Boardwalk Pipeline Partners, LP
Form 10-Q
July 31, 2009

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2009

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _______________ to _______________

Commission file number: 01-32665

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

DELAWARE
(State or other jurisdiction of incorporation or organization)

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

9 Greenway Plaza, Suite 2800
Houston, Texas 77046
(866) 913-2122
(Address and Telephone Number of Registrant's Principal Executive Office)

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

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

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

Indicate by check mark 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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ Noo

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

Large accelerated filer x   Accelerated filer o   Non-accelerated filer o   Smaller reporting company o

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

As of July 31, 2009, the registrant had 161,619,466 common units outstanding and 22,866,667 class B units outstanding.

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PART I – FINANCIAL INFORMATION

Item 1. Financial Statements

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions)
(Unaudited)

ASSETS	June 30, 2009	December 31, 2008
Current Assets:		
Cash and cash equivalents	$71.8	$137.7
Short-term investments	-	175.0
Receivables:		
Trade, net	65.3	67.3
Other	24.7	18.0
Gas transportation receivables	9.5	13.5
Inventories	4.8	2.6
Costs recoverable from customers	5.4	5.4
Gas stored underground	1.7	0.2
Prepayments	12.1	17.3
Other current assets	12.3	14.8
Total current assets	207.6	451.8
Property, Plant and Equipment:		
Natural gas transmission plant	6,217.9	3,871.0
Other natural gas plant	219.5	215.2
	6,437.4	4,086.2
Less—accumulated depreciation and amortization	476.4	382.4
	5,961.0	3,703.8
Construction work-in-progress	207.3	2,196.4
Property, plant and equipment, net	6,168.3	5,900.2
Other Assets:		
Goodwill	163.5	163.5
Gas stored underground	133.7	124.8
Costs recoverable from customers	15.2	15.4
Other	87.3	65.9
Total other assets	399.7	369.6
Total Assets	$6,775.6	$6,721.6

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

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BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED BALANCE SHEETS
(Millions)
(Unaudited)

LIABILITIES AND PARTNERS' CAPITAL	June 30, 2009	December 31, 2008
Current Liabilities:		
Payables:		
Trade	$102.0	$216.4
Affiliates	1.3	1.8
Other	6.9	7.4
Gas transportation payables	12.6	11.6
Accrued taxes, other	54.0	35.2
Accrued interest	34.7	40.1
Accrued interest - affiliate	1.7	-
Accrued payroll and employee benefits	13.7	16.3
Construction retainage	39.4	76.3
Deferred income	13.7	1.8
Other current liabilities	34.2	27.1
Total current liabilities	314.2	434.0
Long –term debt	2,801.9	2,889.4
Long –term debt - affiliate	200.0	-
Total long-term debt	3,001.9	2,889.4
Other Liabilities and Deferred Credits:		
Pension liability	38.2	35.7
Asset retirement obligation	16.7	18.0
Provision for other asset retirement	47.9	45.6
Payable to affiliate	26.7	20.6
Other	46.3	33.3
Total other liabilities and deferred credits	175.8	153.2
Commitments and Contingencies		
Partners' Capital:		
Common units – 161.6 million units issued and outstanding as of June 30, 2009, and 154.9 million units issued and outstanding as of December 31, 2008	2,552.9	2,504.8
Class B units – 22.9 million units issued and outstanding as of June 30, 2009, and December 31, 2008	687.4	692.8
General partner	63.8	62.9
Accumulated other comprehensive loss	(20.4)	(15.5)
Total partners' capital	3,283.7	3,245.0
Total Liabilities and Partners' Capital	$6,775.6	$6,721.6

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Millions, except per unit amounts)
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Operating Revenues:				
Gas transportation	$169.3	$160.2	$370.2	$336.7
Parking and lending	8.4	4.6	15.8	9.7
Gas storage	14.3	13.6	27.9	24.3
Other	9.4	11.9	10.9	16.9
Total operating revenues	201.4	190.3	424.8	387.6
Operating Costs and Expenses:				
Fuel and gas transportation	10.8	31.2	26.5	47.1
Operation and maintenance	32.2	23.7	63.0	48.6
Administrative and general	30.6	27.3	59.5	52.5
Depreciation and amortization	51.6	30.4	98.0	57.8
Contract settlement gain	-	-	-	(11.2)
Asset impairment	-	-	-	1.4
Net loss (gain) on disposal of operating assets and related contracts	5.5	(14.2)	6.4	(14.0)
Taxes other than income taxes	17.5	10.9	39.6	22.9
Total operating costs and expenses	148.2	109.3	293.0	205.1
Operating income	53.2	81.0	131.8	182.5
Other Deductions (Income):				
Interest expense	31.3	17.7	57.9	36.7
Interest expense - affiliates	1.7	-	1.7	-
Interest income	(0.1)	(0.4)	(0.2)	(1.4)
Miscellaneous other income, net	-	(1.2)	(0.2)	(6.1)
Total other deductions	32.9	16.1	59.2	29.2
Income before income taxes	20.3	64.9	72.6	153.3
Income taxes	-	0.2	0.3	0.5
Net Income	$20.3	$64.7	$72.3	$152.8

Net Income per Unit:	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Basic and diluted net income per unit:				
Common units (a)	$0.12	$0.50	$0.41	$1.18

Class B units	$(0.09)	$-	$0.02	$-
Subordinated units (a)	$-	$0.46	$-	$1.14
Cash distribution to common and subordinated units (a)	$0.485	$0.465	$0.965	$0.925
Cash distribution to class B units	$0.30	$-	$0.60	$-
Weighted-average number of units outstanding:				
Common units (a)	155.5	92.3	155.2	91.5
Class B units	22.9	-	22.9	-
Subordinated units (a)	-	33.1	-	33.1

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

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

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BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Millions)
(Unaudited)

	For the Six Months Ended June 30, 2009	2008
OPERATING ACTIVITIES:		
Net income	$72.3	$152.8
Adjustments to reconcile to cash provided by operations:		
Depreciation and amortization	98.0	57.8
Amortization of deferred costs	4.6	4.4
Amortization of acquired executory contracts	-	(0.2)
Asset impairment	-	1.4
Net loss (gain) on disposal of operating assets and related contracts	6.4	(14.0)
Changes in operating assets and liabilities:		
Trade and other receivables	(2.7)	(26.5)
Gas receivables and storage assets	(6.4)	(1.0)
Costs recoverable from customers	-	(0.2)
Inventories	(22.2)	(1.6)
Other assets	(22.8)	(10.7)
Trade and other payables	1.2	1.2
Other payables, affiliates	1.2	0.4
Gas payables	2.4	22.8
Accrued liabilities	5.6	8.1
Other liabilities	30.1	(23.1)
Net cash provided by operating activities	167.7	171.6
INVESTING ACTIVITIES:		
Capital expenditures	(497.2)	(1,089.5)
Proceeds from sale of operating assets	-	4.9
Proceeds from insurance reimbursements and other recoveries	-	3.8
Advances to affiliates, net	-	(1.1)
Sales of short-term investments	175.0	-
Net cash used in investing activities	(322.2)	(1,081.9)
FINANCING ACTIVITIES:		
Proceeds from long-term debt, net of issuance costs	-	247.2
Proceeds from borrowings on revolving credit agreement	161.5	518.0
Repayment of borrowings on revolving credit agreement	(250.0)	(518.0)
Payments on note payable	(0.3)	-
Proceeds from long-term debt - affiliate	200.0	-
Distributions	(172.6)	(120.1)
Proceeds from sale of common units	147.0	243.3
Proceeds from sale of class B units	-	686.0
Capital contribution from general partner	3.0	19.2
Net cash provided by financing activities	88.6	1,075.6
(Decrease) increase in cash and cash equivalents	(65.9)	165.3
Cash and cash equivalents at beginning of period	137.7	317.3

Cash and cash equivalents at end of period	$71.8	$482.6

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(Millions)
(Unaudited)

	Common Units	Class B Units	Subordinated Units	General Partner	Accumulated Other Comp Income (Loss)	Total Partners' Capital
Balance January 1, 2008	$1,473.9	$-	$ 291.7	$33.2	$ 4.2	$1,803.0
Add (deduct):						
Net income	107.6	-	39.0	6.2	-	152.8
Distributions paid	(83.8)	-	(30.7)	(5.6)	-	(120.1)
Sale of common units, net of related transaction costs (10.0 million common units)	243.3	-	-	-	-	243.3
Sale of class B units (22.9 million class B units)	-	686.0	-	-	-	686.0
Capital contribution from general partner	-	-	-	19.2	-	19.2
Other comprehensive loss	-	-	-	-	(34.2)	(34.2)
Balance June 30, 2008	$1,741.0	$686.0	$ 300.0	$53.0	$ (30.0)	$2,750.0
Balance January 1, 2009	$2,504.8	$692.8	$ -	$62.9	$ (15.5)	$3,245.0
Add (deduct):						
Net income	56.7	8.3	-	7.3	-	72.3
Distributions paid	(149.5)	(13.7)	-	(9.4)	-	(172.6)
Sale of common units, net of related transaction costs (6.7 million common units)	140.9	-	-	3.0	-	143.9
Other comprehensive loss	-	-	-	-	(4.9)	(4.9)
Balance June 30, 2009	$2,552.9	$687.4	$ -	$63.8	$ (20.4)	$3,283.7

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

BOARDWALK PIPELINE PARTNERS, LP

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Millions)
(Unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2009	2008	2009	2008
Net income	$20.3	$64.7	$72.3	$152.8
Other comprehensive (loss) income:				
(Loss) gain on cash flow hedges	-	(23.0)	8.0	(47.4)
Reclassification adjustment transferred to Net income from cash flow hedges	(7.0)	17.0	(8.0)	17.6
Pension and other postretirement benefits costs	(1.0)	(2.2)	(4.9)	(4.4)
Total Comprehensive Income	$12.3	$56.5	$67.4	$118.6

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

BOARDWALK PIPELINE PARTNERS, LP

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1: Basis of Presentation

Boardwalk Pipeline Partners, LP (the Partnership) is a Delaware limited partnership formed to own and operate the business conducted by its subsidiary, Boardwalk Pipelines, LP (Boardwalk Pipelines), and its subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (collectively, the operating subsidiaries). As of June 30, 2009, Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews) owned 114.2 million of the Partnership's common units, all 22.9 million of the Partnership's class B units and, through Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of the incentive distribution rights (IDRs). As of June 30, 2009, the common units, class B units and general partner interest owned by BPHC represent approximately 75% of the Partnership's equity interests, excluding the IDRs. The Partnership's common units are traded under the symbol "BWP" on the New York Stock Exchange.

