PAA NATURAL GAS STORAGE LP
Form 10-Q
November 07, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

OR

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

Commission file number: 1-34722

PAA Natural Gas Storage, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**27-1679071** (I.R.S. Employer Identification No.)
333 Clay Street, Suite 1500, Houston, Texas (Address of principal executive offices)	**77002** (Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

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. x Yes o No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes o No

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 o	Accelerated filer x
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

As of October 31, 2012, there were 59,205,075 common units outstanding.

Table of Contents

PAA NATURAL GAS STORAGE, L.P. AND SUBSIDIARIES

TABLE OF CONTENTS

Table of Contents

PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Balance Sheets

(in thousands, except units)

	September 30, 2012 (unaudited)	December 31, 2011
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 448	$ 496
Accounts receivable	18,064	33,600
Natural gas inventory	50,829	50,942
Other current assets	5,645	8,917
Total current assets	74,986	93,955
PROPERTY AND EQUIPMENT		
Property and equipment	1,352,195	1,311,553
Less: Accumulated depreciation, depletion and amortization	(44,668)	(31,140)
Property and equipment, net	1,307,527	1,280,413
OTHER ASSETS		
Base gas	51,235	48,432
Goodwill	325,470	325,470
Intangibles and other assets, net	86,414	101,729
Total other assets, net	463,119	475,631
Total assets	$ 1,845,632	$ 1,849,999
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 24,864	$ 40,884
Short-term debt	80,138	67,992
Accrued taxes	2,471	1,296
Total current liabilities	107,473	110,172
LONG-TERM LIABILITIES		
Note payable to PAA	200,000	200,000
Long-term debt under credit agreements	295,262	253,508
Other long-term liabilities	1,306	693
Total long-term liabilities	496,568	454,201
Total liabilities	604,041	564,373
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS CAPITAL		
Common unitholders (59,205,075 units issued and outstanding at September 30, 2012)	1,016,360	1,037,161
Subordinated unitholders (25,434,351 units issued and outstanding at September 30, 2012)	225,780	230,359
General partner	28,609	28,156
Accumulated other comprehensive income/(loss)	(29,158)	(10,050)

Total partners capital		1,241,591		1,285,626
Total liabilities and partners capital	$	1,845,632	$	1,849,999

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

Table of Contents

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Statements of Operations

(in thousands, except per unit data)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
	(unaudited)		(unaudited)	
REVENUES:				
Firm storage services	$ 36,364	$ 35,536	$ 105,646	$ 100,075
Hub services	2,175	1,830	7,647	6,465
Natural gas sales	26,001	40,718	158,621	74,787
Other	1,587	1,250	3,076	2,791
Total revenues	66,127	79,334	274,990	184,118
COSTS AND EXPENSES:				
Storage-related costs	4,448	5,532	15,468	17,872
Natural gas sales costs	24,736	40,053	152,081	72,785
Field operating costs	2,974	3,070	9,030	9,072
General and administrative expenses	4,641	4,368	14,304	18,193
Depreciation, depletion and amortization	9,461	9,193	27,855	24,602
Total costs and expenses	46,260	62,216	218,738	142,524
OPERATING INCOME	19,867	17,118	56,252	41,594
OTHER INCOME/(EXPENSE):				
Interest expense (net of capitalized interest of $1,573, $2,724, $6,094 and $8,441, respectively)	(1,973)	(1,666)	(5,350)	(3,945)
Other income/(expense), net	(5)	(7)	12	10
NET INCOME	$ 17,889	$ 15,445	$ 50,914	$ 37,659
NET INCOME AVAILABLE TO LIMITED PARTNERS	$ 17,231	$ 14,919	$ 48,995	$ 36,526
NET INCOME PER LIMITED PARTNER UNIT				
Common and Series A subordinated units (1) (Basic)	$ 0.24	$ 0.21	$ 0.69	$ 0.54
Common and Series A subordinated units (1) (Diluted)	$ 0.24	$ 0.21	$ 0.69	$ 0.54
WEIGHTED AVERAGE LIMITED PARTNER UNITS OUTSTANDING				
Common and Series A subordinated units (1) (Basic)	71,136	71,125	71,131	67,279
Common and Series A subordinated units (1) (Diluted)	71,253	71,136	71,248	67,294

(1) Excludes Series B subordinated units. See Note 8, Net Income per Limited Partner Unit.

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

Table of Contents

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Statements of Comprehensive Income

(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(unaudited)		(unaudited)	
Net income	$ 17,889	$ 15,445	$ 50,914	$ 37,659
Other comprehensive income/(loss)	(4,064)	(3,573)	(19,108)	(3,317)
Comprehensive income	$ 13,825	$ 11,872	$ 31,806	$ 34,342

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income/(Loss)

(in thousands)

	Total (unaudited)
Balance, December 31, 2011	$ (10,050)
Reclassification adjustments	(16,904)
Deferred gain/(loss) on cash flow hedges, net	(2,204)
Total period activity	(19,108)
Balance, September 30, 2012	$ (29,158)

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

Table of Contents

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Statements of Cash Flows

(in thousands)

	Nine Months Ended September 30, 2012	2011
	(unaudited)	
Cash flows from operating activities		
Net income	$ 50,914	$ 37,659
Adjustments to reconcile to cash flow from operations		
Depreciation, depletion and amortization	27,855	24,602
Equity compensation expense	3,601	3,360
Unrealized (gain)/loss on derivative instruments	(72)	(235)
Changes in assets and liabilities, net of acquisitions	(13,385)	(2,359)
Net cash provided by operating activities	68,913	63,027
Cash flows from investing activities		
Additions to property and equipment	(43,444)	(57,662)
Cash paid in connection with acquisition, net of cash acquired		(744,209)
Decrease/(increase) in restricted cash		20,000
Cash received/(paid) related to base gas sales/(purchases), net	(280)	(5,292)
Other investing activities	1	
Net cash used in investing activities	(43,723)	(787,163)
Cash flows from financing activities		
Borrowings under credit agreements	241,900	437,800
Repayments of borrowings under credit agreements	(188,000)	(444,800)
Borrowings from parent		200,000
Net proceeds from issuance of common units		587,347
Costs incurred in connection with financing arrangements	(386)	(2,561)
Contributions from general partner	4	12,004
Distributions paid to unitholders	(76,285)	(64,086)
Distributions paid to general partner	(2,223)	(1,525)
Distribution equivalent right payments	(248)	(47)
Net cash provided by/(used in) financing activities	(25,238)	724,132
Net increase/(decrease) in cash and cash equivalents	(48)	(4)
Cash and cash equivalents, beginning of period	496	346
Cash and cash equivalents, end of period	$ 448	$ 342
Cash paid for interest, net of amounts capitalized	$ 5,169	$ 2,902
Non-cash investing and financing activities		
Increase/(decrease) in non-cash asset purchases included in accounts payable	$ (463)	$ 1,811

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

Table of Contents

PAA Natural Gas Storage, L.P. and Subsidiaries

Condensed Consolidated Statement of Changes in Partners Capital

(in thousands)

	Partners Capital Limited Partners Common	Subordinated Series A	Series B	General Partner	Accumulated Other Comprehensive Income/(Loss)	Total
			(unaudited)			
Balance at December 31, 2011	$ 1,037,161	$ 128,568	$ 101,791	$ 28,156	$ (10,050)	$ 1,285,626
Net income	41,022	8,221		1,671		50,914
Equity compensation expense	2,034			1,001		3,035
Distributions to unitholders and general partner	(63,485)	(12,800)		(2,223)		(78,508)
Distribution equivalent rights paid or accrued	(372)					(372)
Contributions from general partner				4		4
Change in deferred gain/(loss) on cash flow hedges, net					(19,108)	(19,108)
Balance at September 30, 2012	$ 1,016,360	$ 123,989	$ 101,791	$ 28,609	$ (29,158)	$ 1,241,591

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

PAA Natural Gas Storage, L.P. and Subsidiaries

Notes to the Condensed Consolidated Financial Statements

(unaudited)

Note 1 Organization and Basis of Presentation

PAA Natural Gas Storage, L.P. (the Partnership or PNG) is a Delaware limited partnership formed on January 15, 2010 to own the natural gas storage business of Plains All American Pipeline, L.P. (PAA). The Partnership is a fee-based, growth-oriented partnership engaged in the ownership, acquisition, development, operation and commercial management of natural gas storage facilities.

We currently own and operate three natural gas storage facilities located in Louisiana, Mississippi and Michigan. Our Pine Prairie and Southern Pines facilities are recently constructed, high-deliverability salt cavern natural gas storage complexes located in Evangeline Parish, Louisiana and Greene County, Mississippi, respectively. Our Bluewater facility is a depleted reservoir natural gas storage complex located approximately 50 miles from Detroit in St. Clair County, Michigan. As of September 30, 2012, through these facilities, PNG had a total of nine operational salt storage caverns and two depleted reservoirs used for natural gas storage, with an aggregate owned working gas storage capacity of approximately 93 billion cubic feet (Bcf). We also own PNG Marketing, LLC, a wholly owned commercial optimization company that captures short-term market opportunities by leasing a portion of our storage capacity and engaging in related commercial marketing activities.

As of September 30, 2012, PAA owned approximately 64% of the equity interests in the Partnership, including our 2.0% general partner interest and limited partner interests consisting of 28,155,526 common units, 11,934,351 Series A subordinated units and 13,500,000 Series B subordinated units.

The accompanying condensed consolidated interim financial statements include the accounts of PNG and its subsidiaries, all of which are wholly owned, and should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2011 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the SEC. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income attributable to the Partnership. The condensed balance sheet data as of December 31, 2011 was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP. The results of operations for the three and nine months ended September 30, 2012 should not be taken as indicative of the results to be expected for the full year.

As used in this document, the terms we, us, our and similar terms refer to the Partnership, unless the context indicates otherwise.

Property and Equipment

During the nine months ended September 30, 2011, we received cash of approximately $7.2 million under a state incentive program for jobs creation. This incentive payment, which was determined based on applicable capital expenditures, was accounted for as a refund of sales tax previously paid and reduced the carrying value of our applicable property and equipment.

Note 2 Recent Accounting Pronouncements

Other than as discussed below and in our 2011 Annual Report on Form 10-K, no new accounting pronouncements have become effective during the nine months ended September 30, 2012 that are of significance or potential significance to us.

