PAA NATURAL GAS STORAGE LP
Form 8-K
August 03, 2011

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of

The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) **August 3, 2011**

PAA Natural Gas Storage, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-34722**	**27-1679071**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1500, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

Registrant s telephone number, including area code: **(713) 646-4100**

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated August 3, 2011.

Item 2.02 and Item 7.01. Results of Operations and Financial Condition; Regulation FD Disclosure

PAA Natural Gas Storage, L.P. (the Partnership) today issued a press release reporting its second quarter 2011 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01, we are providing updated detailed guidance for financial performance for the third and fourth quarters of calendar 2011. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under Item 2.02 and Item 7.01 shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Third Quarter and Fourth Quarter 2011 Guidance

Adjusted EBITDA (as defined below in Note 1 to the Operating and Financial Guidance table) is a financial measure used by our chief operating decision maker to evaluate our performance. In Note 9 below, we reconcile Adjusted EBITDA to net income for the 2011 guidance periods presented. We encourage you to visit our website at *www.pnglp.com* (in particular the section entitled Non-GAAP Reconciliations), which presents a historical reconciliation of Adjusted EBITDA and certain commonly used non-GAAP financial measures. We present Adjusted EBITDA because it is a measure used by management to evaluate performance and because we believe it provides additional information with respect to both the performance of our fundamental business activities and our ability to meet our future debt service, capital expenditures and working capital requirements. We believe that Adjusted EBITDA is used to assess our operating performance compared to other publicly traded partnerships in the midstream energy industry, without regard to financing methods, capital structure or historical cost basis. In addition, we have highlighted the impact of (i) equity compensation expense, (ii) insurance deductible related to property damage incident, (iii) acquisition-related expenses and (iv) mark-to-market of open derivative positions as such items affect EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three-month period ending September 30, 2011 and the three-month and twelve-month periods ending December 31, 2011 includes the anticipated impact of the timing of repairs to the damage sustained to certain treating equipment at our Bluewater facility on January 12, 2011, as well as other assumptions and estimates that we believe are reasonable given our assessment of historical trends (modified for changes in market conditions), business cycles and other reasonably available information. Projections contemplate inter-period changes in future performance resulting from a variety of factors we believe to be relevant, including new expansion projects, changes in our portfolio of storage and services contracts, the seasonal and dynamic nature of our business, and other market and competitive factors influencing the demand for storage services. Our projections do not include forecasts with respect to potential gains or losses on derivative financial instruments as we do not believe that there is an accurate way to forecast such activity. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so we can provide no assurance that actual performance will fall within the guidance ranges. Please refer to information under the caption Forward-Looking Statements and Associated Risks below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of August 2, 2011. We undertake no obligation to publicly update or revise any forward-looking statements.