The accompanying unaudited condensed consolidated financial statements of the Partnership were prepared pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to such rules and regulations. In the opinion of management, the accompanying condensed consolidated financial statements reflect all adjustments (consisting of only normal recurring accruals) necessary to present fairly the financial position as of June 30, 2009, and December 31, 2008, and the results of operations and comprehensive income for the three and six months ended June 30, 2009 and 2008, and changes in cash flow and changes in partners' equity for the six months ended June 30, 2009 and 2008. Reference is made to the Notes to Consolidated Financial Statements in the 2008 Annual Report on Form 10-K, which should be read in conjunction with these unaudited condensed consolidated financial statements. The accounting policies described in Note 2 to the Consolidated Financial Statements included in such Annual Report on Form 10-K are the same used in preparing the accompanying unaudited condensed consolidated financial statements.

Net income for interim periods may not necessarily be indicative of results for the full year. All intercompany items have been eliminated in consolidation. Subsequent events have been evaluated through July 31, 2009, the issuance date of these financial statements.

Note 2: Gas Stored Underground and Gas Receivables and Payables

Gulf South and Texas Gas provide storage services whereby they store gas on behalf of customers. The pipelines also periodically hold customer gas under parking and lending (PAL) services. Since the customers retain title to the gas held by the Partnership in providing these services, the Partnership does not record the related gas on its balance sheet. The Partnership held for storage or under PAL agreements approximately 82.0 trillion British thermal units (TBtu) of gas owned by third parties as of June 30, 2009. Assuming an average market price during June 2009 of $3.67 per million British thermal unit (MMBtu), the market value of gas held on behalf of others was approximately $300.9 million. As of December 31, 2008, the Partnership held for storage or under PAL agreements approximately 63.8

TBtu of gas owned by third parties.

In the course of providing transportation and storage services to customers, the operating subsidiaries may receive different quantities of gas from shippers and operators than the quantities delivered on behalf of those shippers and operators. This results in transportation and exchange gas receivables and payables, commonly known as imbalances, which are settled in cash or the receipt or delivery of gas in the future. Gulf South and Texas Gas also periodically lend gas to customers under PAL services. As of June 30, 2009, the amount of gas loaned out under PAL agreements and the amount of gas owed to the operating subsidiaries due to gas imbalances was approximately 18.9 TBtu. Assuming an average market price during June 2009 of $3.67 per MMBtu, the market value of that gas was approximately $69.4 million. As of December 31, 2008, the amount of gas loaned out under PAL agreements and the amount of gas owed to the operating subsidiaries due to gas imbalances was approximately 34.4 TBtu. If any significant customer should have credit or financial problems resulting in a delay or failure to repay the gas owed to the operating subsidiaries, it could have a material adverse effect on the Partnership's financial condition, results of operations and cash flows.

Note 3: Derivative Financial Instruments

In 2009, the Partnership began applying the provisions of Statement of Financial Accounting Standards (SFAS) No. 161, Disclosures about Derivative Instruments and Hedging Activities, which requires entities to provide additional information about their derivative instruments and hedging activities. The application of SFAS No. 161 had no effect on the Partnership's financial condition, results of operations and cash flows. Additional information required under the standard is contained in the following disclosures.

Subsidiaries of the Partnership use futures, swaps, and option contracts (collectively, derivatives) to hedge exposure to natural gas commodity price risk related to the future operational sales of natural gas and cash for fuel reimbursement. This includes approximately $1.7 million and $0.2 million of gas stored underground at June 30, 2009 and December 31, 2008, which the Partnership owns and carries on its balance sheets as current Gas stored underground, and 3.3 billion cubic feet (Bcf) of gas with a book value of $7.5 million that has become available for sale as a result of Phase III of the Western Kentucky Storage Expansion. At June 30, 2009, approximately 6.8 Bcf of anticipated future sales of natural gas and cash for fuel reimbursement were hedged with derivatives having settlement dates in 2009 and 2010. The derivatives qualify for cash flow hedge accounting under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and are designated as such. The Partnership has also periodically used derivatives as cash flow hedges of interest rate risk in anticipation of debt offerings.

All of the Partnership's derivatives are reported at fair value in accordance with SFAS No. 133. The currently outstanding derivatives are recorded at fair value based on New York Mercantile Exchange (NYMEX) quotes for natural gas futures and options. The NYMEX quotes are deemed to be observable inputs in an active market for similar assets and liabilities and are considered Level 2 inputs for purposes of fair value disclosures under SFAS No. 157, Fair Value Measurements. The Partnership has not changed its valuation techniques or inputs during the reporting period.

The fair values of derivatives existing as of June 30, 2009, and December 31, 2008, were included in the following captions in the Condensed Consolidated Balance Sheets (in millions):

	Asset Derivatives				Liability Derivatives			
	June 30, 2009		December 31, 2008		June 30, 2009		December 31, 2008	
	Balance sheet location	Fair Value	Balance sheet location	Fair Value	Balance sheet location	Fair Value	Balance sheet location	Fair Value
Derivatives designated as hedging instruments under SFAS No. 133								
Commodity contracts	Other current assets	$ 9.6	Other current assets	$ 10.5	Other current liabilities	$ -	Other current liabilities	$ 0.1
	Other assets	2.8	Other assets	3.7	Other liabilities	0.8	Other liabilities	-
		$ 12.4		$ 14.2		$ 0.8		$ 0.1

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 it becomes probable that the anticipated transactions will not occur, hedge accounting would be terminated and changes in the fair values of the associated derivative financial instruments would be recognized currently in earnings. The Partnership did not discontinue any cash flow hedges during the three and six month periods ended June 30, 2009 and 2008.

The effective component of unrealized gains and losses resulting from changes in fair values of the derivatives designated as cash flow hedges are deferred as a component of Accumulated other comprehensive income (loss) (AOCI). The deferred gains and losses associated with the anticipated operational sale of gas reported as current Gas stored underground are recognized in operating revenues when the anticipated transactions affect earnings. The deferred gains and losses associated with the anticipated sale of gas that has become available for sale as a result of Phase III of the Western Kentucky Storage Expansion are recognized in Net loss (gain) on disposal of operating assets and related contracts when the anticipated transactions affect earnings. In situations where continued reporting of a loss in AOCI would result in recognition of a future loss on the combination of the derivative and the hedged transaction, SFAS No. 133 requires that the loss be immediately recognized in earnings for the amount that is not expected to be recovered. No such losses were recognized in the three and six month periods ended June 30, 2009, and $1.7 million of losses were recognized for the three and six month periods ended June 30, 2008.

The amount of gains and losses from derivatives recognized in the Condensed Consolidated Statements of Income for the three months ended June 30, 2009, were (in millions):

Derivatives in SFAS No. 133 Cash Flow Hedging Relationship	Amount of gain/(loss) recognized in AOCI on derivatives (effective portion)	Location of gain/(loss) reclassified from AOCI into income (effective portion)	Amount of gain/(loss) reclassified from AOCI into income (effective portion)	Location of gain/(loss) recognized in income on derivative (in- effective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (in- effective portion and amount excluded from effectiveness testing)
Commodity contracts	$-	Operating revenues	$7.6	Net gain/(loss) on disposal of operating assets and related contracts	$ (0.2)
Interest rate contracts (1)	-	Interest expense	(0.4)	N/A	-
	$-		$7.2		$ (0.2)

(1) Related to amounts deferred in AOCI from Treasury rate locks used in hedging interest payments associated with debt offerings which were settled in previous periods and are being amortized to earnings over the terms of related interest payments, generally the terms of the related debt.

The amount of gains and losses from derivatives recognized in the Condensed Consolidated Statements of Income for the six months ended June 30, 2009, were (in millions):

Derivatives in SFAS No. 133 Cash Flow Hedging Relationship	Amount of gain/(loss) recognized in AOCI on derivatives (effective portion)	Location of gain/(loss) reclassified from AOCI into income (effective portion)	Amount of gain/(loss) reclassified from AOCI into income (effective portion)	Location of gain/(loss) recognized in income on derivative (in- effective portion and amount excluded from effectiveness testing)	Amount of gain/(loss) recognized in income on derivative (in- effective portion and amount excluded from effectiveness testing)
Commodity contracts	$8.0	Operating revenues	$9.0		$ (0.2)

				Net gain/(loss) on disposal of operating assets and related contracts	
Interest rate contracts (1)	-	Interest expense	(0.8)	N/A	-
	$8.0		$8.2		$ (0.2)

(1) Related to amounts deferred in AOCI from Treasury rate locks used in hedging interest payments associated with debt offerings which were settled in previous periods and are being amortized to earnings over the terms of related interest payments, generally the terms of the related debt.