In July 2012, the FASB issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance will be effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We will adopt this guidance on January 1, 2013. Our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

Table of Contents

In September 2011, the FASB issued guidance with the purpose of simplifying the goodwill impairment test by permitting entities to perform a qualitative assessment to determine whether further impairment testing is necessary. If qualitative factors indicate that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, an entity need not perform the two-step goodwill impairment test. This guidance became effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We adopted this guidance on January 1, 2012. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance regarding the presentation of other comprehensive income, which was later amended in December 2011, with the purpose of increasing the prominence of other comprehensive income in financial statements. This guidance, as amended, requires entities to present comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. This guidance became effective for interim and annual periods beginning after December 15, 2011. We adopted the guidance, as amended, on January 1, 2012. Since this guidance only impacts the presentation of comprehensive income and does not change the composition or calculation of such financial information, adoption did not have a material impact on our financial position, results of operations or cash flows.

In May 2011, the FASB issued guidance to amend certain fair value measurement and disclosure requirements in an effort to improve consistency with international reporting standards. The amendments generally clarify that the concepts of highest and best use and valuation premise in fair value measurement are relevant only when measuring the fair value of non-financial assets and are not relevant when measuring the fair value of financial assets or of liabilities. In addition, the guidance expanded disclosure requirements associated with (i) unobservable inputs for Level 3 fair value measurements and (ii) items that are not measured at fair value in the financial statements, but for which fair value is required to be disclosed. This guidance became effective prospectively for interim and annual reporting periods beginning after December 15, 2011. We adopted this guidance on January 1, 2012. Other than requiring additional disclosure, which is included in Note 7, our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3 Accounts Receivable

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At September 30, 2012 and December 31, 2011, substantially all of our accounts receivable were current and we had no allowance for doubtful accounts.

Our accounts receivable are from a broad mix of customers, including local gas distribution companies, electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers and affiliates of such entities.

To mitigate credit risks related to our accounts receivable, we have in place a rigorous credit review process. We closely monitor market conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, parental guarantees or advance cash payments. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables against each other) that cover substantially all of our natural gas purchases and sales transactions and also serve to mitigate credit risk.

Note 4 Acquisition

On February 9, 2011, we completed the acquisition of SG Resources Mississippi, L.L.C., owner of the Southern Pines Energy Center natural gas storage facility (the Southern Pines Acquisition). The purchase price was approximately $765 million (approximately $750 million net of cash and other working capital acquired).

Table of Contents

The purchase price allocation was as follows (in millions):

Description		Amount	Average Depreciable Life (in years)
Inventory	$	14	n/a
Property and equipment		340	5 70
Base gas		3	n/a
Other working capital (including approximately $13 million of cash acquired)		15	n/a
Intangible assets		92	2 10
Goodwill		301	n/a
Total	$	765	

In conjunction with the Southern Pines Acquisition, we arranged financing totaling approximately $800 million to fund the purchase price, closing costs and the first 18 months of expected expansion capital. The financing consisted of $200 million of borrowings under a promissory note from PAA (see Note 7) and approximately $600 million from the issuance of our common units (see Note 9).

During the nine months ended September 30, 2011, we incurred approximately $4.1 million of acquisition-related costs associated with the Southern Pines Acquisition. Such costs are reflected as a component of general and administrative expenses in our condensed consolidated statement of operations.

In May 2011, we entered into an agreement with the former owners of SG Resources Mississippi, LLC with respect to certain outstanding issues and purchase price adjustments as well as the distribution of the remaining purchase price that was escrowed at closing. Pursuant to this agreement, we received approximately $10 million and the balance was remitted to the former owners. Funds received by us have been and will continue to be used to fund anticipated facility development and other related costs identified subsequent to closing. None of these funds were spent during the nine months ended September 30, 2012.

Pro Forma Results

Selected unaudited pro forma results of operations for the nine months ended September 30, 2011, assuming the Southern Pines Acquisition had occurred on January 1, 2010, are presented below (in thousands, except per unit amounts):

		Nine Months Ended September 30, 2011
Total revenues	$	188,081
Net income (1)	$	42,963
Limited partner interest in net income (2)	$	41,723
Net income per limited partner unit (2)		
Basic	$	0.59

Diluted	$	0.59

(1) Amount for the period excludes approximately $4.1 million of acquisition costs associated with the Southern Pines Acquisition.

(2) Excludes Series B subordinated units. See Note 8, Net Income per Limited Partner Unit.

Table of Contents

Note 5 Inventory and Base Gas

Inventory and base gas consisted of the following (natural gas volumes in thousands and carrying values in thousands):

	September 30, 2012				December 31, 2011			
	Volumes	Unit of Measure		Carrying Value (1)	Volumes	Unit of Measure		Carrying Value (1)
Inventory								
Natural gas (2)(3)(4)	21,800	Mcf	$	50,829	16,170	Mcf	$	50,942
Base Gas								
Natural gas (5)	15,005	Mcf		51,235	14,105	Mcf		48,432
Total			$	102,064			$	99,374

(1) Carrying value represents a weighted-average associated with various locations; accordingly, these values may not coincide with any published benchmarks for such products.

(2) Includes fuel inventory held for operational purposes.

(3) As of December 31, 2011, the carrying value of natural gas inventory reflects lower of cost or market adjustments of approximately $6.0 million. No lower of cost or market adjustments were included in the carrying value of natural gas inventory as of September 30, 2012. Lower of cost or market adjustments are reflected as a component of natural gas sales costs in our accompanying condensed consolidated statement of operations. The impacts of such adjustments are generally offset by the recognition of unrealized gains on derivative instruments (see Note 11) being utilized to hedge the future sales of our natural gas inventory.

(4) Natural gas inventory balances exclude derivative gains and losses associated with settled derivatives which were entered into to hedge natural gas inventory purchases. As of September 30, 2012, net deferred losses of approximately $27.8 million associated with settled derivatives are reflected as a component of accumulated other comprehensive income/(loss) in our condensed consolidated balance sheet. Such amounts will be reclassified to earnings in conjunction with an earnings impact associated with the applicable purchase inventory (typically when such inventory is sold).

(5) During the quarter ended September 30, 2012, we purchased approximately 0.9 Bcf of base gas for approximately $5.7 million (including approximately $3.2 million related to derivative settlements). Approximately $1.1 million of the purchase price is included as a component of accounts payable and accrued liabilities in our accompanying condensed consolidated balance sheet as of September 30, 2012. Also, during the nine months ended September 30, 2012, we received approximately $4.3 million of cash for base gas sold during 2011.

Note 6 Goodwill

The table below reflects our changes in goodwill for the period indicated (in thousands):

		Total
Balance, December 31, 2011	$	325,470

2012 Goodwill Related Activity:		
Acquisitions		
Purchase price accounting adjustments and other		
Balance, September 30, 2012	$	325,470

Note 7 Debt

On June 1, 2012, the Partnership and PAA entered into an amendment (the PAA Promissory Note Amendment) to the PAA Promissory Note, which was originally entered into during 2011. The PAA Promissory Note Amendment modified the terms of the PAA Promissory Note by (i) reducing the interest rate from 5.25% per annum to 4.00% per annum and (ii) extending the scheduled maturity date from February 9, 2014 to June 1, 2015. The remaining terms of the PAA Promissory Note were unchanged.

On June 27, 2012 we partially exercised the accordion feature of our revolving credit facility, increasing borrowing capacity from $250 million to $350 million. Also on June 27, 2012, we reached an agreement with applicable lenders to amend certain terms and provisions of our senior unsecured credit agreement (the Credit Agreement Amendment). Pursuant to the Credit Agreement Amendment, the revolving credit facility commitments may be further increased to $550 million, subject to, among other terms and conditions, obtaining additional or increased lender commitments. The Credit Agreement Amendment also provides for one or more one-year extensions of the maturity date of the revolving credit facility and the date (the GO Bond Mandatory Put Date) on which the Purchasers of the GO Bond Term Loans have the right to require the Partnership to repurchase such loans, in each case, subject to

Table of Contents

applicable lender approval and other terms and conditions set forth in the credit agreement, as amended. The revolving credit facility will expire and all amounts outstanding under it will mature on August 19, 2016 unless, such maturity date is extended pursuant to the terms of the credit agreement, as amended, and the purchasers of the two GO Bond Term Loans have the right to put, at par, to the Partnership the GO Bond Term Loans on August 19, 2016 unless such GO Bond Mandatory Put Date is extended pursuant to the terms of the credit agreement, as amended. The maturity dates for the GO Bonds, which mature by their terms on May 1, 2032 and August 1, 2035, respectively, were not changed by the Credit Agreement Amendment. Provisions of the credit agreement providing for the calculation and payment of interest or fees and regarding covenants, including the financial covenants, events of default and lender remedies were substantially unchanged by the Credit Agreement Amendment, as were the terms providing for the issuance of letters of credit.

Debt consisted of the following (in thousands):

	September 30, 2012	December 31, 2011
Short-Term Debt		
Senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.4% at both September 30, 2012 and December 31, 2011(1) (2)	$ 80,138	$ 67,992
Total short-term debt	80,138	67,992
Long-Term Debt		
Senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.4% at both September 30, 2012 and December 31, 2011(1) (2)	95,262	53,508
GO Bond Term Loans, bearing a weighted-average interest rate of 1.5% at both September 30, 2012 and December 31, 2011 (2)	200,000	200,000
Promissory note due to PAA bearing interest of 4.0% and 5.25% at September 30, 2012 and December 31, 2011, respectively (2)	200,000	200,000
Total long-term debt	495,262	453,508
Total debt (1) (2)	$ 575,400	$ 521,500

(1) We classify as short-term debt any borrowings under our senior unsecured revolving credit facility that have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of our funded hedged natural gas inventory or NYMEX margin requirements. Approximately $0.4 million and $0.9 million of interest expense attributable to such borrowings is reflected as a component of natural gas sales costs in the accompanying condensed consolidated statements of operations for the three and nine months ended September 30, 2012, respectively.

(2) We estimate that the fair value of borrowings outstanding under our credit agreement (including the revolving credit facility and GO Bond Term Loans) and the PAA Promissory Note approximate carrying value due to the short maturity of both obligations and the variable interest rate terms set forth under our credit agreement. Our fair value estimate for amounts outstanding under our credit agreement is based upon observable market data and is classified with Level 2 of the fair value hierarchy. With regard to the PAA Promissory Note, our fair valuation estimation process incorporates our estimated credit spread, an unobservable input. As such, we consider this to be a Level 3 measurement within the fair value hierarchy.

Our revolving credit facility includes the ability to issue letters of credit. As of September 30, 2012, we had $1.8 million of outstanding letters of credit under our revolving credit facility.

As of September 30, 2012, we were in compliance with the covenants required by our credit agreement.

Interest payments on the PAA Promissory Note are paid semiannually on the last business day of June and December. Interest paid to PAA during the nine months ended September 30, 2012 was approximately $5.0 million. Accrued interest payable due under the PAA Promissory Note (which is reflected as a component of accounts payable and accrued liabilities on our accompanying condensed consolidated balance sheet) was approximately $2.0 million as of September 30, 2012. There was no accrued interest payable due under the PAA Promissory Note as of December 31, 2011.

