14.0 million and $6.5 million, of Gulf South's gas stored underground, which the Partnership owns and carries as current Gas stored underground, is exposed to commodity price risk. Gulf South utilizes derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas. As a result of the Western Kentucky storage expansion project, approximately 4.8 Bcf of gas stored underground with a book value of $11.3 million at Texas Gas is subject to forward sales agreements which base the ultimate sales price, to be determined in March 2007, on the price of New York Mercantile Exchange (NYMEX) natural gas futures. Texas Gas has entered into derivatives to hedge the price exposure related to these agreements.

The derivatives related to the sale of natural gas and cash for fuel reimbursement generally qualify for cash flow hedge accounting under SFAS No. 133 and are designated as such. The 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 (loss). The deferred gains and losses are recognized in the Consolidated Statements of Income when the hedged anticipated purchases or sales 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 the the Western Kentucky storage expansion project, any gains and losses on the related derivatives would be recognized in Net (gain) on disposal of operating assets.

The fair values of derivatives existing as of December 31, 2006 and 2005 were included in the following captions in the Consolidated Balance Sheets (in millions):

	December 31, 2006	December 31, 2005
Prepaid expenses and other current assets	$ 13.7	$ 0.6
Other current liabilities	5.1	0.8
Accumulated other comprehensive income (loss)	8.5	(0.2)

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 the Consolidated Statements of Income. Ineffectiveness of $0.5 million was recorded during the twelve month period ended December 31, 2006. No ineffectiveness was recorded during the comparable 2005 and 2004 periods. No cash flow hedges were discontinued during the twelve month periods ended December 31, 2006 and 2005.

During 2007 the Partnership expects to reclassify approximately $11.6 million of unrealized gains included in Accumulated other comprehensive income (loss) at December 31, 2006 into earnings.

Derivatives related to the value of company-owned storage capacity and the purchase of operational gas for the East Texas and Mississippi pipeline expansion project were not designated as hedges in accordance with SFAS No. 133. The changes in the values of the derivatives were recognized currently in earnings. In 2006, the Partnership recognized income of $0.7 million in Gas storage revenues and $0.5 million in Miscellaneous other income, net related to the change in fair values associated with the derivatives.

Note 9: Employee Benefits

Retirement Plans

Substantially all of Texas Gas's current employees are covered under a non-contributory, qualified defined-benefit retirement plan. Additionally, 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 (IRC). Texas Gas uses a measurement date of December 31 for its retirement plans. Effective in November 2006, the defined benefit retirement plan was closed to new participants and new employees will be provided benefits under a defined contribution money purchase plan.

Texas Gas has not been required to fund the qualified retirement plan since 1986. As a result of the rate case settlement in 2006, Texas Gas is required to fund the amount of its 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 Texas Gas’s retirement plan including approximately $11.4 million additional funding that the Partnership elected to provide to immediately improve the funded status of the plan. Due to the additional funding, the Partnership does not expect to fund any amount to the Texas Gas retirement plan in 2007. Through December 31, 2006, no funding has been provided for the SRP 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. The Partnership 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 made an immaterial amount of contributions to this plan in 2006, $3.9 million in 2005 and $4.9 million in 2004. Due to plan changes regarding benefits available to current and future retirees described below, the plan is currently in an overfunded status and, therefore, the Partnership does not expect to make any contributions to the Texas Gas PBOP plan in 2007.

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 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. Retirements under the program were generally effective January 1, 2007. Approximately 100 of the eligible employees elected to participate in the program.

As a result of the ERIP, the Partnership recognized a special termination benefit of approximately $6.0 million for pension and $0.9 million for PBOP in 2006. In accordance with the regulatory treatment for Texas Gas's benefits expense, $2.6 million of the special termination benefit for pension and $0.9 million for PBOP was recognized in Administrative and general expense and the remaining $3.4 million of the special termination benefit for pensions was deferred as a regulatory asset.

Initial Application of SFAS No. 158

The Partnership began applying the provisions of SFAS No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans,* for the year ended December 31, 2006. The following tables are presented in accordance with SFAS No. 158. Note 15 contains more information regarding the initial application of SFAS No. 158.

Funded Status

The following table presents the funded status and the amounts not yet recognized as components of net periodic pension cost for both the retirement plans and PBOP at December 31, 2006 and 2005 (in thousands):

	Retirement Plans For the Year Ended December 31,		**PBOP For the Year Ended December 31,**	
	2006	**2005**	**2006**	**2005**
Funded status:				
Projected benefit obligation	$ 136,886	$ 116,931	-	-
APBO	-	-	$ 65,341	$ 134,188
Plan assets at fair value	121,125	96,194	80,218	79,463
Funded status	(15,761)	(20,737)	14,877	(54,725)
Unrecognized net actuarial loss	-	15,691	-	20,412
Net amount recognized	$ (15,761)	$ (5,046)	$ 14,877	$ (34,313)
Items not yet recognized as components of net periodic pension cost:				
Prior service cost	$ 73	-	$ (70,744)	-
Net actuarial loss (gain)	17,967	-	22,316	-
Total	$ 18,040	-		-