PAA Natural Gas Storage, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual 6 Months Ended 6/30/11	Guidance (1) 3 Months Ending September 30, 2011 Low	3 Months Ending September 30, 2011 High	3 Months Ending December 31, 2011 Low	3 Months Ending December 31, 2011 High	12 Months Ending December 31, 2011 Low	12 Months Ending December 31, 2011 High
Net Revenues							
Firm storage services	$ 64.5	$ 35.7	$ 36.1	$ 36.1	$ 36.3	$ 136.3	$ 136.9
Hub services	4.6	0.3	1.2	2.0	2.3	6.9	8.1
Proprietary capacity margins, net	1.3			3.0	3.3	4.3	4.6
Other	1.5	0.7	1.4	1.5	1.7	3.7	4.6
Total net revenues	72.1	36.7	38.7	42.6	43.6	151.4	154.4
Storage related costs	(10.1)	(3.6)	(3.2)	(3.9)	(3.7)	(17.6)	(17.0)
Other operating costs (except those shown below)	(6.0)	(3.6)	(3.2)	(3.2)	(3.0)	(12.8)	(12.2)
Fuel expense	(2.2)	(1.5)	(0.8)	(1.5)	(1.2)	(5.2)	(4.2)
General and administrative expenses	(13.8)	(5.1)	(4.6)	(5.0)	(4.7)	(23.9)	(23.1)
Depreciation, depletion and amortization	(15.4)	(9.2)	(8.8)	(9.2)	(8.8)	(33.8)	(33.0)
Total costs and expenses	**(47.6)**	**(23.0)**	**(20.6)**	**(22.8)**	**(21.4)**	**(93.4)**	**(89.6)**
Operating income	**24.5**	**13.7**	**18.1**	**19.8**	**22.2**	**58.0**	**64.8**
Interest expense, net of capitalized interest	(2.3)	(2.2)	(1.9)	(2.4)	(2.1)	(6.9)	(6.3)
Other income (expense), net	0.0					0.0	0.0
Net income	**$ 22.2**	**$ 11.5**	**$ 16.2**	**$ 17.4**	**$ 20.1**	**$ 51.1**	**$ 58.5**
Net income available to limited partners	$ 21.6	$ 11.2	$ 15.8	$ 16.4	$ 19.0	$ 49.2	$ 56.5
Net Income Per Limited Partner Unit (basic and diluted) (2,3)							
Weighted Average Units Outstanding	65.3	71.1	71.1	71.1	71.1	69.7	69.7
Net income Per Limited Partner Unit	$ 0.33	$ 0.16	$ 0.22	$ 0.23	$ 0.27	$ 0.71	$ 0.81
EBITDA	**$ 39.9**	**$ 22.9**	**$ 26.9**	**$ 29.0**	**$ 31.0**	**$ 91.8**	**$ 97.8**
Selected Items Impacting Comparability							
Equity compensation expense	$ (2.7)	$ (1.1)	$ (1.1)	$ (1.0)	$ (1.0)	$ (4.8)	$ (4.8)
Insurance deductible related to property damage incident	(0.5)					(0.5)	(0.5)
Acquisition-related expenses	(4.1)					(4.1)	(4.1)
Mark-to-market of open derivative positions	0.1					0.1	0.1
	$ (7.1)	$ (1.1)	$ (1.1)	$ (1.0)	$ (1.0)	$ (9.2)	$ (9.2)
Excluding Selected Items Impacting Comparability							
Adjusted EBITDA	$ 47.0	$ 24.0	$ 28.0	$ 30.0	$ 32.0	$ 101.0	$ 107.0
Adjusted Net Income	$ 29.3	$ 12.6	$ 17.3	$ 18.4	$ 21.1	$ 60.3	$ 67.7
Adjusted Basic Net Income per Limited Partner Unit (2,3)	$ 0.44	$ 0.17	$ 0.24	$ 0.24	$ 0.28	$ 0.85	$ 0.96

(1) Amounts may not recalculate due to rounding.

(2) Our outstanding limited partner interests as of June 30, 2011 consisted of 59.2 million common units, 11.9 million Series A subordinated units and 13.5 million Series B subordinated units. Series B subordinated units are not entitled to cash distributions unless and

until they convert to Series A subordinated units or common units, which conversion is contingent on our meeting both certain distribution levels and certain in-service operational requirements at our Pine Prairie facility. As a result, the Series B subordinated units are not included in the calculation of basic or diluted net income per unit amounts.

(3) Net income per unit has been calculated in accordance with FASB s requirement that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized within the earnings per unit calculation.

Notes and Significant Assumptions:

1. *Definitions.*

EBITDA	Earnings before interest, taxes and depreciation, depletion and amortization.
Adjusted EBITDA	EBITDA excluding selected items impacting comparability.
FASB	Financial Accounting Standards Board
Bcf	Billion cubic feet
Mcf	Thousand cubic feet
LTIP	Long-Term Incentive Plan
PAA	Plains All American Pipeline, L.P. (NYSE: PAA), the owner of our general partner, as well as a majority of our limited partner interests.
General partner (GP)	As the context requires, general partner or GP refers to any or all of (i) PNGS GP LLC, the owner of our 2% general partner interest and incentive distribution rights and (ii) PAA, the sole member of PNGS GP LLC.