Capitalized interest for the three and nine months ended September 30, 2012 was $1.6 million and $6.1 million, respectively, and $2.7 million and $8.4 million for the three and nine months ended September 30, 2011, respectively.

Table of Contents

Note 8 Net Income per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined pursuant to the two-class method for Master Limited Partnerships as prescribed in the FASB guidance. The two-class method is an earnings allocation formula that is used to determine earnings to our general partner, limited partner unit holders and participating securities according to distributions pertaining to the current period s net income and participation rights in undistributed earnings. Under this method, all earnings are allocated to our general partner, limited partner unit holders and participating securities based on their respective rights to receive distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

The Partnership calculates basic and diluted net income per limited partner unit by dividing net income, after deducting the amount allocated to the general partner s interest, incentive distribution rights (IDRs) and participating securities, by the basic and diluted weighted-average number of limited partner units outstanding during the period. Participating securities include LTIP awards that have vested distribution equivalent rights (DERs), which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income per limited partner unit is computed based on the weighted-average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

Table of Contents

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2012 and 2011 (amounts in thousands, except per unit data):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Net income	$ 17,889	$ 15,445	$ 50,914	$ 37,659
Less: General partner s incentive distribution	222	222	666	388
Less: General partner s 2% ownership interest	353	304	1,005	745
Less: Amounts attributable to participating securities (1)	83		248	
Net income available to limited partners	$ 17,231	$ 14,919	$ 48,995	$ 36,526
Numerator for basic and diluted earnings per limited partner unit:				
Allocation of net income amongst limited partner interests:				
Net income allocable to common units	$ 14,340	$ 12,416	$ 40,775	$ 30,047
Net income allocable to Series A subordinated units	2,891	2,503	8,220	6,479
Net income allocable to Series B subordinated units (2)				
Net income available to limited partners	$ 17,231	$ 14,919	$ 48,995	$ 36,526
Denominator:				
Basic weighted average number of limited partner units outstanding: (2)(3)(4)				
Common units	59,202	59,191	59,197	55,345
Series A subordinated units	11,934	11,934	11,934	11,934
Series B subordinated units	13,500	13,500	13,500	13,500
Diluted weighted average number of limited partner units outstanding: (2)(3)(4)				
Common units	59,319	59,202	59,314	55,360
Series A subordinated units	11,934	11,934	11,934	11,934
Series B subordinated units	13,500	13,500	13,500	13,500
Basic and diluted net income per limited partner unit: (2)(3)(4)				
Common units	$ 0.24	$ 0.21	$ 0.69	$ 0.54
Series A subordinated units	$ 0.24	$ 0.21	$ 0.69	$ 0.54
Series B subordinated units	$	$	$	$

(1) Participating securities consist of LTIP awards (see Note 10) containing vested distribution equivalent rights which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

(2) For each of the periods presented, our Series B subordinated units were not entitled to participate in our earnings, losses or distributions in accordance with the terms of our partnership agreement as necessary performance conditions have not been satisfied. As a result, no earnings were allocated to the Series B subordinated units in our determination of basic and diluted net income per limited partner unit.

(3) The determination of diluted weighted average units outstanding excludes the impact of equity-classified LTIP awards (see Note 10) which contain provisions whereby vesting occurs only upon the satisfaction of a performance condition, none of which had been satisfied during

any of the periods presented.

(4) The conversion of (i) our Series A subordinated units to common units and (ii) our Series B subordinated units to Series A subordinated units or common units is subject to certain performance conditions. None of these performance conditions had been satisfied as of September 30, 2012 therefore, there is no dilutive impact of such units in our determination of diluted net income per limited partner unit.

Table of Contents

Note 9 Partners Capital and Distributions

Modification of Terms of Series B Subordinated Units

In February 2012, we modified the terms of our Series B subordinated units, which modification was approved by PAA, the owner of all of the Series B subordinated units. The Partnership s Series B subordinated units do not participate in quarterly distributions. Instead, the Series B subordinated units convert into Series A subordinated units or common units in five distinct tranches upon the achievement of defined benchmarks tied to the amount of capacity in service at Pine Prairie and increases in our quarterly distributions. The modification increases the quarterly distribution benchmark for the first three of the five tranches, totaling 7.5 million Series B subordinated units in the aggregate, to an annualized level of $1.71 per unit. Previously, the quarterly distribution levels required to cause conversion for these three tranches were at annualized levels of $1.44, $1.53 and $1.63 per unit. The modification, which was made in recognition of the continued challenging market conditions facing the natural gas storage business, benefits our common unitholders by reducing the number of units on which distributions would otherwise be required to be paid in the case of distributions below the annualized level of $1.71. The following table presents the operational and financial benchmarks, as modified, for conversion of the Series B subordinated units into Series A subordinated units for each tranche (units in millions):

	Series B Subordinated Units to Convert into Series A Subordinated Units	Working Gas Storage Capacity (Bcf)	Annualized Distribution Level (1)
Tranche 1	2.6	29.6	$ 1.71
Tranche 2	2.8	35.6	$ 1.71
Tranche 3	2.1	41.6	$ 1.71
Tranche 4	3	48	$ 1.71
Tranche 5	3	48	$ 1.80

(1) For satisfaction of this benchmark, PNG must, for two consecutive quarters, (i) generate distributable cash flow sufficient to pay a quarterly distribution of at least the annualized distribution benchmark on the weighted-average number of common units and Series A subordinated units outstanding during such quarter plus all of such Series B subordinated units and (ii) distribute available cash of at least the annualized distribution benchmark on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2% interest and the related distributions on the incentive distribution rights. See Note 6 to our consolidated financial statements included in Part IV of our 2011 Annual Report on Form 10-K for a complete discussion of our Series B subordinated units.

Outstanding Units

From December 31, 2011 through September 30, 2012, changes in our issued and outstanding common, Series A subordinated or Series B subordinated units were as follows:

		Subordinated		
	Common	Series A	Series B	Total
Balance, December 31, 2011	59,193,825	11,934,351	13,500,000	84,628,176

Vesting of LTIP awards	11,250			11,250
Balance, September 30, 2012	59,205,075	11,934,351	13,500,000	84,639,426

Table of Contents

Distributions

The following table details the distributions on our common and Series A subordinated units declared for 2012 quarterly periods or paid during the nine months ended September 30, 2012 (in millions, except per unit amounts):

		Distributions Paid					
			Series A				
		Common	Subordinated	General Partner			Distribution
Date Declared	Date Paid or To Be Paid	Units	Units	Incentive	2%	Total	per unit
October 4, 2012	November 14, 2012 (1)	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
July 10, 2012	August 14, 2012	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
April 10, 2012	May 15, 2012	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575
January 12, 2012	February 14, 2012	$ 21.2	$ 4.3	$ 0.2	$ 0.5	$ 26.2	$ 0.3575

(1) Payable to unitholders of record on November 2, 2012, for the period July 1, 2012 through September 30, 2012.

Equity Offerings

On February 8, 2011, in connection with the Southern Pines Acquisition, we completed the sale in a private placement of approximately 17.4 million common units to third-party purchasers and approximately 10.2 million common units to PAA for total proceeds of approximately $600 million, including PAA s proportionate general partner contribution.

Note 10 Equity Compensation Plans

Long Term Incentive Plan (LTIP)

For discussion of our equity compensation awards, see Note 12 to our consolidated financial statements included in Part IV of our 2011 Annual Report on Form 10-K.

In February 2012, the Board of Directors of our general partner approved the modification of certain equity compensation awards previously granted under the 2010 LTIP Plan. As a result of the modification, 232,500 equity-classified phantom unit awards will now vest in the following manner: (i) 69,750 awards, with distribution equivalent rights also modified to begin payment in February 2012, will vest upon the date we pay an annualized distribution of at least $1.45, (ii) 69,750 awards, with distribution equivalent rights also modified to begin payment in May 2013, will vest upon the date we pay an annualized distribution of at least $1.50 and (iii) 93,000 awards, with distribution equivalent rights also modified to begin payment in May 2014, will vest upon the date we pay an annualized distribution of at least $1.55. Fifty percent of any awards that have not vested as of the November 2016 distribution date will vest at that time and the remainder will expire. Additionally, 232,500 of equity-classified phantom unit awards with vesting terms originally tied to the conversion of our Series A and Series B subordinated units were modified such that all these awards will now fully vest upon conversion of the Series A subordinated units to common units. Distribution equivalent rights were also granted with respect to these awards beginning February 2012.

Our equity compensation activity for awards denominated in PNG units is summarized in the following table (units in thousands):

	Units (1)		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2011	499	$	19.53
Granted	131	$	15.33
Vested	(11)	$	23.46
Cancelled or forfeited			
Outstanding, September 30, 2012 (2)	619	$	15.75

Table of Contents

(1) Amounts do not include Class B units of PNGS GP LLC or transaction awards granted by PAA.

(2) Weighted-average grant date fair value per unit for PNG units outstanding at September 30, 2012, reflects the impact of the modification of PNG awards during February 2012, as discussed above.

The table below summarizes the expense recognized and unit or cash settled vestings related to equity compensation awards during the three and nine months ended September 30, 2012 and 2011 (in thousands):

	Three Months Ended September 30, 2012		Nine Months Ended September 30, 2012	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity compensation expense(1)	$ 278	$ 952	$ 566	$ 3,035
LTIP cash settled vestings (2)	$	$	$ 740	$
Distribution equivalent right payments	$ 7	$ 83	$ 19	$ 248
LTIP unit settled vestings (3)		11		11

	Three Months Ended September 30, 2011		Nine Months Ended September 30, 2011	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity compensation expense(1)	$ 41	$ 661	$ 327	$ 3,033
LTIP cash settled vestings (2)	$	$	$ 580	$
Distribution equivalent right payments	$ 4	$ 15	$ 11	$ 46
LTIP unit settled vestings (3)		9		9

(1) Includes expense associated with transaction awards granted by PAA and denominated in PNG units owned by PAA. These awards, which were granted in September 2010, are not included in units outstanding above. The entire economic burden of these agreements will be borne solely by PAA and will not impact our cash or units outstanding. The individuals that received these awards are officers of PAA and PNG, and because they also serve as officers of PNG and PNG benefits as a result of the services they provide, we recognize the grant date fair value of these awards as compensation expense over the service period, with such expense recognized as a capital contribution. We recognized approximately $0.2 million and $1.0 million of compensation expense associated with these equity-classified awards during the three and nine months ended September 30, 2012, respectively. We recognized approximately $0.5 million and $2.4 million of compensation expense associated with these equity-classified awards during the three and nine months ended September 30, 2011, respectively.