$
(48,428)

61

Projected Benefit Obligation

The projected benefit obligation and fair value of assets of the retirement plans and PBOP at December 31, 2006 and 2005 were as follows (in thousands):

	Retirement Plans For the Year Ended December 31,		PBOP For the Year Ended December 31,	
	2006	**2005**	**2006**	**2005**
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 116,931	$ 104,412	$ 134,188	$ 125,599
Service cost	4,432	4,067	1,319	2,076
Interest cost	6,695	6,283	5,147	7,222
Plan participants' contributions	-	-	1,509	1,328
Actuarial loss	6,326	6,214	4,902	5,379
Benefits paid	(3,576)	(4,045)	(7,633)	(7,416)
Retirement / PBOP plan amendment	73	-	(75,271)	-
Special termination benefits (ERIP)	6,005	-	884	-
Retiree drug subsidy	-	-	296	-
Benefit obligation at end of period	$ 136,886	$ 116,931	$ 65,341	$ 134,188
Change in plan assets:				
Fair value of plan assets at beginning of period	$ 96,193	$ 93,056	$ 79,462	$ 76,499
Actual return on plan assets	10,468	7,131	6,539	5,164
Benefits paid	(3,576)	(4,045)	(7,633)	(7,416)
Company contributions	18,040	52	341	3,888
Plan participants' contributions	-	-	1,509	1,328
Fair value of plan assets at end of period	$ 121,125	$ 96,194	$ 80,218	$ 79,463

The Partnership does not anticipate that any plan assets will be returned to the Partnership during 2007. At December 31, 2006 and 2005, the following aggregate information relates only to the underfunded retirement plan (in thousands):

	For the Year Ended December 31, 2006	2005
Projected benefit obligation	$ 136,886	$ 116,931
Accumulated benefit obligation	118,147	94,935
Fair value of plan assets	121,125	96,194

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, 2006, 2005 and 2004 were the following (in thousands):

Retirement Plans	PBOP

	For the Year Ended December 31,			For the Year Ended December 31,		
	2006	2005	2004	2006	2005	2004
Service cost	$ 4,432	$ 4,067	$ 3,531	$ 1,319	$ 2,076	$ 2,095
Interest cost	6,695	6,283	5,636	5,147	7,222	5,912
Expected return on plan assets	(7,131)	(6,859)	(6,644)	(4,653)	(4,632)	(5,252)
Amortization of prior service credit	-	-	-	(4,527)	-	-
Amortization of unrecognized net loss (gain)	713	300	(20)	1,112	362	(66)
Special termination benefit (ERIP)	6,005	-	-	884	-	-
Regulatory asset decrease (increase)	(3,979)	(3,713)	(2,455)	7,337	-	-
Net periodic pension expense	$ 6,735	$ 78	$ 48	$ 6,619	$ 5,028	$ 2,689

The decrease in the regulatory asset for PBOP is due to the amortization of costs incurred in prior years.

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
2007	$ 35,674	$ 5,524
2008	3,808	5,393
2009	4,286	5,223
2010	6,280	5,012
2011	7,052	4,962
2012-2017	60,973	23,055

Weighted -Average Assumptions

The Partnership's weighted-average asset allocations at December 31, 2006 and 2005 for both the qualified retirement plan and PBOP trusts by category were as follows:

	Retirement Plan		PBOP	
	December 31, 2006	December 31, 2005	December 31, 2006	December 31, 2005
Debt securities	37.1%	62.5%	-	-
Equity securities	27.4%	30.9%	-	-
Limited partnership	12.1%	6.4%	-	-
Other	23.4%	0.2%	-	-
Fixed income	-	-	46.3%	45.2%
Cash and other	-	-	53.7%	54.8%
Total	100.0%	100.00%	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 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, 2006 and 2005 were the following:

	Retirement Plans		PBOP	
	December 31, 2006	December 31, 2005	December 31, 2006	December 31, 2005
Discount rate	5.75%	5.63%	5.75%	5.63%
Rate of compensation increase	5.50%	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,		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
Discount rate	5.63%	5.88%	6.25%	5.63% to 5.75%	5.88%	5.88%
Expected return on plan assets	7.50%	7.50%	7.50%	6.15% to 5.00%	6.15% to 5.00%	7.50% to 5.00%
Rate of compensation increase	5.50%	5.50%	5.50%	-	-	-

63

PBOP assumed health care cost trends

Assumed healthcare-cost-trend rates have a significant effect on the amounts reported for PBOP. A one-percentage-point change in assumed healthcare-cost-trend rates would have had the following effects on amounts reported for the years ended December 31, 2006, 2005 and 2004 (in thousands):

Effect of 1% Increase:		**2006**		**2005**		**2004**
Benefit obligation at end of year	$	3,102	$	19,785	$	18,077
Total of service and interest costs for year		927		1,585		1,352
Effect of 1% Decrease:						
Benefit obligation at end of year	$	(2,764)		(16,077)		(14,670)
Total of service and interest costs for year		(757)		(1,263)		(1,078)

For measurement purposes, at December 31, 2006, 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. For December 31, 2005, measurement purposes, health care costs for the plans were assumed to increase 9.0% for 2006-2007, grading down to 5.0% in 0.5% annual increments for participants not eligible for Medicare eligibles and 11.0% grading down to 5.0% in 0.5% annual increments for participants eligible for Medicare.