In the first quarter 2008, approximately 5.1 Bcf of gas stored underground with a book value of $11.8 million became available for sale related to the Western Kentucky Storage Expansion. The Partnership entered into derivatives, which were designated as cash flow hedges, to hedge the price exposure related to the expected sale of this gas. Approximately 2.2 Bcf of this gas was sold in the second quarter 2008, and the related derivatives were settled, resulting in a gain of $14.7 million which was reported in Net loss (gain) on disposal of operating assets and related contracts on the Condensed Consolidated Statements of Income.

The Partnership has entered into master netting agreements to manage counterparty credit risk associated with its derivatives, however it does not offset on its balance sheets fair value amounts recorded for derivative instruments under these agreements. At June 30, 2009, all of the Partnership's derivatives were with two counterparties, however outstanding asset positions under derivative contracts have not resulted in a material concentration of credit risk.

In accordance with the contracts governing the Partnership's derivatives, the counterparty or the Partnership may be required to post cash collateral when credit risk exceeds certain thresholds. Contractual provisions with one counterparty require that cash collateral be posted to the extent the fair value amount payable to the other party exceeds $5.0 million. The threshold for posting collateral with the other counterparty varies based on the credit ratings of the contracting subsidiary of the Partnership or the counterparty. Based on credit ratings at June 30, 2009, the Partnership would be required to post cash collateral to the extent the fair value amount payable to the other party exceeds $10.0 million and the counterparty would be required to post cash collateral to the extent the fair value amount payable to the Partnership exceeds $25.0 million. Additionally, the outstanding derivative contracts contain ratings triggers which would require the Partnership's contracting subsidiary to immediately post collateral in the form of cash or a letter of credit for the full value of any of the derivatives that are in a liability position if the subsidiary's credit rating were reduced below investment grade. At June 30, 2009, the Partnership was not required to post any collateral associated with its derivatives. At June 30, 2009, the Partnership held as cash collateral $5.1 million related to its outstanding derivatives, which was recorded in Other current liabilities. At December 31, 2008, the Partnership held $5.4 million in cash collateral related to its outstanding derivatives.

Note 4: Income Taxes

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

Note 5: Commitments and Contingencies

Calpine Energy Services (Calpine) Settlement

In the first quarter 2008, the Partnership received a cash payment of approximately $15.3 million as settlement of a claim against Calpine and recorded a net gain of $11.2 million related to the realization of the unrecognized portion of the claim which was reported as Contract settlement gain on the Condensed Consolidated Statements of Income.

Legal Proceedings

Napoleonville Salt Dome Matter

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

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

On September 29, 2005, OIL filed suit against Dow Chemical and Dow Hydrocarbon, No. 29,217, in the 23rd Judicial District Court for the Parish of Assumption, State of Louisiana, Oil Insurance Limited v. Dow Chemical Company, et al. OIL seeks indemnification from Dow Hydrocarbon for amounts of insurance paid to Gulf South. Dow Hydrocarbon has filed a demand against OIL and a third-party claim against Gulf South. Dow Hydrocarbon's allegations against Gulf South include contractual violations and liability due to negligence and strict liability. Dow Hydrocarbon seeks recovery for property damage, damages arising from the loss of use of certain wells/caverns and damages incurred responding to and remediating the natural gas leak. Trial of this case has been scheduled to begin in April 2010.

Litigation is subject to many uncertainties, and it is possible these actions could be decided unfavorably. The Partnership expects claims in each of these cases to be covered by insurance that was in place at the time of the incident. For the six month periods ended June 30, 2009 and 2008, the Partnership received $1.4 million and $3.9 million in insurance proceeds related to previously incurred litigation and remediation costs, which were recorded as reductions to Operating Costs and Expenses.

Contract Compliance Review

In October 2008, the Federal Energy Regulatory Commission (FERC) issued an order with respect to an interstate natural gas pipeline not affiliated with the Partnership that redefined what types of changes to a contract within FERC's jurisdiction will be viewed by FERC as a material deviation, thereby requiring that the contract be filed with and approved by FERC. In the fall 2008, the Partnership initiated a review of its transportation and storage contracts for both Gulf South and Texas Gas in order to verify compliance with the order. Based upon the findings of this review, the Partnership has reported to FERC that certain of its transportation and storage contracts may not be in compliance with the requirements of the order. The Partnership met with FERC staff to review its findings and discuss additional steps to be taken and does not expect the outcome to have a material impact on its financial condition, results of operations or cash flows.

Other Legal Matters

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.

Expansion Capital Projects

In the first quarter 2009, the Partnership placed in service the remaining compression assets associated with its Southeast Expansion. The Partnership also placed in service its Gulf Crossing Project and Fayetteville and Greenville Laterals. The Partnership is constructing additional compression facilities for its Gulf Crossing Project and Fayetteville and Greenville Laterals, for which the necessary FERC approvals were received in 2009, and which are expected to be placed in service in 2010. Through June 30, 2009, the Partnership spent $744.1 million on the Southeast Expansion, $1.6 billion on the Gulf Crossing Project and $900.6 million on the Fayetteville and Greenville Laterals.

The Partnership is also engaged in Phase III of the Western Kentucky Storage Expansion project, which consists of developing new working gas capacity at its Midland storage facility for which FERC has granted the Partnership market-based rate authority. A portion of the storage capacity went into service in 2008 and the Partnership has entered into contracts for the remaining capacity to be developed, which is expected to be placed in service in November 2009. Through June 30, 2009, the Partnership spent $56.5 million related to this project.

Environmental and Safety Matters

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

As of June 30, 2009, and December 31, 2008, the Partnership had an accrued liability of approximately $15.8 million and $16.8 million related to assessment and remediation costs associated with the historical use of polychlorinated biphenyls, petroleum hydrocarbons and mercury, enhancement of groundwater protection measures and other costs. The expenditures are expected to occur over approximately the next ten years. The accrual represents management’s estimate of the undiscounted future obligations based on evaluations and discussions with counsel and operating personnel and the current facts and circumstances related to these matters. As of June 30, 2009, and December 31, 2008, approximately $3.5 million was recorded in Other current liabilities and approximately $12.3 million and $13.3 million were recorded in Other Liabilities and Deferred Credits.

Commitments

The Partnership’s future capital commitments are comprised of binding commitments under purchase orders for materials ordered but not received and firm commitments under binding construction agreements. These commitments as of June 30, 2009, were approximately (in millions):

Less than 1 year	$137.1
1-3 years	1.1
4-5 years	-
More than 5 years	-
Total	$138.2

There were no substantial changes to the Partnership’s operating lease commitments or pipeline capacity agreements disclosed in Note 3 to the Partnership’s 2008 Annual Report on Form 10-K.

Note 6: Cash Distributions and Net Income per Unit

Cash Distributions

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

	Total Quarterly Distribution	Marginal Percentage Interest in Distributions	
	Target Amount	Limited Partner Unitholders (1)	General Partner and IDRs
First Target Distribution	up to $0.4025	98%	2%
Second Target Distribution	above $0.4025 up to $0.4375	85%	15%
Third Target Distribution	above $0.4375 up to $0.5250	75%	25%
Thereafter	above $0.5250	50%	50%

(1) The class B unitholders participate in distributions on a pari passu basis with the Partnership's common units up to $0.30 per unit per quarter. The class B units do not participate in quarterly distributions above $0.30 per unit. The class B units began sharing in income allocations and distributions with respect to the third quarter 2008.

In the second quarter 2009, the Partnership paid quarterly distributions to its common unitholders of record of $0.485 per common unit, $0.30 per class B unit to the holder of the class B units and amounts to the general partner on behalf of its 2% general partner interest and as holder of the IDRs. In the second quarter 2008, the Partnership paid quarterly distributions to unitholders of record, including common and subordinated units, of $0.465 per common unit and amounts to the general partner on behalf of its 2% general partner interest and as holder of the IDRs.

In July 2009, the Partnership declared a quarterly cash distribution to unitholders of record of $0.49 per common unit.

Net Income per Unit

In the first quarter 2009, the Partnership began applying the provisions of Emerging Issues Task Force (EITF) Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4) which provides that net income for the current period be reduced by the amount of available cash that will be distributed with respect to that period for purposes of calculating net income per unit. Any residual amount representing undistributed net income (or losses) is assumed to be allocated to the various ownership interests in accordance with the contractual provisions of the partnership agreement.

Under the Partnership's partnership agreement, for any quarterly period, the IDRs participate in net income only to the extent of the amount of cash distributions actually declared, thereby excluding the IDRs from participating in undistributed net income or losses. Accordingly, undistributed net income is assumed to be allocated to the other ownership interests on a pro rata basis, except that the class B units' participation in net income is limited to $0.30 per unit per quarter. Payments made on account of the Partnership's various ownership interests are determined in relation to actual declared distributions, and are not based on the assumed allocations required by EITF No. 07-4.