(2) Includes cash payments made in conjunction with the settlement of PAA common unit denominated LTIP awards.

(3) Amounts represent number of units vested.

Note 11 Derivatives and Risk Management Activities

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our risk management strategies utilize various derivatives to manage our exposure to both commodity price risk and interest rate risk. When we apply hedge accounting, at the inception of a hedge we formally document the relationship between the hedging instrument and the hedged item, as well as our risk management objective for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives within the hedging relationship are highly effective in offsetting changes in cash flows of hedged items. Our policy is to use derivatives only for hedging purposes and not for the purpose of speculating.

Commodity Price Risk Hedging

We utilize derivatives to manage exposure associated with commodity price risk (resulting from natural gas price fluctuations in spot and forward markets, among other factors) and to optimize profits as follows:

Table of Contents

Merchant Storage Activities- When contango market conditions exist (forward prices exceed spot prices), our commercial optimization company may utilize our storage capacity to purchase natural gas and hold it for sale at a higher price in a forward month. Additionally, our commercial optimization company may sell owned natural gas inventory in the current month and repurchase it at a lower price in a forward month when favorable market conditions exist.

Operational Gas Purchases and Sales- We purchase and sell natural gas for operational purposes at our storage facilities. These activities primarily consist of the purchase of base gas for caverns under development or anticipated future development of our facilities. We also sell surplus fuel inventory, which we collect from our customers under the terms of our storage contracts.

Crude Oil Sales- We sell crude oil and liquids produced in conjunction with the operation of our Bluewater facility.

Storage Capacity Utilization- The fair value of our storage capacity is partially derived from the seasonal spread in forward natural gas prices. We may from time to time use derivatives to hedge our exposure associated with available capacity.

The risk management strategies we utilize to manage commodity price risk exposure associated with these core activities include the use of exchange-cleared futures, swaps (including basis and index swaps) and options.

In conjunction with our merchant storage activities, we typically enter into a spread position to hedge both purchases and sales of natural gas in the respective months. The hedging instrument for each respective month is settled concurrent with the applicable physical transaction. This enables us to maintain a balanced position when our hedging instruments are aggregated with physical purchases and sales. The fair value of our derivative spread positions is exposed to changes in the spread (the difference in commodity price between two distinct months). However, the fair value of our derivative spread positions is not exposed to changes in outright prices and is offset by the corresponding change in fair value of the physical position that is being hedged.

The following table summarizes open derivative positions utilized in commodity price risk management strategies as of September 30, 2012:

	Notional Volume (Short)/Long	**Remaining Tenor (1)**
Anticipated natural gas purchases (2)(3)	7.5 Bcf	April 2016
Anticipated natural gas sales of owned inventory (2)	(24.3) Bcf	January 2013
Anticipated sales of crude oil	(6,000) bbls	December 2012
Storage capacity utilization purchased call options (4)	3 Bcf	January 2013

(1) Volumes presented represent net position through the month noted.

(2) Excludes spread positions through November 2014, which consist of an offsetting purchase and sale between two different months, of 47.4 Bcf.

(3) Includes 5.0 Bcf of anticipated base gas purchases through April 2016.

(4) These options do not qualify for hedge accounting. Risk associated with these options is limited to aggregate premiums paid of approximately $0.3 million.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge the underlying benchmark interest rate associated with borrowings outstanding under our debt facilities. During June 2011 and August 2011, we entered into three interest rate swaps to fix the interest rate on a portion of our outstanding debt. The swaps have an aggregate notional amount of $100 million with an average fixed rate of 0.95%. Two of these swaps terminate in June 2014 and the remaining swap terminates in August 2014. These swaps are designated as cash flow hedges.

Summary of Financial Statement Impact

For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. Derivatives that do not qualify or were not designated for hedge accounting, and the portion of cash flow hedges that are not highly effective in offsetting change in cash flows of the hedged items, are recognized in earnings each period.

Table of Contents

A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2012 is as follows (in thousands):

	Three Months Ended September 30, 2012			Nine Months Ended September 30, 2012		
Location of gain/(loss)	**Derivatives in Hedging Relationships(1)(2)**	**Derivatives not Designated as a Hedge(3)**	**Total**	**Derivatives in Hedging Relationships(1)(2)**	**Derivatives not Designated as a Hedge(3)**	**Total**
Commodity Derivatives:						
Natural gas sales	$ (264)	$ (77)	$ (341)	$ 13,481	$ 86	$ 13,567
Natural gas sales costs(4)				3,877		3,877
Other revenues	409	283	692	310	(344)	(34)
Interest Rate Derivatives:						
Interest expense	(126)		(126)	(347)		(347)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 19	$ 206	$ 225	$ 17,321	$ (258)	$ 17,063

A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2011 is as follows (in thousands):

	Three Months Ended September 30, 2011			Nine Months Ended September 30, 2011		
Location of gain/(loss)	**Derivatives in Hedging Relationships(1)(2)**	**Derivatives not Designated as a Hedge(3)**	**Total**	**Derivatives in Hedging Relationships(1)(2)**	**Derivatives not Designated as a Hedge(3)**	**Total**
Commodity Derivatives:						
Natural gas sales	$ 60	$ (50)	$ 10	$ 1,713	$ 45	$ 1,758
Natural gas sales costs(4)	2,615		2,615	2,615		2,615
Other revenues	211	(11)	200	243	61	304
Interest Rate Derivatives:						
Interest expense	(147)		(147)	(175)		(175)
Total Gain/(Loss) on Derivatives Recognized in Net Income	$ 2,739	$ (61)	$ 2,678	$ 4,396	$ 106	$ 4,502

(1) Amounts reported as a component of natural gas sales in our accompanying condensed consolidated statements of operations represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.

(2) Amounts reported as a component of other revenues include the ineffective portion of our cash flow hedges recognized in earnings.

(3) Amounts include realized and unrealized gains or losses for derivatives that did not qualify or were not designated for hedge accounting during the period.

(4) Amounts reported as a component of natural gas sales costs in our accompanying condensed consolidated statements of operations reflect reclassifications from AOCI to earnings to offset applicable lower of cost or market adjustments to the carrying value of our inventory.

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of September 30, 2012 (in thousands):

Table of Contents

	As of September 30, 2012			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 22,869	Other current assets	$ (13,535)
	Other long-term assets	2,289	Other long-term assets	(1,501)
Interest rate derivatives			Other current liabilities	(554)
			Other long-term liabilities	(462)
Total derivatives designated as hedging instruments		$ 25,158		$ (16,052)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 522	Other current assets	$ (5)
Total derivatives not designated as hedging instruments		$ 522		$ (5)
Total derivatives		$ 25,680		$ (16,057)

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of December 31, 2011 (in thousands):

	As of December 31, 2011			
	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 31,541	Other current assets	$ (16,766)
	Other long-term assets	3,292	Other long-term assets	(1,896)
Interest rate derivatives			Other current liabilities	(236)
			Other long-term liabilities	(212)
Total derivatives designated as hedging instruments		$ 34,833		$ (19,110)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 138	Other current assets	$ (515)
	Other long-term assets	5		
Total derivatives not designated as hedging instruments		$ 143		$ (515)
Total derivatives		$ 34,976		$ (19,625)

Accumulated Other Comprehensive Income

As of September 30, 2012, there was a net loss of $29.2 million deferred in AOCI. Amounts deferred in AOCI include amounts associated with settled derivatives for which the underlying anticipated hedge transactions are still probable of occurring. The deferred loss in AOCI is expected to be reclassified to future earnings contemporaneously with the earnings recognition of the underlying hedged transactions. Certain underlying hedged transactions are for base gas purchases or other capital expansion expenditures. As we account for base gas as a long-term asset, which is not subject to depreciation, amounts related to base gas will not be reclassified to future earnings until such gas is sold or in the event an impairment charge is recognized in the future. Amounts related to other capital expansion activities will be reclassified to future earnings over the estimated useful life of the applicable asset. Deferred losses associated with capital expansion activities of approximately $11.5 million (including $9.1 million associated with base gas and anticipated base gas purchases) are included in AOCI as of September 30, 2012. Of the total net loss deferred in AOCI at September 30, 2012, we expect to reclassify a net loss of approximately $18.5 million to earnings in the next twelve months. The remaining net loss will be reclassified to earnings through 2014. Amounts deferred are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the nine months ended September 30, 2012, we reclassified gains of approximately $0.5 million, from AOCI to natural gas sales revenues as a result of anticipated hedged transactions no longer being considered probable of occurring. No gains or losses were reclassified to earnings as a result of anticipated hedge transactions no longer probable of occurring during the three months ended September 30, 2012. During the three and nine months ended September 30, 2011, we reclassified gains of approximately $0.7

Table of Contents

million from AOCI to natural gas sales revenues as a result of anticipated hedged transactions no longer being considered probable of occurring.

Amounts recognized in AOCI for derivatives and amounts reclassified to earnings during the three and nine months ended September 30, 2012 and 2011 are as follows (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Commodity derivatives, net (1)	$ (4,037)	$ 48	$ (1,289)	$ 1,926
Interest rate derivatives, net (1)	(353)	(882)	(915)	(851)
Reclassification adjustments, net (2)	326	(2,739)	(16,904)	(4,392)
Total	$ (4,064)	$ (3,573)	$ (19,108)	$ (3,317)

(1) Amounts reflect net derivative gains and losses deferred in AOCI for the period. Negative amounts represent a net deferral of losses and positive amounts reflect a net deferral of gains on the applicable activity.

(2) Reclassification adjustments represent transfers of deferred gains and losses out of AOCI and into earnings for the period. Negative amounts represent the reclassification of previously deferred net gains into earnings and positive amounts represent the reclassification of previously deferred net losses into earnings for the period. Reclassification adjustments may include realization of amounts originally deferred to AOCI in both the current period as well as prior periods.

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our commodity derivatives, which are all exchange-cleared, are transacted through a brokerage account and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or receipt of variation margin. As of September 30, 2012, we had a net broker payable of approximately $6.3 million (consisting of initial margin of $4.4 million decreased by $10.7 million of variation margin paid to us). Our interest rate derivatives, which are over-the-counter instruments, do not have margin requirements. At September 30, 2012 and 2011, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit standing.

Recurring Fair Value Measurements

Set forth in the table below are the Level 1 to Level 3 fair value hierarchy of our financial assets and liabilities that are accounted for at fair value on a recurring basis as of September 30, 2012 and December 31, 2011, respectively. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels.