Defined Contribution Plans

The Partnership maintains defined contribution plans covering substantially all of its employees. Costs related to these plans were $5.1 million, $4.9 million and $2.6 million for the years ended December 31, 2006, 2005 and 2004.

Strategic Long Term Incentive Plan

On July 24, 2006, Boardwalk GP approved the Boardwalk Pipeline Partners 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. 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.

On December 21, 2006, 125 Phantom GP Units were awarded to selected employees that vest in approximately 4.0 years. Concurrent with the approval of the plan, in July 2006, 125 Phantom GP Units were awarded to selected employees that vest in 3.5 years. At December 31, 2006, 250 Phantom GP Units were available for grant under the plan.

The fair value of the awards was determined as of the date of grant, 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, and will be remeasured at each reporting period in accordance with the treatment of awards classified as liabilities prescribed in SFAS No. 123(R). The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement. The Partnership recognized $0.8 million in Administrative and general expenses during 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, 2006, of $11.4 million will be recognized over the average remaining vesting period of approximately 3.5 years.

Long-Term Incentive Plan

During 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 has reserved 3,525,000 units for grants of units, restricted units, unit options and unit appreciation rights under the plan. On December 21, 2006, the Partnership granted 49,387 Phantom Common Units under the LTIP but did not make any grants of units, restricted units, unit options and unit appreciation rights. Each such grant includes: a tandem grant of Distribution Equivalent Rights (DERs); vests 50% on the second anniversary of the grant date; and 50% on the third anniversary of the grant date; and will be payable to the grantee in cash upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date plus the vested amount then credited to the grantee's DER account, less applicable taxes. The fair value of the awards will be recognized ratably over the vesting period and remeasured each quarter until settlement based on the market price of the Partnership's common units and amounts credited under the DERs.

At December 31, 2006, 75,083 Phantom Common Units were outstanding under the plan. During 2006, 3,480 Phantom Common Units were forfeited. On March 23, 2006, the general partner purchased 1,000 of our 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 on March 24, 2006, as part of their director compensation. See Executive Compensation - Director Compensation in Item 11 of this Report. At December 31, 2006, 3,524,000 units were available for grants under LTIP. The Partnership recognized $0.2 million of expense related to the outstanding units during 2006. Amounts recognized in 2005 were immaterial. The total estimated remaining unrecognized compensation expense related to the Phantom Common Units outstanding at December 31, 2006, of $2.1 million will be recognized over the average remaining vesting period of approximately 2.2 years.

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 Issue No. 03-6 (EITF 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 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%	2%
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target Distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	above $0.5250	50%	50%

The amounts reported for net income per limited partner unit on the Consolidated Statements of Income for the years ended December 31, 2006 and 2005, were reduced 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 and not based on the assumed allocation required by EITF No. 03-6. 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 is as follows (in thousands, except weighted average units and per unit data):

	For the Year Ended December 31, 2006	For the Period November 15, 2005 through December 31, 2005
Limited partners' interest in net income	$ 193,599	$ 35,272
Less assumed allocation to incentive distribution rights	5,187	-
Net income available to limited partners	188,412	35,272
Less assumed allocation to subordinated units	61,087	11,382
Net income available to common units	$ 127,325	$ 23,890
Weighted average common units	68,977,766	68,256,122
Weighted average subordinated units	33,093,878	33,093,878
Net income per limited partner unit - common and subordinated units	$ 1.85	$ 0.35

The Partnership has declared quarterly distributions per unit to unitholders of record, including common and subordinated units and the 2% general partner interest held by its general partner as follows:

Record Date	Payable Date	Distribution per Unit
February 20, 2007	February 27, 2007	$ 0.415
October 30, 2006	November 6, 2006	0.40
August 11, 2006	August 18, 2006	0.38
May 12, 2006	May 19, 2006	0.36
February 16, 2006	February 23, 2006	0.1788*

*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.

The Partnership also declared a cash distribution payable to its general partner with respect to its 2.0% general partner interests, and with respect to that portion of the distribution in excess of $0.4025 per unit, its incentive distribution rights described above.

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 has recorded a charge-in-lieu of income taxes for the period January 1, 2005 through the date of the offering and has recorded no charge-in-lieu of income taxes thereafter. Pursuant to the change in tax status, the Partnership also eliminated its balance of accumulated deferred income taxes at the date of the offering. A subsidiary of the Partnership directly incurs some income-based state taxes which are accrued as Income taxes and charge-in-lieu of income taxes on the Consolidated Statements of Income.