2. *Business Overview*. Our business consists of the acquisition, development, operation and commercial management of natural gas storage facilities. We provide natural gas storage services to a broad mix of customers, including local gas distribution companies (LDCs), electric utilities, pipelines, direct industrial users, electric power generators, marketers, producers, LNG importers and affiliates of such entities. Our storage rates are regulated under Federal Energy Regulatory Commission, or FERC, rate-making policies, which currently permit our facilities to charge market-based rates for our services. We own and operate three natural gas storage facilities located in Louisiana, Mississippi and Michigan. From time to time, we also lease storage capacity and pipeline transportation capacity from third parties in order to increase our operational flexibility and enhance the services we offer our customers. Acquisitions are expected to constitute an important element of our growth strategy; however, the accompanying detailed financial guidance does not include any forecasts for acquisitions.

We generate revenue primarily from fee-based gas storage services to our customers, which include both firm storage services and hub services. We also generate a portion of our net revenues from other sources as described below in other net revenues.

- *Firm Storage Services*. Firm storage services include (i) storage services pursuant to which customers receive the assured or firm right to store gas in our facilities over a multi-year period and (ii) seasonal park and loan services pursuant to which customers receive the firm right to store gas in (park), or borrow gas from (loan), our facilities on a seasonal basis. Under our firm storage contracts, our customers are obligated to pay us fixed monthly capacity reservation fees, which are owed to us regardless of the actual storage capacity utilized. Firm storage services also include cycling fees based on the volume of natural gas nominated for injection and/or withdrawal as well as a small portion of natural gas nominated for injection that we retain as compensation for our fuel use (see fuel expense below). For the 2011/2012 storage season beginning April 1, 2011, approximately 95% of our owned and leased storage capacity is contracted. Our revenue guidance for firm storage services is based primarily on the service fees provided for under such existing contracts and the service fees provided for under any existing seasonal park and loan contracts. Certain components of our firm storage services revenue, such as cycling fees and fuel compensation, are dependent on the injection and withdrawal actions of our individual customers, both from a timing and volume perspective. A meaningful portion of revenues associated with fuel collections are offset by fuel related expenses (see discussion of Fuel expense). Timing differences between forecasted activity and actual activity may result in a shifting of revenues between individual quarterly periods within a given storage season. Throughput differences may result in our ultimate realization of revenues being different from our forecasted amounts.

- *Hub Services*. We also generate revenue from the provision of hub services at our facilities. Our capacity to provide hub services is primarily dependent on our outstanding obligations to customers under firm storage services contracts. As a result, increases in our firm storage services obligations may result in certain limitations in our ability to provide hub services and vice versa. Hub services include (i) interruptible storage services pursuant to which customers receive only limited assurances regarding the availability of capacity in our storage facilities and pay fees based on their actual utilization of our assets, (ii) non-seasonal park and loan services and (iii) wheeling and balancing services pursuant to which customers pay fees for the right to move a volume of gas through our facilities from one interconnection point to another and true up their deliveries of gas to, or takeaways of gas from, our facilities. A portion of revenues related to these activities may include fuel collections which are offset by fuel related expenses (see discussion of Fuel expense below). Such activities are generally short-term in nature and the timing is influenced by weather, operating disruptions, foreign import activities and other conditions that result in temporary disruptions in supply and demand. Additionally, our wheeling and balancing activities are also influenced by certain market conditions such as location price differentials and other competing sources of transportation capacity. Accordingly, providing guidance on the overall amount and timing of revenue from these activities is less precise than guidance associated with firm storage services and thus we have provided for a wider range of potential performance on a relative basis during any given guidance period. Our overall revenue guidance for hub services is based on assumptions and estimates for an annual period that we believe are reasonable given our assessment of historical trends (modified for changes in market conditions) and other reasonably available information.

- *Proprietary capacity margins, net.* A portion of our net revenue guidance includes net margin expected to be realized by our commercial group. This net margin consists of revenue generated through the purchase and sale of natural gas net of any storage related costs incurred. Our guidance is based on certain assumptions regarding expected margin to be achieved on approximately 5.5 Bcf of uncontracted space, representing approximately 7% of total owned working gas storage capacity. Such activities may not generate the forecasted level or, even if achieved, may not result in ratable realizations throughout the balance of the year.

- *Other Revenues*. We also generate revenues through the sale of crude oil and liquids produced in conjunction with the operation of our Bluewater facility, net of royalties and taxes. Due to injection and withdrawal cycles and related reservoir pressure considerations, we anticipate crude oil and liquids production will occur disproportionately in the first quarter of each year, a lesser amount in the second quarter and the balance over the third and fourth quarters of each year. Revenues from sales of crude oil and liquids are also impacted by changes in market prices. Our revenue guidance for these activities reflects our estimates of likely production and our estimate of a net realizable price at the time of sale. Additionally, we periodically sell any fuel-in-kind volumes in excess of actual volumes needed as fuel to operate facilities and reflect any gain or loss on such sales.

- *Bluewater Incident.* Certain equipment was damaged at the gas handling portion of the Bluewater facility in January 2011. The incident was limited to the portion of Bluewater s gas handling facility that removes liquids from natural gas that is withdrawn from one of the two offsite storage reservoirs at Bluewater before it is injected into pipelines for transportation. We do not believe the damage will have a material impact on our ability to meet customer commitments at Bluewater. Reconstruction of the damaged portion of the gas handling facilities, which are generally utilized on a limited basis during the summer months, is expected to be completed by the fourth quarter at an estimated cost of approximately $4.8 million before insurance.

The following table summarizes our Adjusted EBITDA guidance for the forecasted periods, average owned working natural gas storage capacities and operating metrics.

	Actual 6 Months Ended Jun. 30, 2011	Guidance(1)(2) 3 Months Ending Sep. 30, 2011	3 Months Ending Dec. 31, 2011	12 Months Ending Dec. 31, 2011
	(dollars in millions)			
Total net revenues	$ 72.1	$ 37.7	$ 43.1	$ 152.9
Storage related costs / Other	(10.2)	(3.4)	(3.8)	(17.4)
Net Revenue Margin	61.8	34.3	39.3	135.4
Operating costs / G&A / Other	(14.8)	(8.3)	(8.3)	(31.4)
Adjusted EBITDA	$ 47.0	$ 26.0	$ 31.0	$ 104.0
Average Total Owned Working Storage Capacity (Bcf)	67	75	75	71
Average Monthly Operating Metrics ($/Mcf)				
Net Revenue Margin	$ 0.15	$ 0.15	$ 0.17	$ 0.16
Operating costs / G&A / Other	(0.03)	(0.04)	(0.04)	(0.04)
Adjusted EBITDA	$ 0.12	$ 0.12	$ 0.14	$ 0.12

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(1) Excluding selected items impacting comparability,

(2) Mid-point of guidance.

Net Revenue Margin is total net revenues less storage related costs. Storage related costs consist of fees incurred to lease third-party storage and pipeline capacity and transaction costs associated with managing injection and deliverability capacity at our facilities. Costs associated with our leased pipeline capacity are subject to variation as the terms of these agreements typically contain certain fees which fluctuate based on actual volumes shipped in addition to monthly reservation fees. Our revenues generated through the use of leased assets, which are typically limited to a margin, are not significant to our results of operations when compared to activities generated from the assets which we own. Additionally, we enter into loans of our base gas to provide us greater flexibility in providing firm storage services and hub services. Costs incurred to enter into seasonal loan agreements are reflected as a component of storage related costs in our detailed guidance. Storage related costs are subject to fluctuation based on both the amount and timing of loan agreements we enter into and certain timing differences may occur between the recognition of costs associated with these loans and the corresponding firm storage services or hub services revenues generated from the operational flexibility provided by these loans.

Our primary expense components related to gas storage services comprise fuel expense, operating costs and general and administrative expense.

• *Fuel expense.* Natural gas is the primary fuel for our compressors, which are used to inject natural gas into our storage facilities and to boost the pressures for certain pipeline deliveries or transfers. Fuel-related expense may fluctuate materially from period to period due to variations in both the volume and value of natural gas consumed in our operations, with volumes being driven primarily by the volumes of natural gas injected into or wheeled through our facilities. During an annual cycle, we generally collect sufficient quantities of fuel from our customers through our cycling collections and hub services activities to offset the amount of fuel we consume (see revenue descriptions above), therefore our fuel expense is principally offset by fuel related revenue on an annual basis. However, the fuel consumed and collected may not be equivalent on a quarterly basis. Fuel expense is also impacted by our ability to maximize the efficiency of our operation of our facilities. We charge fuel expense for the estimated volume consumed based on the weighted average price of fuel collected. Actual fuel revenue generated and consumed will vary with customer activity and may be influenced by weather and other factors.

• *Operating Costs.* Excluding fuel-related expenses, our operating costs typically do not materially vary based on the amount of natural gas we store. The timing of certain expenditures during a year generally fluctuates with customers demands, which change depending on market conditions and whether we are in the injection or withdrawal season for natural gas.

• *General and Administrative Expense / Other Income (Expense).* For guidance purposes, we anticipate we will routinely incur annual third party acquisition expenses. In accordance with Section 805 of the FASB s Accounting Standards

Codification, effective in 2009, we are required to expense costs related to acquisition evaluations as incurred, regardless of the success of such acquisition efforts. Accordingly, from time to time we may incur general and administrative expenses related to our acquisition efforts in excess of such guidance amounts. To the extent considered meaningful, such excess amounts will be classified as a selected item impacting comparability and thus excluded from Adjusted EBITDA, as such costs do not impact the operations of our existing assets and may benefit future periods. For the twelve-month period ending December 31, 2011, our forecast includes $4.1 million of SG Resources acquisition related costs.

3. *Depreciation, Depletion and Amortization.* We forecast depreciation, depletion and amortization based on our existing assets, unamortized deferred debt costs, forecasted capital expenditures and projected in-service dates.

4. *Capital Expenditures.* Excluding any potential acquisitions that we may commit to after the date hereof, we forecast capital expenditures (net of estimated insurance and other reimbursements) during calendar 2011 to be approximately $100 million for expansion projects (including capitalized interest) with an additional $0.8 million for maintenance capital projects. During the first six months of 2011, we spent $45.1 million and $0.2 million, respectively, for expansion and maintenance projects. Following is a breakdown by facility of our forecasted expansion capital expenditures for the year ending December 31, 2011:

	Calendar 2011 (in millions)		
Expansion Capital (including base gas)			
• Pine Prairie			$55.0
• Southern Pines			39.0
• Bluewater			6.0
			100.0
Potential Adjustments for Timing / Scope Refinement (1)	- $4.0		+ $2.0
Total Projected Capital Expenditures (excluding acquisitions)	$96.0	-	$102.0
Maintenance Capital		$0.8	

(1) Potential variation to current facility capital cost estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as regulatory approvals and weather.

5. *Capital Structure*. This guidance is based on our capital structure as of June 30, 2011.

6. *Interest Expense, net.* Debt balances, including a three-year, 5.25% $200 million unsecured term loan with PAA related to the SG Resources acquisition, are projected based on estimated (i) operating cash flows, (ii) capital expenditures for expansion / maintenance projects and base gas purchases, (iii) working capital sources and uses and (iv) distribution payments. Interest rate assumptions for variable rate debt are based on the current forward LIBOR curve. Also included in interest expense are interest rate swap accruals, commitment fees, and other financing costs. Interest expense is net of amounts capitalized for major expansion capital projects.

7. *Reconciliation of Net Income to DCF*. The following table reconciles the mid-point of Net Income to distributable cash flow for the three-month period ending September 30, 2011 and the three-month and twelve-month periods ending December 31, 2011.

	Actual 6 months ended Jun. 30, 2011	3 months ending Sep. 30, 2011	Mid-Point Guidance 3 months ending Dec. 31, 2011 (in millions)	12 months ending Dec. 31, 2011
Net Income	$ 22.2	$ 13.9	$ 18.8	$ 54.8
Depreciation, depletion, amortization	15.4	9.0	9.0	33.4
Equity compensation expense, net of cash payments	2.0	1.1	0.9	3.9
Maintenance capital expenditures	(0.2)	(0.3)	(0.3)	(0.8)
Acquisition-related expenses	4.1			4.1
Mark-to-market of open derivative positions	(0.1)			(0.1)
DCF	$ 43.4	$ 23.6	$ 28.3	$ 95.3

8. *Equity Compensation Plans*. The majority of our outstanding equity compensation awards contain vesting criteria that are based either on (i) the later to occur of a specified date, or the date upon which a specified PNG distribution level is attained, or (ii) the conversion of our Series A and Series B subordinated units. For the majority of our outstanding equity compensation awards as of June 30, 2011, estimated vesting dates range from August 2011 to August 2014 and annualized PNG distribution levels for the same time period range from $1.44 to $1.90. The majority of these awards are classified as equity awards for accounting purposes and thus the compensation expense recognized over the service period is based on the fair value of the awards on the grant date and is generally not subject to re-measurement prior to vesting. Upon vesting, our equity classified awards will result in the issuance of PNG common units.

During September 2010, certain officers of PAA were granted approximately 375,000 Transaction Grants denominated in PNG common units, Series A subordinated units, and Series B Subordinated units. The awards will vest upon the completion of the service period and certain performance conditions including the conversion of PNG s Series A subordinated units into common units of PNG and the conversion of PNG s Series B subordinated units into Series A subordinated units of PNG. Upon vesting, these awards will be settled with outstanding common or Series A subordinated units of PNG currently owned by PAA. Although PNG does not bear the economic burden of these awards, since the services these officers provide benefit PNG, we are required to reflect the expense associated with these awards in our financial statements. Our forecasts for the three months ending September 30, 2011 and December 31, 2011 reflect expense of approximately $0.6 million and $0.6 million, respectively, associated with these awards.

We have previously determined that an annualized distribution of $1.45, the conversion of our Series A subordinated units, and the conversion of the first tranche of the Series B subordinated units are probable of occurring in the foreseeable future. Therefore, for awards that vest upon annualized distribution levels of $1.45 or less, our guidance includes compensation expense accruals over the service period of the respective awards. The actual amount of equity compensation expense for any given period can vary as a result of future changes to our probability assessments relative to the performance conditions required for vesting and as a result of changes to our outstanding awards, such as granting additional awards or forfeitures.

9. *Reconciliation of Net Income to Adjusted EBITDA.* The following table reconciles net income to Adjusted EBITDA for the three-month period ending September 30, 2011 and the three-month and twelve-month periods ending December 31, 2011.

	Guidance					
	3 Months Ending September 30, 2011		**3 Months Ending December 31, 2011**		**12 Months Ending December 31, 2011**	
	Low	**High**	**Low**	**High**	**Low**	**High**
	(in millions)					
Reconciliation to Adjusted EBITDA						
Net Income	$ 11.5	$ 16.2	$ 17.4	$ 20.1	$ 51.1	$ 58.5
Interest expense, net of amounts capitalized	2.2	1.9	2.4	2.1	6.9	6.3
Depreciation, depletion and amortization	9.2	8.8	9.2	8.8	33.8	33.0
Selected Items Impacting Comparability						
Equity compensation expense	1.1	1.1	1.0	1.0	4.8	4.8
Insurance deductible related to property damage incident					0.5	0.5
Acquisition-related expenses					4.1	4.1
Mark-to-market of open derivative positions					(0.1)	(0.1)
Adjusted EBITDA	$ 24.0	$ 28.0	$ 30.0	$ 32.0	$ 101.0	$ 107.0

Forward-Looking Statements and Associated Risks

All statements included in this report, other than statements of historical fact, are forward-looking statements, including, but not limited to, statements identified by the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and sta regarding our business strategy, plans and objectives of our management 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 are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- significantly 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 short term optimization revenues from transactions involving uncontracted or unutilized capacity at our facilities;
- the effects of competition;
- 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;
- the impact of operational 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, and cavern temperature variances;
- risks related to the 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;
- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;
- 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;
- 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;
- future developments and circumstances at the time distributions are declared; and
- other factors and uncertainties inherent in the development and operation of natural gas storage facilities.

We undertake no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in our filings with the Securities and Exchange Commission, which information is incorporated by reference herein.

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 hereunto duly authorized.

	PAA Natural Gas Storage, L.P.		
	By:	PNGS GP LLC, its general partner	
Date: August 3, 2011	By:	/s/ AL SWANSON	
		Name:	Al Swanson
		Title:	*Executive Vice President and Chief Financial Officer*