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and class B units for purposes of computing net income per unit for the three months ended June 30, 2009 (in millions, except per unit data):

	Total	Common Units	Class B Units	General Partner and IDRs
Net income	$20.3			
Declared distribution	91.3	$79.1	$6.9	$5.3
Assumed allocation of undistributed net loss	(71.0)	(60.7)	(8.9)	(1.4)
Assumed allocation of net income	$20.3	$18.4	$(2.0)	$3.9
Weighted average units outstanding		155.5	22.9	
Net income per unit		$0.12	$(0.09)	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and class B units for purposes of computing net income per unit for the six months ended June 30, 2009 (in millions, except per unit data):

	Total	Common Units	Class B Units	General Partner and IDRs
Net income	$72.3			
Declared distribution	178.2	$154.4	$13.7	$10.1
Assumed allocation of undistributed net loss	(105.9)	(90.5)	(13.3)	(2.1)
Assumed allocation of net income	$72.3	$63.9	$0.4	$8.0
Weighted average units outstanding		155.2	22.9	
Net income per unit		$0.41	$0.02	

As a result of applying the provisions of EITF No. 07-04, net income per unit for the three and six months ended June 30, 2008, has been retrospectively adjusted from $0.49 and $1.09 per common and subordinated unit, as originally reported using the provisions of EITF Issue No. 03-06, Participating Securities and the Two-Class Method under FASB Statement No. 128, to $0.50 and $1.18 per common unit and $0.46 and $1.14 per subordinated unit for the three and six months ended June 30, 2008. The following table provides a reconciliation of net income and the assumed allocation of net income to the common and subordinated units for purposes of computing net income per unit for the three months ended June 30, 2008 (in millions, except per unit data):

	Total	Common Units	Subordinated Units	General Partner and IDRs
Net income	$64.7			
Declared distribution	66.2	$47.3	$ 15.6	$3.3
Assumed allocation of undistributed net loss	(1.5)	(1.1)	(0.4)	-
Assumed allocation of net income	$64.7	$46.2	$ 15.2	$3.3
Weighted average units outstanding		92.3	33.1	
Net income per unit		$0.50	$ 0.46	

The following table provides a reconciliation of net income and the assumed allocation of net income to the common and subordinated units for purposes of computing net income per unit for the six months ended June 30, 2008 (in millions, except per unit data):

	Total	Common Units	Subordinated Units	General Partner and IDRs
Net income	$152.8			
Declared distribution	126.7	$89.5	$ 30.9	$6.3
Assumed allocation of undistributed net income	26.1	18.8	6.8	0.5
Assumed allocation of net income	$152.8	$108.3	$ 37.7	$6.8
Weighted average units outstanding		91.5	33.1	
Net income per unit		$1.18	$ 1.14	

Note 7: Financing

Notes and Debentures

As of June 30, 2009, and December 31, 2008, the weighted-average interest rate of the Partnership's notes and debentures was 5.89%. The indentures governing the notes and debentures have restrictive covenants which provide that, with certain exceptions, neither the Partnership nor any of its subsidiaries may create, assume or suffer to exist any lien upon any property to secure any indebtedness unless the debentures and notes shall be equally and ratably secured. All debt obligations are unsecured. At June 30, 2009, Boardwalk Pipelines and its operating subsidiaries were in compliance with their debt covenants.

Long Term Debt - Affiliate

On May 1, 2009, Boardwalk Pipelines entered into a Subordinated Loan Agreement with BPHC under which Boardwalk Pipelines could borrow up to $200.0 million (Subordinated Loans). Boardwalk Pipelines borrowed $100.0 million of Subordinated Loans in May 2009 and borrowed the remaining $100.0 million of Subordinated Loans in June 2009, all of which proceeds were used to fund a portion of the cost of the Partnership's expansion projects and to reduce borrowings under its revolving credit facility described below. The Subordinated Loans bear interest at 8.00% per year, payable semi-annually in June and December, commencing December 2009, and mature six months after the maturity (including any term-out option period) of the revolving credit facility. The Subordinated Loans must be prepaid with the net cash proceeds from the issuance of additional equity securities by the Partnership or the incurrence of certain indebtedness by the Partnership or its subsidiaries although BPHC may waive such prepayment. The Subordinated Loans are subordinated in right of payment to the Partnership's obligations under its revolving credit facility pursuant to the terms of a Subordination Agreement between BPHC and Wachovia Bank, National Association, as representative of the lenders under the revolving credit facility.

Revolving Credit Facility

The Partnership has a revolving credit facility which has aggregate lending commitments of $1.0 billion. A financial institution which has a $50.0 million commitment under the revolving credit facility filed for bankruptcy protection in 2008 and has not funded its portion of the Partnership's borrowing requests since that time. Borrowings outstanding under the credit facility as of June 30, 2009, and December 31, 2008, were $703.5 million and $792.0 million with a weighted-average borrowing rate of 0.58% and 3.43%. Through July 31, 2009, the Partnership had borrowed an additional $50.0 million against the revolver, increasing its borrowings to $753.5 million.

The credit facility contains various restrictive covenants and other usual and customary terms and conditions, including limitations on the payment of cash dividends by its subsidiaries and other restricted payments, the incurrence of additional debt, the sale of assets, and sale-leaseback transactions. The financial covenants under the credit facility require the Partnership and its subsidiaries to maintain, among other things, a ratio of total consolidated debt to consolidated EBITDA (as defined in the credit agreement) measured for the previous twelve months, of not more than 5.0 to 1.0. The Partnership and its subsidiaries were in compliance with all covenant requirements under the credit facility as of June 30, 2009. The revolving credit facility has a maturity date of June 29, 2012.

Offerings of Common Units

For the six months ended June 30, 2009 and 2008, the Partnership completed the following equity offerings, the proceeds of which were used to finance a portion of the Partnership's expansion projects and to repay amounts borrowed under the revolving credit facility (in millions, except the offering price):

Month of Offering	Number of Common Units	Offering Price	Underwriting Discounts and Expenses		Net Proceeds (including General Partner Contribution)	Common Units Outstanding After Offering		Common Units Held by the Public After Offering
June 2009 (a)	6.7	$ 21.99	$ -	(b)	$ 150.0	161.6	(c)	47.4
June 2008	10.0	25.30	9.4		248.8	100.7		47.4

(a) Sold to BPHC in a private placement. BPHC waived the mandatory prepayment of the Subordinated Loans with the net proceeds of this private placement.
(b) Pursuant to the Registration Rights Agreement discussed below, the Partnership agreed to reimburse certain future underwriting discounts and expenses that may be incurred by BPHC upon a resale of these units.
(c) Includes the conversion of all of the 33.1 million subordinated units into common units in November 2008.

Class B Units

In June 2008, the Partnership issued and sold, pursuant to the Class B Unit Purchase Agreement, approximately 22.9 million of class B units representing limited partner interests (class B units) to BPHC for $30.00 per class B unit, or an aggregate purchase price of $686.0 million. The Partnership's general partner also contributed $14.0 million to the Partnership to maintain its 2% interest. The Partnership used the proceeds of $700.0 million to repay amounts borrowed under the revolving credit facility and to fund a portion of the costs of its ongoing expansion projects. The class B units are convertible into common units by the holder on a one-for-one basis at any time after June 30, 2013. The class B units began sharing in income allocations and distributions with respect to the third quarter 2008.

Registration Rights Agreement

The Partnership has entered into an Amended and Restated Registration Rights Agreement with BPHC under which the Partnership has agreed to register the resale by BPHC of the common units acquired by BPHC in June 2009 and October 2008 and the common units to be acquired upon conversion of the class B Units. The Partnership also agreed to pay the expenses, including accounting and legal expenses, incurred by BPHC in the sale of such securities and to reimburse BPHC for any underwriting discounts and commissions on the sale by BPHC of certain of such common units. In connection with the June 2009 private placement of common units to BPHC, this agreement was amended to increase the number of units for which the Partnership has agreed to reimburse BPHC for underwriting discounts and commissions from 21.2 million to 27.9 million, up to a maximum of $0.914 per common unit. As of June 30, 2009 and December 31, 2008, the Partnership had an accrued liability of approximately $26.7 million and $20.6 million as a result of the contingent obligation to BPHC.

Note 8: Property, Plant and Equipment

In 2009, the Partnership placed in service its Gulf Crossing Project and Fayetteville and Greenville Laterals and the remaining compression facilities associated with its Southeast Expansion project. As a result, approximately $2.3 billion was transferred from work in progress to plant. The assets will generally be depreciated over a term of 35 years.

Note 9: Employee Benefits

Defined Benefit Plans

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

Components of net periodic benefit cost for both the retirement plans and postretirement benefits other than pension (PBOP) for the three and six months ended June 30, 2009 and 2008 were the following (in millions):

	Retirement Plans For the Three Months Ended June 30,		PBOP For the Three Months Ended June 30,	
	2009	2008	2009	2008
Service cost	$0.9	$0.9	$0.1	$0.1
Interest cost	1.7	1.6	0.7	0.8
Expected return on plan assets	(1.4)	(1.7)	(0.7)	(1.2)
Amortization of prior service credit	-	-	(1.9)	(1.9)
Amortization of unrecognized net loss	0.5	-	0.4	-
Regulatory asset decrease	-	-	1.3	1.3
Net periodic pension expense	$1.7	$0.8	$(0.1)	$(0.9)

	Retirement Plans For the Six Months Ended June 30,		PBOP For the Six Months Ended June 30,	
	2009	2008	2009	2008
Service cost	$1.8	$1.8	$0.2	$0.3
Interest cost	3.4	3.2	1.5	1.6
Expected return on plan assets	(2.7)	(3.3)	(1.7)	(2.5)
Amortization of prior service credit	-	-	(3.8)	(3.9)
Amortization of unrecognized net loss	0.9	-	0.7	0.1
Regulatory asset decrease	-	-	2.7	2.7
Net periodic pension expense	$3.4	$1.7	$(0.4)	$(1.7)

Defined Contribution Plans

Texas Gas employees hired on or after November 1, 2006, and Gulf South employees are provided retirement benefits under a defined contribution money purchase plan. The operating subsidiaries also provide 401(k) plan benefits to their employees. Costs related to the Partnership's defined contribution plans were $1.6 million and $3.3 million for the three and six months ended June 30, 2009 and $1.5 million and $3.1 million for the three and six months ended June 30, 2008.