Fair Value as of September 30, 2012	Fair Value as of December 31, 2011

	(in thousands)				(in thousands)			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 10,639	$	$	$ 10,639	$ 15,799	$	$	$ 15,799
Interest rate derivatives		(1,016)		(1,016)		(448)		(448)
Total	$ 10,639	$ (1,016)	$	$ 9,623	$ 15,799	$ (448)	$	$ 15,351

(1) Derivative assets and (liabilities) are presented above on a net basis but do not include any related cash margin deposits.

The fair value of our commodity derivatives and interest-rate derivatives include adjustments for credit risk. These fair value adjustments include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of our nonperformance risk on our liabilities. There were no changes to any of our valuation techniques during the period.

Table of Contents

Note 12 Commitments and Contingencies

Litigation

In the ordinary course of business, we are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental

We may experience releases of natural gas, brine, crude oil or other contaminants into the environment, or discover past releases that were previously undetected. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such releases from our assets may substantially affect our business. As of September 30, 2012, we have not identified any such material obligations.

Insurance

A natural gas storage facility, associated pipeline header system and gas handling and compression facilities may suffer damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to or destruction of property, base gas, or equipment, pollution or environmental damage, or suspension of operations. We maintain various types of insurance under PAA s insurance program that we consider adequate to cover our operations and properties. Such insurance covers our assets in amounts management considers reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating natural gas storage facilities, associated pipeline header systems, and gas handling and compression facilities, including the potential loss of significant revenues.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage with respect to our operations. In the future, we may not be able to maintain insurance at levels that we consider adequate for rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. For example, the market for hurricane-or windstorm-related property damage coverage has remained difficult the last few years. The amount of coverage available has been limited, and costs have increased substantially with the combination of premiums and deductibles.

In 2011, we elected not to renew our hurricane insurance and, instead, self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have renewed at our historic coverage levels. In addition, although we believe that we have established adequate reserves to the extent such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

During the three months ended September 30, 2011, we received $3.0 million of property insurance proceeds related to the January 2011 operational incident and fire at our Bluewater facility.

Property Tax Matter

During the third quarter of 2012, we received notice from the Industrial Development Board No. 1 of Evangeline Parish, Louisiana (IDB) (i) informing us of the fact that the IDB had received ad valorem property tax assessments for the years 2009 and 2011 with respect to property that is leased to Pine Prairie and (ii) alleging that Pine Prairie is responsible for any such taxes pursuant to the terms of the 2006 lease agreement between the IDB and Pine Prairie (Lease Agreement). Pine Prairie has denied responsibility for any such ad valorem taxes on the basis that the property owned by the IDB is exempt from ad valorem property taxation pursuant to applicable Louisiana law and the terms of the Lease Agreement. We have not recognized any property tax expense related to this matter and we are taking appropriate steps to enforce our rights under the Lease Agreement. This matter did not have a material impact on our results of operations for the period.

Table of Contents

Note 13 Operating Segments

We manage our operations through three operating segments, Pine Prairie, Southern Pines and Bluewater. We have aggregated these operating segments into one reporting segment, Gas Storage. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including adjusted EBITDA, volumes, adjusted EBITDA per thousand cubic feet (Mcf) and maintenance capital expenditures. We have aggregated our three operating segments into one reportable segment based on the similarity of their economic and other characteristics, including the nature of services provided, methods of execution and delivery of services, types of customers served and regulatory requirements. We define adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, unrealized gains and losses from derivative activities and other adjustments for the impact of unique and infrequent items, items outside of management s control and/or items that are not indicative of our core operating results and business outlook, which we refer to as selected items impacting comparability or selected items. The measure above excludes depreciation, depletion and amortization as we believe that depreciation, depletion and amortization are largely offset by repair and maintenance capital investments. Maintenance capital consists of expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating capability, service capability, and/or functionality of our existing assets.

The following table reflects certain financial data for our reporting segment for the periods indicated (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues	$ 66,127	$ 79,334	$ 274,990	$ 184,118
Adjusted EBITDA	$ 29,711	$ 26,858	$ 87,195	$ 73,865
Maintenance capital expenditures	$ 84	$ 51	$ 457	$ 266

The following table reconciles Adjusted EBITDA to consolidated net income (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Adjusted EBITDA	$ 29,711	$ 26,858	$ 87,195	$ 73,865
Selected items impacting Adjusted EBITDA:				
Equity compensation expense	(1,016)	(681)	(3,148)	(3,339)
Mark-to-market of open derivative positions	628	132	72	235
Acquisition-related expense		(5)		(4,055)
Insurance deductible related to property damage				(500)
Depreciation, depletion and amortization	(9,461)	(9,193)	(27,855)	(24,602)
Interest expense, net of capitalized interest	(1,973)	(1,666)	(5,350)	(3,945)
Net Income	$ 17,889	$ 15,445	$ 50,914	$ 37,659

Note 14 Related Party Transactions

In addition to transactions between PNG and PAA discussed in Notes 4, 7, 9, 10 and 12, additional activities between PNG and PAA are discussed below.

Total costs reimbursed by us to PAA for the three and nine months ended September 30, 2012, were approximately $4.4 million and $13.2 million, respectively; and approximately $4.8 million and $12.9 million for the three and nine months ended September 30, 2011, respectively. Of these amounts approximately $0.9 million and $2.7 million and $0.9 million and $2.7 million, during the three and nine month periods ended September 30, 2012 and 2011, respectively, were allocated costs for shared services (including personnel costs) and the remainder consisted of reimbursements for direct operating and capital costs that PAA paid on our behalf along with our allocation of insurance premiums for participation in PAA s insurance program.

As of September 30, 2012 and December 31, 2011, PNG had amounts due to PAA of approximately $2.6 million and $0.6 million, respectively, included in accounts payable and accrued liabilities on our accompanying condensed consolidated balance sheet. Such amounts include accrued interest, if any, due under the PAA Promissory Note (see Note 7).

Table of Contents

As of September 30, 2012 and December 31, 2011, PNG s obligation for unvested equity-based compensation awards for which we are required to reimburse PAA upon vesting and settlement was approximately $1.6 million and $1.2 million, respectively. Approximately $0.8 and $0.7 million of such amounts were reflected in accounts payable and accrued liabilities in our accompanying condensed consolidated balance sheets as of September 30, 2012 and December 31, 2011, respectively, with the remaining balances included as a component of other long-term liabilities at each respective date.

As of September 30, 2012, outstanding parental guarantees issued by PAA to third parties on behalf of PNG Marketing were approximately $15 million. No amounts were due to PAA as of September 30, 2012 under such guarantees and no payments were made to PAA under such guarantees during the nine months ended September 30, 2012. We pay PAA a quarterly fee in exchange for providing such parental guarantees. The quarterly fee, which is based on actual usage, is subject to a quarterly minimum of $12,500 regardless of utilization to cover PAA s administrative costs. During the three and nine months ended September 30, 2012, we incurred approximately $12,500 and $59,000, respectively, of expense under our obligation to reimburse PAA for administrative costs incurred in conjunction with providing parental guarantees on our behalf.

Natural Gas Services Agreement

Access fee revenues under our Natural Gas Services Agreement with Plains Gas Solutions, LLC. were approximately $0.4 million and $1.1 million, respectively, for the three and nine months ended September 30, 2012 and approximately $0.4 million for both the three and nine months ended September 30, 2011.

Natural Gas Sales

Revenues from sales of natural gas to Plains Gas Solutions, LLC. were approximately $0.2 million for the nine months ended September 30, 2012, and approximately $0.8 million for both the three and nine months ended September 30, 2011.

Relationship with our general partner

Except as previously disclosed, we are not party to any material transactions with our general partner or any of its affiliates. Additionally, our general partner is not obligated to provide any direct or indirect financial assistance to us or to increase or maintain its capital investment in us.

Table of Contents

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2011 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the condensed consolidated financial statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

Overview of Operating Results, Capital Spending and Significant Activities

Adjusted EBITDA for the nine months ended September 30, 2012 was approximately $87.2 million, an 18% increase over Adjusted EBITDA of approximately $73.9 million for the nine months ended September 30, 2011. This increase was primarily the result of the completion of the Southern Pines Acquisition on February 9, 2011, incremental revenues attributable to capacity expansions (including additional working gas of approximately 17 Bcf and 9 Bcf in the aggregate at our Pine Prairie and Southern Pines facilities during 2012 and 2011, respectively) and results of PNG Marketing, LLC (our commercial optimization company). See Results of Operations for further discussion and analysis of our operating results. Expansion capital expenditures for the nine months ended September 30, 2012 were approximately $47.4 million.

Results of Operations

The tables below summarize our results of operations for the periods indicated (in thousands, except working capacity and monthly operating metrics data):

Table of Contents

	Three Months Ended September 30, 2012		2011		Favorable/(Unfavorable) Variance (1) $	%
Revenues						
Firm storage services	$	36,364	$	35,536	$ 828	2%
Hub services and merchant storage (2)		28,176		42,548	(14,372)	(34)%
Other		1,587		1,250	337	27%
Total revenues		66,127		79,334	(13,207)	(17)%
Storage-related costs - Hub services and merchant storage (3)		(26,012)		(41,507)	15,495	37%
Storage-related costs - Firm storage services (4)		(3,172)		(4,078)	906	22%
Field operating costs		(2,974)		(3,070)	96	3%
General and administrative expenses		(4,641)		(4,368)	(273)	(6)%
Other income/(expense), net		(5)		(7)		
Acquisition-related expense				5		
Insurance deductible related to property damage						
Equity compensation expense		1,016		681		
Mark-to-market of open derivative positions		(628)		(132)		
Adjusted EBITDA	$	29,711	$	26,858	$ 2,853	11%
Reconciliation to net income						
Adjusted EBITDA	$	29,711	$	26,858	$ 2,853	11%
Depreciation, depletion and amortization		(9,461)		(9,193)	(268)	(3)%
Interest expense, net of capitalized interest		(1,973)		(1,666)	(307)	(18)%
Equity compensation expense		(1,016)		(681)		
Acquisition-related expenses				(5)		
Mark-to-market of open derivative positions		628		132		
Net income	$	17,889	$	15,445	$ 2,444	16%
Operating Data:						
Net revenue margin(5)		36,315		33,617	2,698	
Field operating costs / G&A / Other		(6,604)		(6,759)	155	2%
Adjusted EBITDA	$	29,711	$	26,858	$ 2,853	11%
Average working storage capacity (Bcf)		89		75	14	19%
Monthly Operating Metrics ($/Mcf):						
Net revenue margin (5)	$	0.14	$	0.15	$ (0.01)	(7)%
Field operating costs / G&A / Other		(0.03)		(0.03)		
Adjusted EBITDA	$	0.11	$	0.12	$ (0.01)	

(1) Certain variance amounts and/or percentages were intentionally omitted.

(2) Includes revenues associated with sales of natural gas through commercial marketing activities.