Following is a summary of the provision for Income taxes and charge-in-lieu of income taxes for the periods ended December 31, 2006, 2005, and 2004 (in thousands):

	For the Year Ended December 31,					
	2006		2005		2004	
Current expense (benefit):						
Federal		-	$	4,044	$	(9,131)
State	$	292		870		(1,964)
Total		292		4,914		(11,095)
Deferred provision (benefit) :						
Federal		-		36,690		35,803
State		(39)		7,890		7,625
Elimination of cumulative deferred taxes		-		10,102		-
Total		(39)		54,682		43,428
Income taxes and charge-in-lieu of income taxes	$	253	$	59,596	$	32,333

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

	For the Year Ended December 31,					
	2006		2005		2004	
Provision at statutory rate		-	$	43,583	$	28,405
Increases in taxes resulting from:						
State income taxes	$	253		5,694		3,680
Other, net		-		217		248
Elimination of deferred taxes		-		10,102		-
Income taxes and charge-in-lieu of income taxes	$	253	$	59,596	$	32,333

As of December 31, 2006 and 2005, 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; therefore, estimated fair value is based on quoted market prices at December 31, 2006 and 2005.

The carrying amount and estimated fair values of the Partnership's financial instruments as of December 31, 2006 and 2005 were as follows (in thousands):

	2006		2005	
Financial Assets	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Cash and cash equivalents	$ 399,032	$ 399,032	$ 65,792	$ 65,792
Financial Liabilities				
Long-term debt	$ 1,350,920	$ 1,318,293	$ 1,101,290	$ 1,090,854

Note 13: Accumulated Other Comprehensive Income (Loss)

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

	For the Year Ended December 31,			
	2006		2005	
Gain (loss) on cash flow hedges, net of tax	$	8,309	$	(174)
Adjustment to initially apply SFAS No. 158, net of tax		14,803		-
Total Accumulated other comprehensive income (loss), net of tax	$	23,112	$	(174)

Note 14: Major Customers and Transactions with Affiliates

Major Customers

Operating revenues received from major customers (in thousands) and their percentage of Operating Revenues were:

	For the Year Ended December 31,					
	2006		2005		2004	
Customer	**Revenue**	**%**	**Revenue**	**%**	**Revenue**	**%**
ProLiance Energy, LLC	$ 55,129	9.1%	$ 51,168	9.1%	$ 56,742	21.5%
Atmos Energy	56,413	9.3%	61,774	11.0%	28,569	10.8%

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, 2006, the amount of gas loaned by the operating subsidiaries was approximately 15.1 TBtu and, assuming an average market price during December 2006 of $6.81 per million British thermal units (MMBtu), the market value of that gas was approximately $102.8 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.

Related Parties

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 $13.0 million, $9.7 million, and $6.9 million for the years ended December 31, 2006, 2005 and 2004 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 and 2% general partner interest held by Boardwalk GP were $116.6 million during 2006.

Note 15: Recently Issued Accounting Pronouncements

Staff Accounting Bulletin (SAB) No. 108

In September of 2006, the Securities and Exchange Commission (SEC) issued SAB No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements.* This bulletin summarizes the SEC staff's views regarding the process of quantifying financial statement misstatements. SAB No. 108 was effective for reporting periods ending after November 15, 2006. The Partnership has recognized no adjustments to its Consolidated Financial Statements as a result of the application of SAB No. 108.

SFAS No. 158

In September 2006, the FASB issued SFAS No. 158, which requires that an employer with a single-employer defined benefit plan:

(a) recognize the funded status of a benefit plan in its statement of financial position,
(b) recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service cost or credits that arise during the period but are not recognized as components of net periodic benefit cost,
(c) measure defined benefit plan assets and obligations as of the date of the employer's fiscal year-end statement of financial position, and
(d) disclose in the notes to the financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from delayed recognition of gains or losses, prior service cost or credits, and transition asset or obligation.

Entities with publicly traded equity securities were required to adopt SFAS No. 158 for fiscal years ending after December 15, 2006. Gains or losses, prior service costs or credits, and transition assets or obligations that had not yet been included in net periodic benefit cost as of the end of the fiscal year in which SFAS No. 158 is initially applied are recognized as components of the ending balance of accumulated other comprehensive income (AOCI), net of tax. The Partnership began applying the provisions of SFAS No. 158 for its year ended December 31, 2006.

In accordance with SFAS No. 71, certain costs and benefits of a regulated entity are recorded as regulatory assets and liabilities based on expected recovery from customers or refund to customers in future periods. In the application of SFAS No. 158, the Partnership made a determination regarding whether any of the amounts required to be recorded to AOCI should instead be recorded as regulatory assets or liabilities as amounts that will be recoverable from or refundable to customers in future periods. With regard to previously unrecognized actuarial losses related to the pension plan, a determination was made that treatment as a regulatory asset was not appropriate as the recoverability of such amounts in future rates was not deemed probable. For PBOP, a portion of the amount that would otherwise have been recorded in AOCI was instead recorded as a reduction of the regulatory asset to the extent that the plan was overfunded. The regulatory asset for PBOP will continue to be amortized in accordance with the rate case settlement.