Note 10: Related Party Transactions

Loews provides a variety of corporate services to the Partnership and its subsidiaries under services agreements which have been operative since the Partnership's initial public offering. Services provided by Loews include, among others, information technology, tax, risk management, internal audit and corporate development services. Loews charged $3.9 million and $7.8 million for the three and six months ended June 30, 2009, and $3.4 million and $7.5 million for the three and six months ended June 30, 2008, to the Partnership for performing these services, plus related expenses and allocated overheads.

Distributions paid related to limited partner units held by BPHC, the 2% general partner interest and IDRs held by Boardwalk GP were $126.9 million and $85.5 million for the six months ended June 30, 2009 and 2008.

In addition to these transactions, in the second quarter 2009, Boardwalk Pipelines entered into and borrowed $200.0 million from BPHC under a Subordinated Loan Agreement and the Partnership issued and sold 6.7 million common units to BPHC. Note 7 contains more information regarding these transactions.

Note 11: Accumulated Other Comprehensive Income (Loss)

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

	As of June 30, 2009	As of December 31, 2008
Loss on cash flow hedges	$ (0.7)	$ (0.7)
Deferred components of net periodic benefit cost	(19.7)	(14.8)
Total Accumulated other comprehensive loss	$ (20.4)	$ (15.5)

Note 12: Guarantee of Securities of Subsidiaries

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

The Partnership's subsidiaries have no significant restrictions on their ability to pay distributions or make loans to the Partnership except as noted in the debt covenants and had no restricted assets at June 30, 2009. Note 7 contains additional information regarding the Partnership's debt and related covenants.

Note 13: Financial Instruments

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

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

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

At December 31, 2008, the portfolio consisted of $175.0 million of Treasury securities with original maturities in August 2009, held pursuant to overnight repurchase agreements. The amount invested under repurchase agreements was stated at fair value based on quoted market prices for the securities. The Partnership had no short- term investments at June 30, 2009.

Long-Term Debt: Except for debt issued by Gulf South, the debt issued by Texas Gas in March 2008, the revolving credit facility and the Subordinated Loans categorized as Long-Term Debt - Affiliate, all of the Partnership's long-term debt is publicly traded. The estimated fair value of the Partnership's publicly traded debt is based on quoted market prices at June 30, 2009 and December 31, 2008. The fair market value of the debt that is not publicly traded is based on market prices of similar debt at June 30, 2009 and December 31, 2008.

Long-Term Debt - Affiliate: Borrowings under the Subordinated Loans were completed in May and June 2009. The estimated fair value is based on market prices of similar debt, adjusted for the affiliated nature of the transaction. Note 7 contains more information regarding the Subordinated Loans.

The carrying amount and estimated fair values of the Partnership's financial instruments as of June 30, 2009 and December 31, 2008 were as follows (in millions):

	June 30, 2009		December 31, 2008	
Financial Assets	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$71.8	$71.8	$137.7	$137.7
Short-term investments	$-	$-	$175.0	$175.0
Financial Liabilities				
Long-term debt	$2,801.9	$2,687.5	$2,889.4	$2,655.3
Long-term debt – affiliate	$200.0	$210.0	$-	$-

Item 2. 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 accompanying interim condensed consolidated financial statements, related notes and Risk Factors, included elsewhere in this report and prepared in accordance with accounting principles generally accepted in the United States of America and our consolidated financial statements, related notes, Management's Discussion and Analysis of Financial Condition and Results of Operations and Risk Factors included in our Annual Report on Form 10-K for the year ended December 31, 2008.

Overview

Through our subsidiaries, Gulf Crossing Pipeline Company LLC (Gulf Crossing), Gulf South Pipeline Company, LP (Gulf South) and Texas Gas Transmission, LLC (Texas Gas) (collectively, the operating subsidiaries), we own and operate three interstate natural gas pipeline systems including integrated storage facilities. Our pipeline systems originate in the Gulf Coast region and extend northeasterly to the Midwestern states of Tennessee, Kentucky, Illinois, Indiana and Ohio. As of June 30, 2009, Boardwalk Pipelines Holding Corp. (BPHC), a wholly-owned subsidiary of Loews Corporation (Loews) owned 114.2 million of our common units, all 22.9 million of our class B units and, through Boardwalk GP, LP (Boardwalk GP), an indirect wholly-owned subsidiary of BPHC, holds the 2% general partner interest and all of the incentive distribution rights (IDRs). As of June 30, 2009, the common units, class B units and general partner interest owned by BPHC represent approximately 75% of our equity interests, excluding the IDRs. Our common units are traded under the symbol “BWP” on the New York Stock Exchange.

Our transportation services consist of firm transportation, whereby the customer pays a capacity reservation charge to reserve pipeline capacity at certain receipt and delivery points along our pipeline systems, plus a commodity and fuel charge on the volume of natural gas actually transported, and interruptible transportation, whereby the customer pays to transport gas only when capacity is available and used. We offer firm storage services in which the customer reserves and pays for a specific amount of storage capacity, including injection and withdrawal rights, and interruptible storage and parking and lending (PAL) services where the customer receives and pays for capacity only when it is available and used. Some PAL agreements are paid for at inception of the service and revenues for these agreements are recognized as service is provided over the term of the agreement. Our operating costs and expenses typically do not vary significantly based upon the amount of gas transported, with the exception of fuel consumed at our compressor stations, which is included in Fuel and gas transportation expenses on our Condensed Consolidated Statements of Income.

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

Expansion Projects

During the first quarter 2009, we placed in service the remaining pipeline assets and the initial compression assets associated with our major pipeline expansion projects. Each of these projects is now transporting natural gas. Additional compression facilities will be constructed in 2010 on the Gulf Crossing Pipeline and the Fayetteville and Greenville Laterals to increase the peak-day delivery capacities of those projects.

Remediation of Pipe Anomalies

As previously reported, we are seeking authority from the Pipeline and Hazardous Materials Safety Administration (PHMSA) to operate our new expansion pipeline projects under special permits that would allow each pipeline to operate at higher than normal operating pressures (80% of the pipe's Specified Minimum Yield Strength, or SMYS, as opposed to the normal operating pressure of 72% SMYS), thereby increasing its maximum peak-day transmission capacity. For each expansion pipeline, we have entered into firm transportation contracts with shippers which would utilize the maximum capacity available from operating at higher operating pressures.

During the permitting process we discovered anomalies in certain pipeline segments on each of our expansion projects. Accordingly, we reduced the operating pressures on each pipeline below normal operating pressures as we proceed to perform additional testing procedures, remediate the anomalies and seek authority from PHMSA to increase operating pressures, first to normal operating pressures and subsequently to higher operating pressures under the special permit. We have also shut down pipeline segments for periods of time to remediate anomalies. We entered into an agreement with PHMSA during the second quarter 2009 which modified each of our special permits that define the testing protocol and remediation efforts, including replacement of certain pipe joints, performing investigative digs to physically inspect the pipe sections and conducting metallurgical testing and analysis on a variety of pipe samples.

The pressure reductions and shutdowns that have been undertaken to remediate anomalies on our expansion pipeline projects have reduced throughput and adversely impacted our transportation revenues, net income and cash flow. At the same time, our operating costs and expenses, particularly depreciation and property taxes, have increased due to costs associated with the expansion project pipelines being placed into service. See Results of Operations below for more information on the financial impacts of the pressure reductions and shutdowns.

With respect to each of our expansion pipelines, until we have remediated the pipe anomalies, performed additional testing required by PHMSA and obtained PHMSA's consent to increase operating pressures to normal levels, as well as higher levels under special permits, we will not be able to operate that pipeline at its anticipated peak-day transmission capacity, which could continue to have a material adverse affect on our business, financial condition, results of operations and cash flow, including our ability to make distributions to unitholders. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher operating pressures. See Item 1A, Risk Factors – A portion of the expected maximum daily capacity of our pipeline expansion projects is contingent on our receiving and maintaining authority from PHMSA to operate at higher operating pressures.

Set forth below is information with respect to the status of each of our four pipeline expansion projects as of July 31, 2009. Expected transportation revenue is based on the projected reservation charges under firm contracts.

East Texas Pipeline. Portions of this pipeline were shut down for periods of time in May and July 2009, during which time we completed the requisite anomaly remediation. Effective July 27, 2009, we received authority from PHMSA to operate the East Texas pipeline at normal operating pressures which resulted in peak-day transmission capacity for this pipeline of approximately 1.4 billion cubic feet (Bcf) per day. If additional testing is successful, we expect to request permission from PHMSA to operate this pipeline under a special permit at higher operating pressures which would increase peak-day transmission capacity by approximately 50.0 million cubic feet per day.

Southeast Expansion. Portions of this pipeline were shut down for periods of time in May and July 2009, during which time we completed the requisite anomaly remediation. Effective July 27, 2009, we received authority from PHMSA to operate the Southeast expansion pipeline at normal operating pressures which resulted in peak-day transmission capacity for this pipeline of approximately 1.6 Bcf per day. If additional testing is successful, we expect to request permission from PHMSA to operate this pipeline under a special permit at higher operating pressures which would increase peak-day transmission capacity to approximately 1.9 Bcf per day.

Gulf Crossing Project. The Gulf Crossing Project was shut down the entire month of June, during which time we completed the requisite anomaly remediation. Effective July 1, 2009, we received authority from PHMSA to operate the Gulf Crossing Project at normal operating pressures which resulted in peak-day transmission capacity for this pipeline of approximately 1.2 Bcf per day. If additional testing is successful, we expect to request permission from PHMSA to operate this pipeline under a special permit at higher operating pressures which would increase peak-day transmission capacity to approximately 1.4 Bcf per day. We expect to further increase peak-day transmission capacity to approximately 1.7 Bcf per day, assuming we have received authority to operate under a special permit, by adding compression in 2010.