(3) Includes costs associated with natural gas sold through commercial marketing activities and storage-related costs (including fuel expense) attributable to hub services and merchant storage revenues.

(4) Includes storage-related costs (including fuel expense) attributable to firm storage services revenues.

(5) Net revenue margin equals total revenues less storage-related costs and excludes the impact, if any, of mark-to-market adjustments (unrealized gains and losses) on open derivative positions.

26

Table of Contents

	Nine Months Ended September 30, 2012	2011	Favorable/(Unfavorable) Variance (1) $	%
Revenues				
Firm storage services	$ 105,646	$ 100,075	$ 5,571	6%
Hub services and merchant storage (2)	166,268	81,252	85,016	105%
Other	3,076	2,791	285	10%
Total revenues	274,990	184,118	90,872	49%
Storage-related costs - Hub services and merchant storage (3)	(157,564)	(77,830)	(79,734)	(102)%
Storage-related costs - Firm storage services (4)	(9,985)	(12,827)	2,842	22%
Field operating costs	(9,030)	(9,072)	42	
General and administrative expenses	(14,304)	(18,193)	3,889	21%
Other income/(expense), net	12	10		
Acquisition-related expense		4,055		
Insurance deductible related to property damage		500		
Equity compensation expense	3,148	3,339		
Mark-to-market of open derivative positions	(72)	(235)		
Adjusted EBITDA	$ 87,195	$ 73,865	$ 13,330	18%
Reconciliation to net income				
Adjusted EBITDA	$ 87,195	$ 73,865	$ 13,330	18%
Depreciation, depletion and amortization	(27,855)	(24,602)	(3,253)	(13)%
Interest expense, net of capitalized interest	(5,350)	(3,945)	(1,405)	(36)%
Equity compensation expense	(3,148)	(3,339)		
Acquisition-related expenses		(4,055)		
Mark-to-market of open derivative positions	72	235		
Insurance deductible related to property damage		(500)		
Net income	$ 50,914	$ 37,659	$ 13,255	35%
Operating Data:				
Net revenue margin(5)	$ 107,369	$ 93,226	$ 14,143	15%
Field operating costs / G&A / Other	(20,174)	(19,361)	(813)	4%
Adjusted EBITDA	$ 87,195	$ 73,865	$ 13,330	18%
Average working storage capacity (Bcf)	82	69	13	18%
Monthly Operating Metrics ($/Mcf):				
Net revenue margin (5)	$ 0.15	$ 0.15	$	
Field operating costs / G&A / Other	(0.03)	(0.03)		
Adjusted EBITDA	$ 0.12	$ 0.12	$	

(1) Certain variance amounts and/or percentages were intentionally omitted.

(2) Includes revenues associated with sales of natural gas through commercial marketing activities.

(3) Includes costs associated with natural gas sold through commercial marketing activities and storage-related costs (including fuel expense) attributable to hub services and merchant storage revenues.

(4) Includes storage-related costs (including fuel expense) attributable to firm storage services revenues.

(5) Net revenue margin equals total revenues less storage-related costs and excludes the impact, if any, of mark-to-market adjustments (unrealized gains and losses) on open derivative positions.

Non-GAAP and Segment Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses Adjusted EBITDA and distributable cash flow in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon

Table of Contents

which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. Adjusted EBITDA and/or distributable cash flow may exclude, for example, the impact of unique and infrequent items, items outside of management s control and/or items that are not indicative of our core operating results and business outlook, which we have defined hereinafter as selected items impacting comparability. These additional financial measures are reconciled to net income, the most directly comparable measures as reported in accordance with GAAP, in the following table and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

We define Adjusted EBITDA as earnings before interest expense, taxes, depreciation, depletion and amortization, equity compensation plan charges, unrealized gains and losses from derivative activities and applicable selected items impacting comparability.

Distributable cash flow, as determined by our general partner, is defined as: (i) net income; plus or minus, as applicable, (ii) any amounts necessary to offset the impact of any items included in net income that do not impact the amount of available cash; plus (iii) any acquisition-related expenses deducted from net income and associated with (a) successful acquisitions or (b) any other potential acquisitions that have not been abandoned; minus (iv) any acquisition related expenses covered by clause (iii)(b) immediately preceding that relate to (a) potential acquisitions that have since been abandoned or (b) potential acquisitions that have not been consummated within one year following the date such expense was incurred (except that if the potential acquisition is the subject of a pending purchase and sale agreement as of such one-year date, such one-year period of time shall be extended until the first to occur of the termination of such purchase and sale agreement or the first day following the closing of the acquisition contemplated by such purchase and sale agreement); and minus (v) maintenance capital expenditures. The types of items covered by clause (ii) above include (a) depreciation, depletion and amortization expense, (b) any gain or loss from the sale of assets not in the ordinary course of business, (c) any gain or loss as a result of a change in accounting principle, (d) any non-cash gains or items of income and any non-cash losses or expenses, including asset impairments, amortization of debt discounts, premiums or issue costs, mark-to-market activity associated with hedging and with non-cash revaluation and/or fair valuation of assets or liabilities and (e) earnings or losses from unconsolidated subsidiaries except to the extent of actual cash distributions received. Distributable cash flow does not reflect actual cash on hand that is available for distribution to our unitholders.

The following table reconciles Non-GAAP and segment financial measures to the most directly comparable measures as reported in accordance with GAAP (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Adjusted EBITDA reconciliation				
Net income	$ 17,889	$ 15,445	$ 50,914	$ 37,659
Interest expense, net of capitalized interest	1,973	1,666	5,350	3,945
Depreciation, depletion and amortization	9,461	9,193	27,855	24,602
Selected items impacting Adjusted EBITDA				
Equity compensation expense	1,016	681	3,148	3,339
Acquisition-related expenses		5		4,055
Mark-to-market of open derivative positions	(628)	(132)	(72)	(235)
Insurance deductible related to property damage				500
Adjusted EBITDA	**$ 29,711**	**$ 26,858**	**$ 87,195**	**$ 73,865**
Distributable cash flow reconciliation				
Net income	$ 17,889	$ 15,445	$ 50,914	$ 37,659
Depreciation, depletion and amortization	9,461	9,193	27,855	24,602
Acquisition-related expense		5		4,055
Maintenance capital expenditures	(84)	(51)	(457)	(266)

Other non cash items:				
Equity compensation expense, net of cash payments	1,141	683	2,595	2,722
Mark-to-market of open derivative positions	(628)	(132)	(72)	(235)
Distributable cash flow	**$ 27,779**	**$ 25,143**	**$ 80,835**	**$ 68,537**

Table of Contents

Three Months Ended September 30, 2012 as Compared to the Three Months Ended September 30, 2011

Revenues, Volumes and Related Costs. As noted in the table above, our total revenues net of storage-related costs increased during the three months ended September 30, 2012 (the 2012 period) when compared to the three months ended September 30, 2011 (the 2011 period). The primary reasons for such increase are the results of PNG Marketing, LLC (our commercial optimization company) and incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities. These and other significant variances related to these periods are discussed in more detail below:

- ***Firm storage services*** Firm storage services revenues did not change significantly in the 2012 period as compared to the 2011 period. Incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities were offset by decreased storage rates on contracts executed to replace expiring contracts on existing capacity and lower fuel in kind revenues, both of which resulted from lower natural gas prices throughout 2011 and into 2012. Also, additional working storage capacity was retained for use by our commercial optimization company in the 2012 period as compared to the 2011 period. Revenues generated through the use of storage capacity by our commercial optimization company are reflected as merchant storage revenues when natural gas we own is withdrawn from storage and sold.

- ***Hub services and merchant storage*** Hub services and merchant storage revenues (which include revenues from sales of natural gas by our commercial optimization company) decreased in the 2012 period as compared to the 2011 period. The primary reason for the decrease in 2012 as compared to 2011 is due to a decrease in volumes of natural gas sold by our commercial optimization company, in addition to a decline in natural gas prices in the 2012 period as compared to the 2011 period. The volume and timing of natural gas sales by our commercial optimization company are largely driven by market opportunities.

- ***Other*** Other revenues did not have a significant impact on the comparability of our operating results between the 2012 and the 2011 periods.

- ***Storage-related costs Hub services and merchant storage*** Hub services and merchant storage-related costs (which includes costs associated with natural gas sold by our commercial optimization company) decreased in the 2012 period as compared to the 2011 period. The primary reason for the decrease in the 2012 period as compared to the 2011 period is due to the decrease in volumes of natural gas sold by our commercial optimization company.

- ***Storage-related costs Firm storage services*** Firm storage services related costs decreased in the 2012 period as compared to the 2011 period. The decrease in the 2012 period as compared to the 2011 period is primarily due to a reduction in storage and transportation capacity leased from third parties along with lower fuel costs resulting from a decline in natural gas prices.

Other Costs and Expenses. The significant variances are discussed further below:

- ***Field operating costs*** Field operating costs did not change significantly in the 2012 period when compared to the 2011 period.

- ***General and administrative expenses*** General and administrative expenses did not change significantly in the 2012 period as compared to the 2011 period. Additionally, we recognized approximately $0.2 million and $0.5 million of equity compensation expense associated with transaction awards granted by PAA during the 2012 and 2011 periods, respectively. Although we will not bear the economic burden of these awards, we benefit from the services underlying these awards.

- ***Depreciation, depletion and amortization*** Depreciation, depletion and amortization expense increased in the 2012 period as compared to the 2011 period. The increase resulted primarily from an increased amount of depreciable assets resulting from capacity expansions at our Pine Prairie and Southern Pines facilities.

- ***Interest expense, net of capitalized interest*** Interest expense, net of capitalized interest, increased in the 2012 period when compared to the 2011 period. Interest expense, on a gross basis, decreased to approximately $3.5 million in the 2012 period as compared to approximately $4.4 million in the 2011 period due to lower average interest rates in the 2012 period as compared to the 2011 period and was partially offset by higher average debt balances in the 2012 period as compared to the 2011 period. Capitalized interest deceased from approximately $2.7 million in the 2011 period to approximately $1.6 million in the 2012 period. The decrease was primarily the result of lower average interest rates and an increase in working gas capacity in-service.