The following tables present the incremental effect of applying SFAS No. 158 on individual line items in the Consolidated Balance Sheets for both the retirement plans and PBOP (in thousands):

	Retirement Plans		
	Before Application of SFAS No. 158	**Adjustments**	**After Application of SFAS No. 158**
	$ 7,820	-	$ 7,820

Other Assets - Costs recoverable from customers			
Other Assets - Other	3,561	$ (3,561)	-
Total Assets	$ 11,381	$ (3,561)	$ 7,820
Other Liabilities and Deferred Credits - Other	1,282	14,479	15,761
AOCI (Loss)	-	(18,040)	(18,040)
Total Liabilities and Partners' Capital	$ 1,282	$ (3,561)	$ (2,279)

	PBOP		
	Before Application of SFAS No. 158	**Adjustments**	**After Application of SFAS No. 158**
Current Assets - Costs recoverable from customers	$ 5,415	-	$ 5,415
Other Assets - Costs recoverable from customers	20,692	$ (15, 538)	5,154
Other Assets - Other	-	14,877	14,877
Total Assets	$ 26,107	$ (661)	$ 25,446
Pension and postretirement benefits	$ 33,551	$ (33,551)	-
AOCI Gain	-	32,890	$ 32,890
Total Liabilities and Partners' Capital	$ 33,551	$ (661)	$ 32,890

SFAS No. 157

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.

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

	For the Year Ended December 31, 2006	2005	2004
Cash paid during the period for:			
Interest (net of amount capitalized)	$ 58,111	$ 45,357	$ 28,847
Income taxes, net	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 2006 and 2005 for the Partnership (in thousands):

	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	13,348	14,424	14,517	15,632
Other expense (income)	168	(416)	(799)	(729)
Income before income taxes	65,162	30,765	32,146	69,730
Charge-in-lieu of income taxes	(111)	118	246	-
Net income	$ 65,273	$ 30,647	$ 31,900	$ 69,730

	2005			
	For the Quarter Ended:			
	December 31	September 30	June 30	March 31
Operating revenues	$ 170,905	$ 120,916	$ 118,263	$ 150,382
Operating expenses	89,378	99,898	81,910	73,800
Operating income	81,527	21,018	36,353	76,582
Interest expense, net	14,964	14,632	14,482	14,511
Other income	722	1,215	922	771
Income before income taxes	67,285	7,601	22,793	62,842
Charge-in-lieu of income taxes	22,476	3,047	9,088	24,985
Net income	$ 44,809	$ 4,554	$ 13,705	$ 37,857

Note 18: 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 loans to the Partnership and have no restricted assets at December 31, 2006. 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

We maintain a system of disclosure controls and procedures which are designed to ensure that information required to be disclosed in reports filed or submitted under the federal securities laws, including this report, is recorded, processed, summarized and reported on a timely basis. These disclosure controls and procedures are designed to ensure that information required to be disclosed under the federal securities laws is accumulated and communicated to management on a timely basis to allow assessment of required disclosures.

Our principal executive officer and principal financial officer have conducted an evaluation of the disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation, the principal executive officer and principal financial officer have each concluded that the disclosure controls and procedures are effective for their intended purpose.

There was no change in our internal control over financial reporting identified in connection with the foregoing evaluation that occurred during the fourth quarter 2006 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined by the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. It consists of policies and procedures that:

· Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;

· Provide reasonable assurance that transactions are recorded as necessary to permit preparation of the financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and

· Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on the 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 controls can provide no more than reasonable assurance with respect to the fair presentation of financial statements and the processes under which they were prepared.

Under the supervision and with the participation of management, including the Chief Executive Officer (CEO) and Chief Financial Officer (CFO), we made an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006. In making this assessment, we used the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our evaluation, we concluded that our internal control over financial reporting was effective as of December 31, 2006. Our assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006 has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report included in Item 8.

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	53	Chief Executive Officer and Director
H. Dean Jones II	54	President and Director
Jamie L. Buskill	42	Chief Financial Officer
Arthur L. Rebell	66	Director, Chairman of the Board
William R. Cordes	58	Director
Thomas E. Hyland	61	Director
Jonathan E. Nathanson	45	Director
Mark L. Shapiro	62	Director
Andrew H. Tisch	57	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. Prior thereto he had been the Co-President of BGL since its inception in 2005. Mr. Gafvert has been the President of Gulf South since 2000 and has been employed by Gulf South or its predecessors since 1993. During that time he also served in various management roles for affiliates of Gulf South, including President of Koch Power, Inc., Managing Director of Koch Energy International and Vice President of Corporate Development for Koch Energy, Inc. Mr. Gafvert is also on the Board of Directors of the Interstate Natural Gas Association of America and the Southern Gas Association.

H. Dean Jones II—Mr. Jones has been the President of BGL since its inception in 2005. Mr. Jones is also the President of Texas Gas Transmission. He 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 1980, including as Vice President, Commercial Operations of Texas Gas from November 2002 until May 2003, Vice President, Customer Service of Williams Gas Pipelines Eastern Region in 2002 and Vice President, Customer Services and Rates of Williams Gas Pipelines South Central from 2000 until 2002. Mr. Jones is also on the Board of Directors of the Interstate Natural Gas Association of America, the Southern Gas Association and Corporate TeleLink Network.

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 Transmission. 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.

Arthur L. Rebell—Mr. Rebell is a Senior Vice President at Loews Corporation. 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, a subsidiary of Loews.

William R. Cordes—Mr. Cordes has been President of Northern Border Pipeline Company since April 2006. He has 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.

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 Corporation. 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 Corporation since January 2006 and is the Chairman of the Executive Committee and a member of the Office of the President of Loews Corporation. He has served as a director of Loews Corporation since 1985. Mr. Tisch also serves as a director of CNA Financial Corporation, a subsidiary of Loews.

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 rules.

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

Conflicts Committee

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

Executive Sessions of Non-Management Directors

Our Board's non-management directors, from time to time as such directors deem necessary or appropriate, meet in executive sessions without management participation. The Chairman of the Audit Committee and the 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 co-principal executive officers, 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% 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 2006, in a timely manner.

76

Item 11. Executive Compensation

Compensation Discussion and Analysis

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 considered 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 of our Named Executive Officers is reviewed with and is subject to the approval of our entire Board, with Messrs. Gafvert and Jones not participating in those discussions with respect to their own compensation. Named Executive Officers are those officers whose compensation is required to be reported 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, the primary factor 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 also review and consider compensation levels and types in other companies that are engaged in similar businesses. Based on these factors, we determine an overall level of compensation.

Base Salary

Since the completion of our IPO in November 2005, our executive compensation policies have emphasized the incentive based compensation elements discussed below. As a result, the base salaries of our executive officers generally remained unchanged through the end of 2006, with modest adjustments made from year to year in some cases. 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.

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% on the second anniversary of the grant date and 50% on the third anniversary of the grant date, and become payable in cash upon vesting. Since the value of the Phantom Common Units is tied directly to the price of our common units, and the amount of distributions made on those units during the vesting period, this element of compensation directly aligns the interests of our 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 2006 and increased our distributions to unitholders in each quarter. As a result, we paid out the full amount of incentive compensation we had targeted for 2006 to our key employees including the Named Executive Officers, of which approximately 75% was paid as annual cash bonuses and 25% 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 2006 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 from our general partner 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 equity holders.

We awarded an aggregate of 125 Phantom GP Units in December 2006, which vest in 4.0 years, to 13 of our key employees, of which 50 were awarded to our Named Executive Officers. In July 2006, in connection with our adoption of our Strategic Long Term Incentive Plan our Board awarded 125 Phantom GP Units, which vest in 3.5 years to 13 of our key employees as compensation for their performance in 2005, of which 52 were awarded to our Named Executive Officers. Consistent with the 2006 awards of incentive compensation discussed above, in making these awards, our Board considered each grantee's overall performance, with particular emphasis on the contributions made by the individual executive to our expansion projects, among other strategic goals and objectives.

Employee Benefits

Each Named Executive Officer participates in benefit programs available generally to salaried employees of the operating subsidiary which employs such officer, including health and welfare benefits and a qualified defined contribution 401(k) plan that includes a dollar-for-dollar match on elective deferrals of up to 6% of eligible compensation within Internal Revenue Code (IRC) requirements. Mr. Gafvert participates in a defined contribution money purchase plan available to employees of Gulf South. Messrs. Jones and Buskill 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. Messrs. Jones and Buskill 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
H. Dean Jones II
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 Messrs. Gafvert and Jones, have been or are officers or employees of us or our subsidiaries. Messrs. Gafvert and Jones participate in deliberations of our Board with regard to executive compensation generally, but do not participate in deliberations or Board actions with respect to their 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 2006.

Summary of Executive Compensation

The following table shows a summary of total compensation earned by our Named Executive Officers during 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	2006	$ 240,000	$300,000	$112,944	-	$183,442	-	$ 32,149 (4)	$ 868,535
Chief Executive Officer and Director									
H. Dean Jones II	2006	325,000	195,000	59,778	-	110,065	154,458 (5)	24,432 (5)	868,733
President and Director									
Jamie L. Buskill	2006	225,000	100,000	26,196	-	87,011	40,333 (6)	14,292 (6)	492,832
Chief Financial Officer									

(1) Reflects cash amounts paid in 2007 to the Named Executive Officers for services performed by them during 2006.

(2) Represents compensation expense accrued for 2006 related to Phantom Common Units granted in 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 2006 related to Phantom GP Units granted in 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 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 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 includes the change in qualified retirement plan account balance ($60,562), interest and pay credits for the supplemental retirement plan ($83,935) and excess nonqualified deferred compensation plan earnings ($9,961).

(6) Includes 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 includes the change in qualified retirement plan account balance ($28,675) and interest and pay credits for the supplemental retirement plan ($11,658).

Grants of Plan-Based Awards

The following table displays information regarding grants during 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 (2006)**	**Thres-hold ($)**	**Target ($)**	**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 Gafvert	12/20	-	-	1,250,000	-	-	-	6,427	-	-	200,000
	7/24	-	-	1,250,000	-	-	-	-	-	-	
H. Dean Jones II	12/20	-	-	750,000	-	-	-	2,571	-	-	80,000
	7/24	-	-	750,000	-	-	-	-	-	-	
Jamie Buskill	12/20	-	-	500,000	-	-	-	1,205	-	-	37,500
	7/24	-	-	600,000	-	-	-	-	-	-	

(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. Concurrent with the approval of the Plan, Messrs. Gafvert, Jones and Buskill were awarded 25, 15 and 12 Phantom GP Units, that have a 3.5 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. 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 July 24, 2006 grants and the December 20, 2006 grants were $27,422 and $50,000, respectively, per GP Phantom Unit. The fair value of the awards will be recognized ratably over the vesting period. As of December 31, 2006 the remeasured fair value of each of the July 24, 2006 grants was $47,718 and the fair value of each of the December 20, 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 was $31.12. Each such grant includes a tandem grant of Distribution Equivalent Rights (DERs); vests 50% on the second anniversary of the grant date and 50% on the third anniversary of the grant date; and will be payable to the grantee in cash upon vesting in an amount equal to the sum of the fair market value of the units (as defined in the plan) that vest on the vesting date plus the vested amount then credited to the grantee’s DER account, less applicable taxes. Note 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, 2006:

Outstanding Equity Awards at Fiscal Year End

	Option Awards					Stock Awards			
Name	**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 Gafvert	-	-	-	-	-	14,457	456,155	-	-
H.Dean Jones II	-	-	-	-	-	6,854	216,888	-	-
Jamie Buskill	-	-	-	-	-	3,079	97,366	-	-

(1) On December 15, 2005, Phantom Common Units were awarded 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. 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.

(2) The market value per share reported in the above table is based on the NYSE last sale price on 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 and Buskill were $10,590, $5,648 and $2,471.

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. As of December 31, 2006, none of the awards issued to our Named Executive Officers have vested. We have not issued any awards in the form of options on our units to any employees including 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	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($)	Payments During 2006 ($)
H. Dean Jones II	TGRP	26.1	$470,863	-
	SRP	26.1	576,311	-
Jamie Buskill	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% age 40 through 49 and 10% age 50 and older. Additional credit rates on annual pay above Social Security Wage Base is 1%, 2%, 3% and 5% 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 retirees 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, 2006, neither Mr. Jones nor Mr. Buskill are 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 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 Name Executive Officer, is determined using assumptions consistent with the assumptions used for financial reporting. Interest is credited, to the cash balance at December 31, 2006, commencing in the year 2007 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, 2006 were 4.85% for 2006 and 4.25% for future years. Credited interest rates at December 31, 2005 were 4.47% and 4.125% for future years. The future normal retirement date accumulated cash balance is then discounted using an interest rate at December 31, 2006 of 5.75% (5.625% at December 31, 2005). The December 31, 2005, present value of accumulated benefits for Messers. Jones and Buskill were $410,301 and $113,974. 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 December 31, 2005 present value of accumulated benefits under the SRP for Messers. Jones and Buskill were $492,376 and $7,221. 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	Executive Contributions in 2006 ($)	Registrant Contributions in 2006 ($)	Aggregate Earnings in 2006 ($)	Aggregate Withdrawals/ Distributions during 2006 ($)	Aggregate Balance at December 31, 2006 ($)
H. Dean Jones II	-	-	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%, compounded monthly. Aggregate earnings in 2006 includes $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 February 15, 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 $35.40, 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:

Name	Total

	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (4)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings	All Other Compensation including perquisites ($)	($)
William R. Cordes	8,750 (2)	-	-	-	-	-	8,750
Thomas E. Hyland	60,667 (3)	10,800	-	-	-	-	71,467
Mark L. Shapiro	54,833	10,800	-	-	-	-	65,633

(1) Represents amounts paid in cash for 2006.
(2) Mr. Cordes commenced serving on the Board in the fourth quarter 2006.
(3) Chairman of Audit Committee.
(4) On March 24, 2006, Messrs. Hyland and Shapiro were each granted 500 common units.
The closing sales price on the NYSE on March 24, 2006 was $21.60 per unit.

Item 12. Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information, at February 9, 2007, as to the beneficial ownership of our common and subordinated units by beneficial holders of 5% or more of either such class of units, each member of our Board, each of the Named Executive Officers and all of our executive officers and directors as a group, based on data furnished by them:

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	-	-	-	-	-
William R. Cordes					
Rolf A. Gafvert	-	-	-	-	-
Thomas E. Hyland	5,500	*	-	-	-
H. Dean Jones II	-	-	-	-	-
Jonathan E. Nathanson	10,000	*	-	-	-
Arthur L. Rebell	36,583 (2)	*	-	-	-
Mark L. Shapiro	10,500	*	-	-	-
Andrew H. Tisch	18,550 (3)	*	-	-	-
All directors and executive officers as a group	81,133	*	-	-	-
BPHC (4)	53,256,122	70.86%	33,093,878	100.00%	80.17%
Loews Corporation (4)	53,256,122	70.86%	33,093,878	100.00%	80.17%

*Represents less than 1% of the outstanding common units

(1) As of February 9, 2007, we had 75,156,122 common units and 33,093,878 subordinated units issued and outstanding.

(2) 30,583 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 3800 Frederica Street, Owensboro, Kentucky 42301. The address of Loews is 667 Madison Avenue, New York, New York 10021.

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, 2006 with respect to this plan (in thousands):

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	3,524,000

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% 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 million, or 2% of the other company's consolidated gross revenues.

Our Board has appointed an Audit Committee comprised solely of independent directors. The NYSE does not require a listed limited partnership, or a listed company that is majority-owned by another listed company, such as us, to have a majority of independent directors on its board of directors or to maintain a compensation or nominating/corporate governance committee. In reliance on these exemptions, our Board is not comprised of a majority of independent directors, 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 2006 and 2005, by category as described in the notes to the table (in thousands):

	2006	2005
Audit fees (1)	$ 1,513	$ 1,271
Audit related fees (2)	553	990
Tax fees (3)	2	6
Total	$ 2,068	$ 2,267

(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, accounting consultations, Sarbanes-Oxley implementation, and due diligence for the GS-Acquisition and other potential acquisitions.

(3) Includes the aggregate fees and expenses for tax compliance and tax planning 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. Prior to November 2005, the Audit Committee of Loews served as the audit committee of our predecessor and its subsidiaries and pre-approved all engagements by our predecessor and its subsidiaries during 2005, including the terms and fees thereof, and the Loews Audit Committee concluded that all such engagements were compatible with the continued independence of Deloitte & Touche in serving as the independent auditor of such companies.

PART IV

Item 15. Exhibits, 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, 2006 and 2005

Consolidated Statements of Income for the years ended December 31, 2006 and 2005 and 2004

Consolidated Statements of Cash Flows for the years ended December 31, 2006 and 2005 and 2004

Consolidated Statements of Changes in Member's Equity and Partners' Capital for the years ended December 31, 2006 and 2005 and 2004

Consolidated Statements of Comprehensive Income for the years ended December 31, 2006 and 2005 and 2004

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, 2006, 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:					
2006	$ 730	$ 2,053	-	$ 173	$ 2,610
2005	174	745	$ (187)	2	730
2004	203	-	-	29	174
Inventory obsolescence:					
2006	-	33	-	-	33
2005	201	-	11	212	-
2004	630	-	16	445	201

(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	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).
10.3	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).
10.4	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).
10.5	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).
10.6	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).
10.7	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).
10.8	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).
10.9	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)
10.10	Boardwalk Pipeline Partners 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).
10.11	Form of Phantom Unit Award Agreement under the Boardwalk Pipeline Partners 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).
10.12	Boardwalk Pipeline Partners 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).
10.13	Form of GP Phantom Unit Award Agreement under the Boardwalk Pipeline Partners 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).
10.14	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.
*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	Certifications 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 23, 2007	By:	*/s/ Jamie L. Buskill* Jamie L. Buskill Chief Financial Officer

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 23, 2007	*/s/ Rolf A. Gafvert* Rolf A. Gafvert	Chief Executive Officer and Director (principal executive officer)
Dated: February 23, 2007	*/s/ H. Dean Jones II* H. Dean Jones II	President and Director
Dated: February 23, 2007	*/s/ Jamie L. Buskill* Jamie L. Buskill	Chief Financial Officer (principal financial officer)
Dated: February 23, 2007	*/s/ Steven A. Barkauskas* Steven A. Barkauskas	Vice President and Corporate Controller (principal accounting officer)
Dated: February 23, 2007	*/s/ William R. Cordes* William R. Cordes	Director
Dated: February 23, 2007	*/s/ Thomas E. Hyland* Thomas E. Hyland	Director
Dated: February 23, 2007	*/s/ Jonathon E. Nathanson* Jonathon E. Nathanson	Director
Dated: February 23, 2007	*/s/ Arthur L. Rebell* Arthur L. Rebell	Director
Dated: February 23, 2007	*/s/ Mark L. Shapiro* Mark L. Shapiro	Director
Dated: February 23, 2007	*/s/ Andrew H. Tisch* Andrew H. Tisch	Director

90