Fayetteville and Greenville Laterals. We are continuing to test the Fayetteville and Greenville Laterals for anomalies. We have run a high resolution deformation tool on these pipelines and, based on preliminary test results, believe there are anomalies in approximately 1% of the pipeline joints. We are working with PHMSA on a remediation protocol to be adopted to return these pipelines to normal operating pressures. We cannot predict when this protocol will be completed and if it will be approved by PHMSA. Currently the Fayetteville Lateral is transporting approximately 0.6 Bcf per day and the Greenville Lateral is currently transporting approximately 0.3 Bcf per day. If we receive authority from PHMSA to operate the Fayetteville and Greenville Laterals at normal operating pressures, the Fayetteville and Greenville Laterals will each have peak-day transmission capacities of approximately 0.8 Bcf per day. If additional testing is successful, we expect to request permission from PHMSA to operate the Fayetteville Lateral under special permits at higher operating pressures which would enable it to transport up to approximately 1.0 Bcf per day. In addition, we plan to add compression in 2010 that will increase peak-day delivery capacities to approximately 1.0 Bcf per day on the Greenville Lateral, and assuming the Fayetteville Lateral is operating at the higher operating pressures, increase peak-day delivery capacities to approximately 1.3 Bcf per day on the Fayetteville Lateral. During the second quarter 2009, we replaced the portion of the Fayetteville Lateral consisting of 18-inch diameter pipe running under the Little Red River in Arkansas with 36-inch diameter pipe, thus completing this river crossing.

Assuming we operate the expansion pipelines on an uninterrupted basis at normal operating pressures and based on the current level of reservation charges under firm contracts, transportation revenues from those projects would be approximately $4.0 million per month less in the aggregate than if those pipelines had operated at the higher operating pressures contemplated. This shortfall would increase over time as volumes increase under our existing firm contracts and compression is added to these projects, as planned.

Other

In addition to the projects previously described, we are continuing with efforts to expand our Gulf South system in the Haynesville production area in Louisiana. This expansion, which we anticipate will be in service in late 2010, consists of adding compression at an expected cost of approximately $185.0 million, subject to the Federal Energy Regulatory Commission (FERC) approval. Customers have contracted for approximately 0.4 Bcf per day of capacity on this project which will be able to be delivered at normal operating pressures.

We are also engaged in Phase III of our Western Kentucky Storage Expansion project, which consists of developing approximately 8.3 Bcf of new storage capacity. We have placed in service approximately 5.4 Bcf of new working gas capacity and we expect to place the remaining working gas capacity into service in November 2009. We expect this project to cost approximately $87.7 million, of which we have spent approximately $56.5 million as of June 30, 2009.

Due to the substantial completion of construction on the expansion projects, our materials and supplies inventory, most of which is included in Other Assets on our balance sheets, has increased. We are in the process of evaluating the level of inventory required to support our ongoing operations and growth projects and expect this review to be completed in 2009.

Results of Operations for the Three Months Ended June 30, 2009 and 2008

Our net income for the second quarter 2009, decreased $44.4 million, or 69%, to $20.3 million compared to $64.7 million for the second quarter 2008. Operating expenses for the second quarter 2009 were higher than the comparable period in 2008, mainly as a result of increases in depreciation and property taxes associated with our expansion projects. The increase in expenses more than offset the increase in revenues from our expansion projects, which were approximately $58.0 million lower than expected due to operating our expansion pipelines at reduced operating pressures and portions of the expansion pipelines being shut down for periods of time during the second quarter 2009, as discussed under Expansion Projects. The 2008 period was favorably impacted by $18.8 million of gains on sales of natural gas and mark-to-market derivative activity associated with our expansion projects.

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Operating revenues for the second quarter 2009, increased $11.1 million, or 6%, to $201.4 million, compared to $190.3 million for the second quarter 2008. Gas transportation revenues, excluding fuel, increased $31.2 million, primarily from our expansion projects. PAL revenues increased $3.8 million due to favorable summer-to-summer natural gas price spreads. These increases were partially offset by lower fuel revenues of $24.7 million due to unfavorable natural gas prices.

Operating costs and expenses for the second quarter 2009, increased $38.9 million, or 36%, to $148.2 million, compared to $109.3 million for the second quarter 2008. The primary factors for the increases were higher depreciation and property taxes of $29.7 million associated with an increase in our asset base. Operations and maintenance expense increased $6.7 million due to maintenance projects and expansion project operations. Pipeline investigation and retirement costs related to the East Texas Pipeline, which impacted operations and maintenance expenses and loss on disposal of assets, were approximately $3.6 million. Administrative and general expense increased $3.3 million due to increases in unit-based compensation from an increase in the price of our common units, and employee benefits as a result of reductions in trust assets for our pension and post-retirement benefit plans driven by investment losses. The 2008 period was favorably impacted by a $14.7 million gain on the sale of gas related to the Western Kentucky Storage Expansion project. Fuel and gas transportation expenses decreased $20.4 million primarily as a result of lower natural gas prices.

Total other deductions increased by $16.8 million, or 104%, to $32.9 million for the second quarter 2009, compared to $16.1 million for the 2008 period. The primary factor for the increase was higher interest expense of $15.3 million resulting from lower capitalized interest associated with placing expansion projects in service and higher debt levels in 2009. The 2008 period included $4.1 million of gains from the mark-to-market effect of derivatives associated with the purchase of line pack for our expansion projects.

Results of Operations for the Six Months Ended June 30, 2009 and 2008

Our net income for the first six months of 2009 decreased $80.5 million, or 53%, to $72.3 million compared to $152.8 million from the comparable period in 2008. Although revenues for the six month period ended June 30, 2009, were higher than the comparable period for 2008, the increase was more than offset by increased operating expenses, mainly as a result of increased depreciation and property taxes due to an increase in our asset base associated with our expansion projects. Transportation revenues from expansion projects, excluding fuel, were approximately $70.0 million lower than expected due to operating our expansion pipelines at reduced operating pressures and portions of the expansion pipelines being shut down for periods of time during the second quarter 2009. The 2008 period was favorably impacted by gains of $33.1 million related to the sale of gas from the Western Kentucky Storage Expansion project, a contract settlement and mark-to-market derivative activity associated with our expansion projects.

Operating revenues for the six months ended June 30, 2009, increased $37.2 million, or 10%, to $424.8 million, compared to $387.6 million for the six months ended June 30, 2008. Gas transportation revenues, excluding fuel, increased $59.6 million primarily due to our expansion projects. PAL revenues increased $6.1 million as a result of favorable winter-to-summer natural gas price spreads and gas storage revenues increased $3.6 million related to an increase in storage capacity associated with our Western Kentucky Storage Expansion project. These increases were partially offset by lower fuel revenues of $32.2 million due to lower natural gas prices.

Operating costs and expenses for the six months ended June 30, 2009, increased $87.9 million, or 43%, to $293.0 million, compared to $205.1 million for the six months ended June 30, 2008. The primary drivers were increased depreciation and property taxes of $59.3 million associated with an increase in our asset base due to expansion. Operations and maintenance expense increased $11.6 million due to major maintenance projects and expansion project operations. Administrative and general expense increased $7.0 million due to increases in outside services, unit-based compensation from an increase in the price of our common units and employee benefits as a result of reductions in trust assets for our pension and post-retirement benefit plans driven by investment losses. Pipeline investigation and retirement costs related to the East Texas Pipeline, which impacted operations and maintenance expenses and loss on disposal of assets, were approximately $4.1 million. The 2008 period was favorably impacted by a $14.7 million gain on the sale of gas related to the Western Kentucky Storage Expansion project and an $11.2 million gain from the settlement of a contract claim. Fuel and gas transportation expenses decreased $20.6 million primarily as a result of reduced natural gas prices.

Total other deductions increased by $30.0 million, or 103%, to $59.2 million for the six months ended June 30, 2009, compared to $29.2 million for the 2008 period as a result of lower capitalized interest associated with placing our expansion projects in service and increased debt levels in 2009. The 2008 period included gains of $7.2 million related to mark-to-market gains from derivatives associated with the purchase of line pack for our pipeline expansion projects.

Liquidity and Capital Resources

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

Maintenance Capital Expenditures

Maintenance capital expenditures for the six months ended June 30, 2009 and 2008 were $19.7 million and $13.2 million. We expect to fund the remaining 2009 maintenance capital expenditures of approximately $48.1 million from our operating cash flows.

Expansion Capital Expenditures

We have incurred and will continue to incur costs to remediate the pipeline anomalies described under Expansion Projects, including pipe replacement costs associated with our East Texas Pipeline. Additionally, we are still testing portions of the Fayetteville and Greenville Laterals for anomalies, thereby making the full cost of remediating the pipelines unknown. However, we anticipate that the cost to remediate the anomalies will not require us to increase our previously announced estimated total cost to complete our expansion projects. The following table presents the estimated total capital expenditures and the amounts invested through June 30, 2009, for our remaining pipeline expansion projects and the 42-inch pipe remediation efforts (in millions):

	Estimated Total Capital Expenditures (1)	Cash Invested through June 30, 2009
Southeast Expansion	$ 755	$ 744.1
Gulf Crossing Project	1,765	1,581.8
Fayetteville and Greenville Laterals	1,290	900.6
Haynesville Project	185	0.1
42-inch Pipe Remediation (2)	55	10.1
Total	$ 4,050	$ 3,236.7

(1) Our estimated total capital expenditures reflect the latest cost estimates, including those for the 42-inch pipe remediation. These cost estimates are based on internally developed financial models and timelines. Factors in the estimates include, but are not limited to, those related to pipeline costs based on mileage, size and type of pipe, materials and construction and engineering costs.

(2) This estimate represents the cost of remediating our 42-inch pipeline expansion projects, including the East Texas Pipeline, the Southeast Expansion and the Gulf Crossing Project. Testing on the Fayetteville and Greenville Laterals is ongoing, therefore the estimated total capital expenditures related to the Fayetteville and Greenville

Laterals remain unknown at the time of the filing of this Form 10-Q.

We expect to incur additional capital expenditures of approximately $815.0 million to complete our expansion projects. The majority of the expenditures related to our expansion projects, including remediation efforts, are expected to occur in 2009, with the balance to be incurred in 2010. Our cost and timing estimates for these projects are subject to a variety of risks and uncertainties as discussed in Part II, Item 1A, Risk Factors, of this Form 10-Q and Item 1A, Risk Factors, of our Annual Report on Form 10-K for the year ended December 31, 2008.

We have financed our expansion capital costs through the issuance of equity and debt, borrowings under our revolving credit facility and available operating cash flow in excess of our operating needs. We anticipate we will need to finance approximately $350.0 million to complete our expansion projects, which we expect to finance through the issuance of both debt and equity. Our largest unitholder, Loews Corporation, has advised us that it is willing to provide up to an additional $150.0 million of capital to fund these projects to the extent the public markets remain unavailable on acceptable terms. Any additional financing provided by Loews would be subject to review and approval, as to fairness, by our independent Conflicts Committee. Part II, Item 1A, Risk Factors, of this Form 10-Q and Item 1A, Risk Factors, of our Annual Report on Form 10-K for the year ended December 31, 2008, contain more information regarding risks associated with our expansion projects and the related financing.

Equity and Debt Financing

In June 2009, we issued and sold approximately 6.7 million of our common units to BPHC at a price of $21.99 per unit. We received net cash proceeds of approximately $150.0 million, including a $3.0 million contribution received from our general partner to maintain its 2% general partner interest.

In May 2009, Boardwalk Pipelines entered into a Subordinated Loan Agreement with BPHC under which Boardwalk Pipelines could borrow up to $200.0 million (Subordinated Loans). Boardwalk Pipelines borrowed $100.0 million of Subordinated Loans in May 2009 and borrowed the remaining $100.0 million of Subordinated Loans in June 2009, all of which proceeds were used to fund a portion of the cost of our expansion projects and to reduce borrowings under our revolving credit facility described below. The Subordinated Loans bear interest at 8.00% per year, payable semi-annually in June and December, commencing December 2009, and mature six months after the maturity (including any term-out option period) of the revolving credit facility. Note 7 in Item 1 of this report contains further discussion of the Subordinated Loans.

Revolving Credit Facility

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

As of June 30, 2009, borrowings outstanding under our credit facility were $703.5 million with a weighted-average interest rate of 0.58%. Through July 31, 2009, we had borrowed an additional $50.0 million under the credit facility, which increased our borrowings to $753.5 million. We and our subsidiaries are in compliance with all covenant requirements under our credit facility. Note 7 in Item 1 of this report contains further discussion of the revolving credit facility.

Our revolving credit facility contains customary negative covenants, including, among others, limitations on the payment of cash dividends and other restricted payments, the incurrence of additional debt, sale-leaseback transactions and transactions with our affiliates. The facility also contains a financial covenant that requires us and our subsidiaries to maintain a ratio of total consolidated debt to consolidated earnings before income taxes, depreciation and amortization (as defined in the credit agreement), measured for the preceding twelve months, of not more than five to one. Although we do not believe that these covenants have had, or will have, a material impact on our business and financing activities or our ability to obtain the financing to maintain operations and continue our capital investments, they could restrict us in some circumstances as stated in Item 1A, Risk Factors, of our Annual Report on Form 10-K for the year ended December 31, 2008. In particular, maintaining compliance with the financial covenant may limit our ability to incur additional indebtedness to finance our growth projects, which could limit our growth opportunities or require the issuance of more equity securities by us than anticipated.

Distributions

For the six months ended June 30, 2009 and 2008, we paid distributions of $172.6 million and $120.1 million. Note 6 in Part 1, Item 1 of this report contains further discussion regarding our distributions.

Changes in cash flow from operating activities

Net cash provided by operating activities decreased $3.9 million to $167.7 million for the six months ended June 30, 2009, compared to $171.6 million for the comparable 2008 period, primarily due to a decrease of $20.9 million in net income, excluding non-cash items such as depreciation and amortization, and a $32.7 million increase related to inventory purchases and other assets. The decreases of cash were offset by prepayments received under PAL arrangements in the 2009 period and the settlement of derivatives in the 2008 period.

Changes in cash flow from investing activities

Net cash used in investing activities decreased $759.7 million to $322.2 million for the six months ended June 30, 2009, compared to $1,081.9 million for the comparable 2008 period, primarily due to a $592.3 million decrease in capital expenditures related to our expansion projects, and the sale of $175.0 million of short-term investments.

Changes in cash flow from financing activities

Net cash provided by financing activities decreased $987.0 million to $88.6 million for the six months ended June 30, 2009, compared to $1,075.6 million for the comparable 2008 period. These decreases resulted from a $798.5 million reduction in proceeds from the issuance and sale of equity, including related general partner contributions, a $136.0 million decrease in proceeds from the issuance of debt and net borrowings under our revolving credit facility and a $52.5 million increase in distributions to our partners.

Contractual Obligations

The table below is updated for significant changes in contractual cash payment obligations as of June 30, 2009, by period (in millions):

	Total	Less than 1 Year	1-3 Years	4-5 Years	More than 5 Years
Principal payments on long-term debt (1)	$3,013.5	$-	$-	$1,378.5	$1,635.0
Interest on long-term debt (2)	920.9	68.5	266.9	230.4	355.1
Capital commitments (3)	138.2	137.1	1.1	-	-
Total	$4,072.6	$205.6	$268.0	$1,608.9	$1,990.1

(1) Includes our senior unsecured notes, having maturity dates from 2012 to 2027, $703.5 million of loans outstanding under our revolving credit facility, having a maturity date of June 29, 2012, and our Subordinated Loans, which mature on December 29, 2012.

(2) Interest obligations represent interest due on our senior unsecured notes and Subordinated Loans at fixed rates. Future interest obligations under our revolving credit facility are uncertain, due to the variable interest rate and fluctuating balances. Based on a 0.58% weighted-average interest rate on amounts outstanding under our revolving credit facility as of June 30, 2009, $2.0 million, $8.2 million and $2.0 million would be due under the credit facility in less than one year, 1-3 years, and 4-5 years.

(3)

Capital commitments represent binding commitments under purchase orders for materials ordered but not received and firm commitments under binding construction service agreements existing at June 30, 2009. The amounts shown do not reflect commitments we have made after June 30, 2009.

Pursuant to the settlement of the Texas Gas rate case in 2006, we are required to annually fund an amount to the Texas Gas pension plan equal to the amount of actuarially determined net periodic pension cost, including a minimum of $3.0 million. In 2009, we expect to fund approximately $5.0 million to the Texas Gas pension plan.

Off-Balance Sheet Arrangements

At June 30, 2009, we had no guarantees of off-balance sheet debt to third parties, no debt obligations that contain provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings, and no other off-balance sheet arrangements.

Critical Accounting Policies

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

During the second quarter 2009, there were no significant changes to our critical accounting policies, judgments or estimates disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008.

Forward-Looking Statements

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

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond our control that could cause actual results to differ materially from those anticipated or projected. These risks and uncertainties include, among others:

- A portion of the transportation capacity on each of our expansion project pipelines that we expect will ultimately be available is contingent upon our receipt of authority to operate each of our pipeline expansion projects at higher operating pressures under a special permit issued by PHMSA. To the extent that PHMSA does not grant us authority to operate any of our expansion pipelines under a special permit or withdraws previously granted authority to operate under a special permit, transportation capacity made available to the market and transportation revenues received in the future would be reduced.

- The successful completion, timing, cost, scope and future financial performance of our expansion projects could differ materially from our expectations due to anomalies or defects in pipe segments, availability of contractors or equipment, ground conditions, weather, difficulties or delays in obtaining regulatory approvals or denied applications, land owner opposition, the lack of adequate materials, labor difficulties or shortages and numerous other factors beyond our control.

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

- Global financial markets and economic conditions have been, and continue to be, experiencing extraordinary disruption and volatility following adverse changes in global capital markets. The cost of raising money in the debt and equity capital markets and commercial credit markets has increased substantially while the availability of funds from those markets has diminished significantly.

- Our FERC gas tariffs only allow us to require limited credit support in the event that our transportation customers are unable to pay for our services. If any of our significant customers have credit or financial problems which result in a delay or failure to pay for services provided by us, or contracted for with us, or repay the gas they owe us, it could adversely affect our business, financial condition and results of operations.

- The gas transmission and storage operations of our subsidiaries are subject to rate-making policies and actions by FERC or customers that could have an adverse impact on the services we offer and the rates we charge and our ability to recover the full cost of operating our pipelines, including earning a reasonable return.

- We are subject to laws and regulations relating to our rates and how we provide jurisdictional transportation services, the environment and pipeline operations which may expose us to significant costs, liabilities and loss of revenues. Any changes in such regulations or their application generally or through enforcement actions could adversely affect our business, financial condition and results of operations. In addition, any new legislation that creates new requirements, for example, greenhouse gases, or modifies long-standing regulatory policies could have a material impact on our business.

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

- The cost of insuring our assets may increase dramatically.

- Because of the natural decline in gas production connected to our system, our success depends on our ability to obtain access to new sources of natural gas, which is dependent on factors beyond our control. Any decrease in supplies of natural gas in our supply areas could adversely affect our business, financial condition and results of operations.

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

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

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Interest rate risk:

With the exception of our revolving credit facility, for which the interest rate is reset each quarter, our debt has been issued at fixed rates. For fixed-rate debt, changes in interest rates affect the fair value of the debt instruments but do not directly affect earnings or cash flows. The following table presents market risk associated with our fixed-rate long-term debt at June 30, 2009, and December 31, 2008 (in millions, except interest rates):

	June 30, 2009	December 31, 2008
Carrying value of fixed-rate debt	$ 2,298.4	$ 2,097.4
Fair value of fixed-rate debt	$ 2,194.0	$ 1,863.3
100 basis point increase in interest rates and resulting debt decrease	$ 116.4	$ 117.1
100 basis point decrease in interest rates and resulting debt increase	$ 124.7	$ 126.1
Weighted-average interest rate	6.07 %	5.89 %

At June 30, 2009, we had $703.5 million outstanding under our revolving credit agreement at a weighted- average interest rate of 0.58%, which rate is reset approximately each quarter. A 1% increase or decrease in interest rates would increase or reduce our cash payments for interest on the credit facility by $7.0 million on an annual basis. At December 31, 2008, we had $792.0 million outstanding under our revolving credit facility.

At June 30, 2009, and December 31, 2008, $71.8 million and $137.7 million of our undistributed cash, shown on the balance sheets as Cash and cash equivalents, were invested primarily in Treasury fund accounts and at December 31, 2008, $175.0 million was invested in U.S. Treasury notes under repurchase agreements and shown as Short-term investments. Due to the short-term nature of the Treasury fund accounts, a hypothetical 10% increase or decrease in interest rates would not have a material effect on the fair market value of our Cash and cash equivalents.

Commodity risk:

Certain volumes of our gas stored underground are available for sale and subject to commodity price risk. At June 30, 2009, and December 31, 2008, approximately $1.7 million and $0.2 million of gas stored underground, which we own and carry as current Gas stored underground, was available for sale and exposed to commodity price risk. Additionally, 3.3 Bcf of gas with a book value of $7.5 million has become available for sale as a result of Phase III of the Western Kentucky Storage Expansion. We utilize derivatives to hedge certain exposures to market price fluctuations on the anticipated operational sales of gas. Our pipelines do not take title to the natural gas which they transport and store in rendering traditional firm and interruptible storage services, therefore they do not assume the related natural gas commodity price risk associated with that gas.

The derivatives related to the sale of natural gas and cash for fuel reimbursement qualify for cash flow hedge accounting under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, as amended, and are designated as such. The effective component of related gains and losses resulting from changes in fair values of the derivatives contracts designated as cash flow hedges are deferred as a component of Accumulated other comprehensive (loss) income. The deferred gains and losses are recognized in earnings when the anticipated transactions affect earnings.

Credit risk:

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

As of June 30, 2009, the amount of gas loaned out under PAL agreements and the amount of gas owed to the operating subsidiaries due to gas imbalances was approximately 18.9 trillion British thermal units (TBtu). Assuming an average market price during June 2009 of $3.67 per million British thermal unit (MMBtu), the market value of that gas was approximately $69.4 million. As of December 31, 2008, the amount of gas loaned out under PAL agreements and the amount of gas owed to the operating subsidiaries due to gas imbalances was approximately 34.4 TBtu. Assuming an average market price during December 2008 of $5.85 per MMBtu, the market value of this gas at December 31, 2008, would have been approximately $201.2 million.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

Our principal executive officer (CEO) and principal financial officer (CFO) undertook an evaluation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act")) as of the end of the period covered by this report. The CEO and CFO have concluded that our disclosure controls and procedures were effective as of June 30, 2009.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that occurred during the quarter ended June 30, 2009, that have materially affected or that are reasonably likely to materially affect our internal control over financial reporting.

PART II – OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of certain of our current legal proceedings, please read Note 5 of the Notes to Condensed Consolidated Financial Statements in Item 1 of this Report.

Item 1A. Risk Factors

Our Annual Report on Form 10-K for the year ended December 31, 2008 includes a detailed discussion of certain material risk factors facing us. The risk factors below have been restated in their entirety from the information disclosed in our Form 10-K and should be read in conjunction with the other risk factors and information disclosed in our Form 10-K.

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

We are seeking authority from PHMSA to operate our new expansion pipeline projects under special permits that would allow each pipeline to operate at higher than normal operating pressures (80% of the pipe's Specified Minimum Yield Strength, or SMYS, as opposed to the normal operating pressure of 72% SMYS). The ability to operate at higher operating pressures increases the transportation capacity of the pipelines, thereby increasing its maximum peak-day transmission capacity. For each expansion pipeline, we have entered into firm transportation contracts with shippers which would utilize the maximum capacity available from operating at higher operating pressures. Therefore, absent such authority, we will not be able to transport all of the contracted quantities of natural gas on these pipelines.

During the permitting process we discovered anomalies in certain pipeline segments on each of our expansion projects. Accordingly, we reduced the operating pressures on each pipeline below normal operating pressures as we proceed to perform additional testing procedures, remediate the anomalies and seek authority from PHMSA to increase operating pressures, first to normal operating pressures and subsequently to higher operating pressures under the special permit. We have also shut down pipeline segments for periods of time to remediate anomalies. We entered into an agreement with PHMSA during the second quarter 2009, which modified each of our special permits, that define the testing protocol and remediation efforts, including replacement of certain pipe joints, performing investigative digs to physically inspect the pipe sections and conducting metallurgical testing and analysis on a variety of pipe samples, that we need to complete in order to return to normal operating pressures and to operate at higher operating pressures. PHMSA retains discretion as to whether to grant, or to maintain in force, authority to operate a pipeline at higher operating pressures.

The pressure reductions and shutdowns that have been undertaken to remediate anomalies on our expansion pipeline projects have reduced throughput and adversely impacted our transportation revenues, net income and cash flow. With respect to each of our expansion pipelines, until we have remediated the pipe anomalies, performed additional testing required by PHMSA and obtained PHMSA's consent to increase operating pressures to normal levels, as well as higher levels under the special permits, we will not be able to operate that pipeline at its anticipated peak-day transmission capacity, which could continue to have a material adverse affect on our business, financial condition, results of operations and cash flow, including our ability to make distributions to unitholders. In addition, we have incurred and will continue to incur costs, which may be significant, to inspect, test and replace defective pipe segments on each of our expansion pipelines.

We are undertaking large, complex expansion projects which involve significant risks that may adversely affect our business.

We are currently undertaking several large, complex pipeline and storage expansion projects and we may also undertake additional expansion projects in the future. In pursuing these and previous projects, we have experienced significant cost overruns and we may experience cost increases in the future. We have also experienced delays in constructing and commissioning these pipelines and may experience additional delays in the future. Delays in construction and commissioning of new pipelines could result from a variety of factors and have resulted in penalties under customer contracts such as liquidated damage payments and could in the future result in similar losses. In some cases, certain customers could have the right to terminate their transportation agreements if the related expansion project is not completed by a date specified in their precedent agreements and the exercise of such rights could have a material adverse effect on our business, results of operations and cash flow, including our ability to make distributions to our unitholders.

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

- delays in obtaining regulatory approvals, including delays in receiving authorization from PHMSA to operate the expansion pipelines at higher operating pressures under special permits following the discovery of anomalies in portions of our expansion pipelines;

- difficult construction conditions, including adverse weather conditions, difficult river crossings and higher density rock formations than anticipated;

- delays in obtaining key materials; and

- shortages of qualified labor and escalating costs of labor and materials resulting from the high level of construction activity in the pipeline industry.

In pursuing current or future expansion projects, we could experience additional delays or cost increases for the reasons described above or as a result of other factors. We may not be able to complete our current or future expansion projects on the expected terms, cost or schedule, or at all. In addition, we cannot be certain that, if completed, we will be able to operate these projects, or that they will perform, in accordance with our expectations. Other areas of our business may suffer as a result of the diversion of our management's attention and other resources from our other business concerns to our expansion projects. Any of these factors could impair our ability to realize revenues from our expansion projects sufficient to cover the costs associated with owning and operating these pipelines and to provide the benefits we had anticipated from the projects, which could have a material adverse effect on our business, results of operations and cash flow, including our ability to make distributions to our unitholders.

Item 6. Exhibits

Exhibit Number	Description
*4.1	Subordination Agreement, dated as of May 1, 2009, among Boardwalk Pipelines Holding Corp., as Subordinated Creditor, Wachovia Bank, National Association, as Senior Creditor Representative, and Boardwalk Pipelines, LP, as Borrower.
*10.1	Subordinated Loan Agreement between Boardwalk Pipelines, LP as Borrower and Boardwalk Pipelines Holding Corp. as Lender dated May 1, 2009.
*10.2	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. Amendment No. 1 to Amended and Restated Revolving Credit Agreement, dated as of April 2, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, each a wholly-owned subsidiary of the Registrant, as Borrowers, and the agent and lender parties identified therein. Amendment No. 2 to Amended and Restated Revolving Credit Agreement, dated as of November 27, 2007, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein. Amendment No. 3 to Amended and Restated Revolving Credit Agreement, dated as of March 6, 2008, among the Registrant, Boardwalk Pipelines, LP, Texas Gas Transmission, LLC and Gulf South Pipeline Company, LP, and the agent and lender parties identified therein.
*31.1	Certification of Rolf A. Gafvert, Chief Executive Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*31.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Rule 13a-14(a) and Rule 15d-14(a).
*32.1	Certification of Rolf A. Gafvert, Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*32.2	Certification of Jamie L. Buskill, Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith

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SIGNATURES

Pursuant to the requirements 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: July 31, 2009	By:	/s/ Jamie L. Buskill Jamie L. Buskill Senior Vice President, Chief Financial Officer and Treasurer