Table of Contents

Nine Months Ended September 30, 2012 as Compared to the Nine Months Ended September 30, 2011

Revenues, Volumes and Related Costs. As noted in the table above, our total revenues and storage-related costs increased during the nine months ended September 30, 2012 (the 2012 period) when compared to the nine months ended September 30, 2011 (the 2011 period). The primary reasons for such increase are the completion of the Southern Pines Acquisition on February 9, 2011, results of PNG Marketing, LLC, and incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities. These and other significant variances related to these periods are discussed in more detail below:

• ***Firm storage services*** Firm storage services revenues increased in the 2012 period as compared to the 2011 period primarily due to the completion of the Southern Pines Acquisition and incremental revenues attributable to the expansion of our working gas capacity at our Pine Prairie and Southern Pines facilities. These increases were partially offset by decreased storage rates on contracts executed to replace expiring contracts on existing capacity and lower fuel in kind revenues, both of which resulted from lower natural gas prices throughout 2011 and into 2012. Also, additional working storage capacity was retained for use by our commercial optimization company in the 2012 period as compared to the 2011 period. Revenues generated through the use of storage capacity by our commercial optimization company are reflected as merchant storage revenues when natural gas we own is withdrawn from storage and sold.

• ***Hub services and merchant storage*** Hub services and merchant storage revenues (which include revenues from sales of natural gas by our commercial optimization company) increased in the 2012 period as compared to the 2011 period. The primary reason for the increase in 2012 as compared to 2011 is due to an increase in volumes of natural gas sold by our commercial optimization company, partially offset by a decline in natural gas prices in the 2012 period as compared to the 2011 period. The volume and timing of natural gas sales by our commercial optimization company are largely driven by market opportunities.

• ***Other*** Other revenues did not have a significant impact on the comparability of our operating results between the 2012 and the 2011 periods.

• ***Storage-related costs Hub services and merchant storage*** Hub services and merchant storage-related costs (which includes costs associated with natural gas sold by our commercial optimization company) increased in the 2012 period as compared to the 2011 period. The primary reason for the increase in the 2012 period as compared to the 2011 period is due to the increase in volumes of natural gas sold by our commercial optimization company.

• ***Storage-related costs Firm storage services*** Firm storage services related costs decreased in the 2012 period as compared to the 2011 period. The decrease in the 2012 period as compared to the 2011 period is primarily due to a reduction in storage and transportation capacity leased from third parties along with lower fuel costs resulting from a decline in natural gas prices.

Other Costs and Expenses. The significant variances are discussed further below:

- ***Field operating costs*** Field operating costs did not change significantly in the 2012 period when compared to the 2011 period. Increases in operating expenses during the 2012 period associated with the Southern Pines Acquisition and facility expansions were approximately offset by $0.5 million of expense recognized during the 2011 period for the property insurance deductible related to the January 2011 operational incident and fire at our Bluewater facility.

- ***General and administrative expenses*** General and administrative expenses decreased in the 2012 period as compared to the 2011 period. The 2011 period includes approximately $4.1 million of acquisition-related costs associated with the Southern Pines Acquisition. Additionally, we recognized approximately $1.0 million and $2.4 million of equity compensation expense associated with transaction awards granted by PAA during the 2012 and 2011 periods, respectively. Although we will not bear the economic burden of these awards, we benefit from the services underlying these awards.

- ***Depreciation, depletion and amortization*** Depreciation, depletion and amortization expense increased in the 2012 period as compared to the 2011 period. The increase resulted primarily from an increased amount of depreciable assets resulting from the Southern Pines acquisition and our internal capital expansion projects at our Pine Prairie and Southern Pines facilities. Additionally, amortization of intangible assets acquired in conjunction with the Southern Pines Acquisition was approximately $12.3 million and $10.6 million during the 2012 and 2011 periods, respectively.

Table of Contents

- ***Interest expense, net of capitalized interest*** Interest expense, net of capitalized interest, increased in the 2012 period when compared to the 2011 period. Interest expense, on a gross basis, decreased to approximately $11.4 million in the 2012 period as compared to approximately $12.4 million in the 2011 period due to lower average interest and was partially offset by higher average debt balances in the 2012 period as compared to the 2011 period. Capitalized interest deceased from approximately $8.4 million in the 2011 period to approximately $6.1 million in the 2012 period. The decrease was primarily the result of lower average interest rates and an increase in working gas capacity in-service.

Outlook

Overall market conditions during the three months ended September 30, 2012 for both hub services and firm storage services were comparable to those from the three months ended September 30, 2011. During the three months ended September 30, 2012, seasonal spreads (October to January) for 2012-2013, which are a proxy for the current intrinsic value of storage, ranged from $0.38 to $0.68, compared to $0.37 to $0.59 for the three months ended September 30, 2011. Over the past ten years, seasonal spreads ranged from $0.19-$4.74. Seasonal spreads for 2013-2014 and 2014-2015, which influence the rates at which we will be able to contract firm storage capacity in future years, have ranged from $0.35 to $0.47. Volatility levels, which impact the value we are able to realize on a short-term basis from our hub service and merchant storage activities, were higher during the three months ended September 30, 2012 than in the three months ended September 30, 2011. However, driven largely by the robust supply levels for natural gas, both in terms of natural gas storage inventory levels and the production from shale resources, recent increases in volatility levels have not resulted in a sizable increase in spread opportunities. In general, our outlook presumes that these fundamental trends will continue.

We believe our asset base, contract profile, financial position, low risk profile, and economically attractive expansion projects will enable us to substantially maintain our cash flows for the next several years in these current market conditions. Also, we are reasonably well positioned to develop low cost organic expansions and to acquire other assets if favorable market conditions exist. However, if gas storage market conditions decline further, in addition to adversely affecting hub services activities, they may also adversely impact the lease rates our customers are willing to pay for firm storage services with respect to new capacity under construction, as well as renewals of existing capacity upon expirations of existing term leases, many of which are at rates above current market levels. Accordingly, although a significant portion of our existing capacity is underpinned by multi-year firm storage contracts, we can provide no assurance that our operating and financial results will not be adversely impacted by adverse overall market conditions. In addition, we can provide no assurances that our organic growth and acquisition efforts will be successful.

Liquidity and Capital Resources

Overview

Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to storage costs incurred, natural gas purchases and other operating and general and administrative expenses, interest payments on our outstanding debt and distributions to our owners, (ii) maintenance and expansion capital expenditures, including purchases of base gas, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our short-term and long-term debt. We generally expect to fund our short-term cash requirements through our primary sources of liquidity, which consist of our cash flow generated from operations as well as borrowings under our credit facility. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit agreement, and/or proceeds from the issuance of additional equity or debt securities.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). Although the Dodd-Frank Act includes provisions regarding the use of financial instruments, and the scope and applicability of these provisions as implemented may continue to develop, our current assessment is that the direct effects of the Dodd-Frank Act on PNG will be limited to additional documentation and record-keeping requirements. We cannot, however, predict the effect the Dodd-Frank Act may have on the futures and capital markets, which may affect the depth and quality of our counterparties and lenders and, as a result, our liquidity and access to capital.

Credit Agreement

In August 2011, we entered into a senior unsecured credit agreement, which was amended in June 2012 (see Note 7 to the condensed consolidated financial statements for further discussion). As amended, the facility provides for (i) $350 million under a revolving credit facility, which may be increased at our option to $550 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the GO Bond Term Loans) pursuant to the purchase, at par, of the GO Bonds we acquired in conjunction with the Southern Pines Acquisition. The revolving credit facility expires in August 2016, unless

Table of Contents

extended. The purchasers of the two GO Bond Term Loans have the right to put, at par, to PNG the GO Bond Term Loans in August 2016, unless extended. The GO Bonds mature by their terms in May 2032 and August 2035, respectively.

Our credit agreement contains covenants and events of default. Our credit agreement restricts, among other things, our ability to make distributions of available cash to unitholders if any default or event of default, as defined in the credit agreement, exists or would result therefrom. In addition, the credit agreement contains restrictive covenants, including those that restrict our ability to grant liens, incur additional indebtedness, engage in certain transactions with affiliates, engage in substantially unrelated businesses, sell substantially all of our assets or enter into a merger or consolidation, and enter into certain burdensome agreements. In addition, the credit agreement contains certain financial covenants which, among other things, require us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 5.00 to 1.00 on outstanding debt (5.50 to 1.00 during an acquisition period) and also require that we maintain an EBITDA-to-interest coverage ratio that will not be less than 3.00 to 1.00, as such terms are defined in the credit agreement.

At September 30, 2012, borrowings of approximately $375.4 million were outstanding under our credit agreement, which includes approximately $175.4 million under the revolving credit facility. Additionally, we had approximately $1.8 million of outstanding letters of credit under our revolving credit facility. As of September 30, 2012, we were in compliance with the covenants, including the financial ratios, contained in our credit agreement. Based on the most restrictive covenant, at September 30, 2012 our incremental borrowing ability under our credit agreement was limited to approximately $152 million. Notably, the restriction on debt incurrence does not limit our ability to incur hedged inventory debt. Also, the formula for determining EBITDA in the context of the financial ratios allows for inclusion of pro forma EBITDA arising from certain capital investments, including for acquisitions and certain capital expenditures related to our Pine Prairie and Southern Pines expansions. We believe our credit facility and available debt capacity is adequate to fund our current capital program.

PAA Financial Support

PAA may elect, but is not obligated, to provide financial support to us under certain circumstances, such as in connection with an acquisition or expansion capital project. Our partnership agreement contains provisions designed to facilitate PAA s ability to provide us with financial support while reducing concerns regarding conflicts of interest by defining certain potential financing transactions between PAA and us as fair to our unitholders. As further defined in our partnership agreement, potential PAA financial support can include, but is not limited to, our issuance of common units to PAA, our borrowing of funds from PAA or guarantees or trade credit support to support the ongoing operations of us or our subsidiaries. We have no obligation to seek financing or support from PAA or to accept such financing or support if offered to us. As of September 30, 2012, outstanding parental guarantees issued by PAA to third parties on behalf of PNG Marketing were approximately $15 million. No amounts were due to PAA as of September 30, 2012 under such guarantees and no payments were made to PAA under such guarantees during the nine months ended September 30, 2012.

Sources of Liquidity

Our current sources of liquidity include:

- cash generated from operations;

- borrowings under our credit agreement;
- issuances of additional partnership units; and
- debt offerings.

We believe that cash generated from these sources will be sufficient to meet our short-term working capital requirements, long-term capital expenditure requirements, and quarterly cash distributions to unitholders.

We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $1.0 billion of debt or equity securities (Traditional Shelf). We have not issued any securities under the Traditional Shelf.

To maintain our targeted credit profile, we generally intend to fund approximately 60% of the capital required for future expansion projects (beyond the projects currently under development) with a combination of additional equity and retained cash flow in excess of distributions.

Table of Contents

For a discussion of the impact that the price of natural gas might have on our operations and liquidity and capital resources, see Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Working Capital

Working capital, defined as the amount by which current assets exceed current liabilities, is an indication of our liquidity and potential need for short-term funding. Our working capital requirements are driven primarily by changes in accounts receivable and accounts payable, natural gas inventory balances and short-term debt. These changes are primarily affected by factors such as credit extended to, and the timing of collections from, our customers, timing differences between the acquisition and sale of natural gas inventory (including cash settlement and margin requirements on related derivative instruments) and our level of spending for maintenance and expansion activity. As of September 30, 2012 we had a working capital deficit of approximately $32.5 million.

Historical Cash Flow Information

The following table presents a summary of our cash flows for the nine months ended September 30, 2012 and 2011 (in thousands):

	Nine Months Ended September 30,	
	2012	**2011**
Net cash provided by (used in):		
Operating activities	$ 68,913	$ 63,027
Investing activities	(43,723)	(787,163)
Financing activities	(25,238)	724,132
Net increase/(decrease) in cash	$ (48)	$ (4)
Adjusted EBITDA	$ 87,195	$ 73,865

Operating Activities. The primary drivers of cash flow from our operations are (i) the collection of amounts related to the storage and sales of natural gas, and (ii) the payment of amounts related to purchases of natural gas and expenses, principally storage and transportation related costs, field operating costs and general and administrative expenses. Cash provided by operating activities is significantly impacted in periods where we are increasing or decreasing the amount of inventory in storage. In the month that we pay for stored natural gas, we borrow under our credit facility to pay for the natural gas, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored natural gas. Cash from operating activities is also impacted in a similar manner by the timing of cash settlement of derivatives associated with physical purchases and sales of natural gas. Settlements of such derivatives are reflected as a component of accumulated other comprehensive income/(loss) until the applicable natural gas inventory is sold.

Investing Activities. Our investing activities for each of the periods listed above primarily relate to the continued expansion of our Pine Prairie and Southern Pines facilities and the acquisition of the related base gas required to operate the facilities. The 2011 period includes the Southern Pines Acquisition.

Financing Activities. Our financing activities primarily consist of (i) the payment of distributions to our unitholders and general partner, (ii) funding of capital expansion efforts (including organic growth projects and acquisitions) and (iii) borrowings and repayments under our credit agreement associated with inventory purchases and sales (including related derivatives) in conjunction with our merchant storage activities. The 2011 period includes borrowings and equity issuances associated with the funding of the Southern Pines Acquisition.

Capital Expenditures and Distributions to our Unitholders and General Partner

In addition to operating activities discussed above, we also use cash for our acquisition activities, purchases of natural gas inventory, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above.

Capital Expenditures. We currently forecast capital expansion expenditures for 2012 of approximately $59 million to $63 million (including capitalized interest), primarily related to the ongoing expansion of our Pine Prairie and Southern Pines facilities and the related base gas required to operate the facilities. Expansion capital expenditures for the nine months ended September 30, 2012

Table of Contents

were approximately $47.4 million. We expect to fund our capital expenditures with cash generated from operations and borrowings under our credit agreement. Additionally, we are forecasting approximately $0.6 million of maintenance capital expenditures in 2012, of which approximately $0.5 million was incurred through September 30, 2012.

Distributions to Unitholders and General Partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On November 14, 2012, we will pay a quarterly distribution of $0.3575 per unit on our common units and Series A subordinated units.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreement to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

See Note 12 to the condensed consolidated financial statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we lease storage and transportation capacity from third parties, incur debt and interest payments and enter into purchase commitments in conjunction with our operations and our capital expansion program. Additionally, we purchase natural gas from third parties for both commercial and operational purposes. We establish a margin on gas purchased for commercial purposes by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. The table below includes purchase obligations related to these activities. We do not expect to use a significant amount of internal capital on a long-term basis to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy.

The following table includes our best estimate of the amounts and timing of the payments due under our contractual obligations as of September 30, 2012 (in millions):

	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt, interest and fees(1)	$ 542.2	$ 5.4	$ 14.2	$ 14.2	$ 209.4	$ 299.1	$
	19.1	5.1	7.4	4.5	2.0		0.1

Storage / transportation agreements and leases														
Purchase obligations(2)		20.5		5.1		1.8		1.8		1.9		1.9		7.9
Other long-term liabilities		1.5		0.2		0.7		0.4		0.1		0.1		
Subtotal	$	583.3	$	15.8	$	24.1	$	20.9	$	213.4	$	301.1	$	8.0
Natural gas purchases (3)		214.8		62.0		120.4		23.3		5.1		4.0		
Total	$	798.1	$	77.8	$	144.5	$	44.2	$	218.5	$	305.1	$	8.0

(1) Includes interest payments and commitment fees on our senior unsecured credit agreement and note payable to PAA.

(2) Primarily includes amounts related to utility contracts and capital expansion activities.

(3) Amounts are based on estimated volumes and market prices of committed obligations as of September 30, 2012. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit and Parental Guarantees. Our $550 million senior unsecured credit agreement provides us with the ability to issue letters of credit. In connection with our use of certain leased storage and transportation assets and the purchase of natural gas by our commercial optimization company, we have periodically provided certain suppliers and counterparties with irrevocable standby letters of credit to secure our obligations for such purchases. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our consolidated balance sheet in the month the services are provided or when we take delivery of the natural gas purchased. In certain instances, parental guarantees have been provided by PAA in lieu of letters of credit. As of September 30, 2012, we had approximately $1.8 million of outstanding letters of credit under our credit agreement. Additionally, approximately $15 million of parental guarantees issued by PAA on behalf of PNG Marketing were outstanding as of September 30, 2012.

Table of Contents

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Recent Accounting Pronouncements

See Note 2 to the condensed consolidated financial statements.

Critical Accounting Policies and Estimates

For discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2011 Annual Report on Form 10-K.

Forward-Looking Statements

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- a continuation of reduced volatility and/or lower spreads in natural gas markets for an extended period of time;
- factors affecting demand for natural gas storage services and the rates we are able to charge for such services, including the balance between the supply of and demand for natural gas;
- our ability to maintain or replace expiring storage contracts, or enter into new storage contracts, in either case at attractive rates and on otherwise favorable terms;

- factors affecting our ability to realize revenues from hub services and merchant storage transactions involving uncontracted or unutilized capacity at our facilities;
- operational, geologic or other factors that affect the timing or amount of crude oil and other liquid hydrocarbons that we are able to produce in conjunction with the operation of our Bluewater facility;
- market or other factors that affect the prices we are able to realize for crude oil and other liquid hydrocarbons produced in conjunction with the operation of our Bluewater facility;
- our ability to obtain and/or maintain all permits, approvals and authorizations that are necessary to conduct our business and execute our capital projects;
- the impact of operational, geologic and commercial factors that could result in an inability on our part to satisfy our contractual commitments and obligations, including the impact of equipment performance, cavern operating pressures, cavern temperature variances, salt creep and subsurface conditions or events;
- risks related to the ownership, development and operation of natural gas storage facilities;
- failure to implement or execute planned internal growth projects on a timely basis and within targeted cost projections;
- the effectiveness of our risk management activities;
- the effects of competition;
- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;

Table of Contents

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns;
- the successful integration and future performance of acquired assets or businesses;
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- shortages or cost increases of supplies, materials or labor;
- weather interference with business operations or project construction;
- our ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- the operations or financial performance of assets or businesses that we acquire;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- increased costs or unavailability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plan; and

- other factors and uncertainties inherent in the ownership, development and operation of natural gas storage facilities.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risk Factors discussed in Item 1A of our 2011 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. Quantitative and Qualitative Disclosures about Market Risk

We are exposed to various market risks, including commodity price risk and interest rate risk. We use various derivative instruments to manage such risks. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring exchange cleared positions, as well as physical volumes, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We utilize natural gas derivatives to hedge commodity price risk inherent in our operations. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory and to manage our anticipated base gas requirements and storage capacity utilization associated with natural gas or the related storage of natural gas. We manage these exposures with various instruments, including exchange-cleared futures, swaps and options. See Note 11 to our condensed consolidated financial statements for further discussion regarding our hedging strategies and objectives.

Table of Contents

Interest Rate Risk

We utilize interest rate derivatives to hedge interest rate risk associated with our variable rate debt. Our objective for these derivatives is to hedge the cash flow variability associated with our interest payments as a result of market fluctuations in interest rates. We manage these exposures with over-the-counter, LIBOR-based interest rate swaps. See Note 11 to our condensed consolidated financial statements for further discussion regarding our hedging strategies and objectives.

The fair value of our derivatives as of September 30, 2012 and the change in fair value that would be expected from a 10% price/rate increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Increase (1)	Effect of 10% Decrease (1)
Natural gas derivatives	$ 10.6	$ (4.5)	$ 4.3
Interest rate derivatives	$ (1.0)	$ 0.1	$ (0.1)

(1) Positive numbers reflect an increase in fair value and negative numbers reflect a decrease in fair value.

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Commodity and interest rate sensitivities were calculated by assuming an across-the-board 10% increase or decrease. In the event of an actual 10% change in near-term commodity prices or interest rates, the fair value of our derivative portfolio would typically change less than that shown in a table, as commodity prices and interest rates do not typically change in a linear fashion.

Item 4. Controls and Procedures

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is (i) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Changes in Internal Control over Financial Reporting

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

Table of Contents

PART II.
OTHER INFORMATION

Item 1. Legal Proceedings

We are not a party to any legal proceeding other than legal proceedings arising in the ordinary course of our business. See Note 12 to the condensed consolidated financial statements for additional discussion regarding legal proceedings.

Item 1A. Risk Factors

For a discussion regarding our risk factors, see Item 1A of our 2011 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

Table of Contents

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.

	PAA NATURAL GAS STORAGE, L.P.			
	By:	PNGS GP LLC, its general partner		
Date: November 7, 2012	By:	/s/ GREG L. ARMSTRONG		
		Name:	Greg L. Armstrong	
		Title:	Chairman and Chief Executive Officer (Principal Executive Officer)	
Date: November 7, 2012	By:	/s/ DEAN LIOLLIO		
		Name:	Dean Liollio	
		Title:	President	
Date: November 7, 2012	By:	/s/ AL SWANSON		
		Name:	Al Swanson	
		Title:	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	

Table of Contents

EXHIBIT INDEX

3.1	Certificate of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
3.2	Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. dated August 16, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on August 20, 2010).
3.3	Amendment No. 1 dated February 2, 2012 to Second Amended and Restated Agreement of Limited Partnership of PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 8, 2012).
3.4	Certificate of Formation of PNGS GP LLC (incorporated by reference to Exhibit 3.3 to the Registration Statement on Form S-1 (333-164492) filed on January 25, 2010).
3.5	Amended and Restated Limited Liability Company Agreement of PNGS GP LLC dated May 5, 2010 (incorporated by reference to Exhibit 3.4 to the Quarterly Report on Form 10-Q filed on August 6, 2010).
31.1*	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2*	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1*	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350.
32.2*	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith.