PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 05, 2009

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 5, 2009

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600, 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 5, 2009.

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

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its second-quarter 2009 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 detailed guidance for financial performance for third-and fourth-quarter calendar 2009, and updating our previous guidance for financial performance for the full calendar year of 2009 (which supersedes guidance pertaining to 2009 contained in our Form 8-K furnished on May 6, 2009). In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this 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 and Fourth Quarter 2009 Guidance; Update of Full Year 2009 Guidance

EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income and cash flows from operating activities are the most directly comparable GAAP measures to EBIT and EBITDA. In Note 10 below, we reconcile EBITDA and EBIT to net income for the 2009 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliation), which presents a historical reconciliation of certain commonly used non-GAAP financial measures, including EBIT and EBITDA. We present EBIT and EBITDA because we believe they provide 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 also believe that debt holders commonly use EBITDA to analyze partnership performance. In addition, we have highlighted the impact of our equity compensation plans, inventory valuation adjustments net of gains and losses from related derivative activities, gains and losses from other derivative activities, and foreign currency revaluations on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three months ending September 30 and December 31, 2009 and the twelve months ending December 31, 2009 is based on 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 covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as LPG sales) and acquisition synergies. 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 4, 2009. We undertake no obligation to publicly update or revise any forward-looking statements.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	Actual 6 Months Ended 6/30/2009	Guidance (1) 3 Months Ending September 30, 2009 Low	High	3 Months Ending December 31, 2009 Low	High	12 Months Ending December 31, 2009 Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 974	$ 418	$ 436	$ 444	$ 463	$ 1,836	$ 1,873
Field operating costs	(312)	(166)	(161)	(162)	(158)	(640)	(631)
General and administrative expenses	(100)	(49)	(47)	(48)	(46)	(197)	(193)
	562	203	228	234	259	999	1,049
Depreciation and amortization expense	(114)	(59)	(57)	(60)	(58)	(233)	(229)
Interest expense, net	(107)	(60)	(58)	(60)	(58)	(227)	(223)
Income tax benifit / (expense)	1	(2)	(2)	(2)	(2)	(3)	(3)
Other income (expense), net	5					5	5
Net Income	**$ 347**	**$ 82**	**$ 111**	**$ 112**	**$ 141**	**$ 541**	**$ 599**
Net Income to Limited Partners	$ 282	$ 47	$ 76	$ 76	$ 105	$ 405	$ 463
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	126	129	129	129	129	128	128
Net Income Per Unit	$ 2.20	$ 0.36	$ 0.58	$ 0.58	$ 0.80	$ 3.12	$ 3.57
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	127	130	130	130	130	129	129
Net Income Per Unit	$ 2.18	$ 0.36	$ 0.58	$ 0.58	$ 0.80	$ 3.10	$ 3.54
EBIT	**$ 453**	**$ 144**	**$ 171**	**$ 174**	**$ 201**	**$ 771**	**$ 825**
EBITDA	**$ 567**	**$ 203**	**$ 228**	**$ 234**	**$ 259**	**$ 1,004**	**$ 1,054**
Selected Items Impacting Comparability							
Equity compensation charge	$ (25)	$ (7)	$ (7)	$ (6)	$ (6)	$ (38)	$ (38)
Inventory valuation adjustments net of gains and losses from related derivative activities	32					32	32
Gains / (losses) from other derivative activities	36					36	36
Net gain on foreign currency revaluation	12					12	12
	$ 55	$ (7)	$ (7)	$ (6)	$ (6)	$ 42	$ 42
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 239	$ 124	$ 130	$ 127	$ 133	$ 490	$ 502
Facilities	102	51	55	54	58	207	215
Marketing	166	35	50	59	74	260	290
Other Income (Expense), net	5					5	5
Adjusted EBITDA	$ 512	$ 210	$ 235	$ 240	$ 265	$ 962	$ 1,012
Adjusted Net Income	$ 292	$ 89	$ 118	$ 118	$ 147	$ 499	$ 557
	$ 1.77	$ 0.41	$ 0.63	$ 0.62	$ 0.84	$ 2.80	$ 3.24

Adjusted Basic Net Income per Limited Partner Unit							
Adjusted Diluted Net Income per Limited Partner Unit	$ 1.75	$ 0.41	$ 0.63	$ 0.62	$ 0.83	$ 2.78	$ 3.22

(1) The projected average foreign exchange rate was based on actual rates for July 2009 and $1.15 CAD to $1 USD for the remainder of 2009. The rate as of August 4, 2009 was $1.07 CAD to $1 USD. A $0.10 change in the foreign exchange rate will impact forecasted EBITDA by approximately $6 million.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
FX	Foreign currency exchange
General partner (GP)	As the context requires, general partner refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.
Class B units	Class B units of Plains AAP, L.P.

2. *Business Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. The following is a brief explanation of the operating activities for each segment as well as key metrics.

a. *Transportation.* Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. We also include in this segment our equity earnings from our investment in the Butte and Frontier pipeline systems and Settoon Towing, in which we own non-controlling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. Segment profit is forecast using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level and mix of volumes transported or expenses incurred during the period.

The following table summarizes our total pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Actual		**2009 Guidance**	
	Six Months Ended June 30,	**Three Months Ending September 30,**	**Three Months Ending December 31,**	**Twelve Months Ending December 31,**
Average Daily Volumes (000 Bbls/d)				
All American	39	42	42	41

Basin	417	400	360	398
Capline	205	225	225	215
Line 63 / 2000	133	135	130	133
Salt Lake City Area Systems (1)	121	140	140	131
West Texas / New Mexico Area Systems (1)	384	370	370	377
Rainbow	188	180	185	185
Manito	63	65	65	64
Rangeland	56	55	50	54
Refined Products	94	100	100	97
Other	1,201	1,283	1,263	1,237
	2,901	2,995	2,930	2,932
Trucking	86	85	95	88
	2,987	3,080	3,025	3,020
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.44	$ 0.45(2)	$ 0.47(2)	$ 0.45(2)

(1) The aggregate of multiple systems in the respective areas.

(2) Mid-point of guidance.

b. *Facilities*. Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, LPG and natural gas, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. This segment also includes our equity earnings from our 50% investment in PAA/Vulcan Gas Storage, LLC, which owns and operates approximately 40 Bcf of underground natural gas storage capacity and is constructing an additional 10 Bcf of salt dome storage capacity at its Pine Prairie facility.

Segment profit is forecast using the volume assumptions in the table below, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

	Actual Six Months Ended June 30,	Three Months Ending September 30,	2009 Guidance Three Months Ending December 31,	Twelve Months Ending December 31,
Operating Data				
Crude oil, refined products and LPG storage (MMBbls/Mo.)	55	56	56	56
Natural Gas Storage (Bcf/Mo.)	18	20	20	19
LPG Processing (MBbl/d)	16	17	17	17
Facilities Activities Total (1)				
Avg. Capacity (MMBbls/Mo.)	59	60	60	60
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.29	$ 0.30(2)	$ 0.31(2)	$ 0.29(2)

(1) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to barrel of crude oil ratio; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

(2) Mid-point of guidance.

c. *Marketing*. Our marketing segment operations generally consist of the following merchant activities:

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of LPG;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

The level of profit in the marketing segment is influenced by overall market structure and the degree of volatility in the crude oil market as well as variable operating expenses. Forecasted operating results for the remainder of 2009 reflect the current market structure and seasonal, weather-related variations in LPG sales. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory, based on current and anticipated market conditions. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location, quality and contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual Six Months Ended June 30,	2009 Guidance Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering	627	615	610	620
LPG Sales	102	70	150	106
Refined Products	36	35	35	35
Waterborne foreign crude imported	57	45	60	55
	822	765	855	816
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 1.11	$ 0.60(1)	$ 0.85(1)	$ 0.92(1)

(1) Mid-point of guidance.

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, forecasted capital expenditures and projected in-service dates. Depreciation is computed using the straight-line method over estimated useful lives, which range from 3 years (for office furniture and equipment) to 40 years (for certain pipelines, crude oil terminals and facilities). Depreciation may vary during any one period due to gains and losses on intermittent sales of assets, asset retirement obligations, or asset impairments.

4. *Selected Items Impacting Comparability.* Our operating results are impacted by items that affect comparability between reporting periods, such as the equity compensation benefit or charge associated with our long-term incentive programs. In addition, our actual results will reflect certain mark-to-market items such as gains and losses related to derivative activities, gains and losses from unrealized foreign currency transactions, and inventory revaluation adjustments. Our adjusted results exclude these selected items impacting comparability until such time as the underlying and offsetting physical transaction settles. Although the economics of these transactions as a whole are embedded in our guidance presented here, our selected items impacting comparability do not reflect these items as there is no accurate way to forecast the timing and magnitude of their ultimate effect. The timing of when these items will impact our results is primarily dependent on the timing of the purchase or sale of the underlying inventory, which is dependent on market variables and other factors. The magnitude of these items depends on market prices and exchange rates at a point in time. Accordingly, our actual results could differ materially from our projections.

5. *Acquisitions and Other Capital Expenditures.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions to which we may commit after the date hereof. We forecast capital expenditures during calendar 2009 to be approximately $370 million for expansion projects with an additional $85 to $95 million for maintenance capital projects. During the first six months of 2009, we spent $158 million and $44 million, respectively, for expansion and maintenance capital projects. Following are some of the more notable projects and forecasted expenditures for the year:

	Calendar 2009 (in millions)
Expansion Capital	
• St. James Phase III (1)	$ 73
• Rangeland tankage and connections	35
• Kerrobert pumping project	34
• Patoka Phase II & III	30
• Cushing Phase VII	29
• Nipisi storage and truck terminal	20

• Salt Lake City pipeline		14
• Pier 400		13
• Paulsboro		12
• Other projects, including acquisition related expansion projects (2)		110
		370
Maintenance Capital		85 - 95
Total Projected Capital Expenditures (excluding acquisitions)	$	455 - 465

(1) Includes a dock and condensate tanks.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2008.

6. *Capital Structure.* This guidance is based on our capital structure as of June 30, 2009, as adjusted to give effect to the issuance on July 23, 2009 of $500 million of 3-year senior notes.

7. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, forecasted acquisitions and capital expenditures for maintenance and expansion projects, expected timing of collections and payments, and forecasted levels of inventory and other working capital sources and uses. Interest rate assumptions for variable rate debt are based on the current forward LIBOR curve.

Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, deferred amounts associated with terminated interest-rate hedges and interest on short-term debt for non-contango inventory (primarily hedged LPG inventory and New York Mercantile Exchange and IntercontinentalExchange margin deposits). Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for inventory stored in a contango market. We treat interest on contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

8. *Net Income per Unit.* Basic net income per limited partner unit is calculated by dividing net income allocated to limited partners by the basic weighted average units outstanding during the period.

	Actual 6 Months Ended 06/30/09	**Guidance (in millions, except per unit data)**					
		3 Months Ending September 30, 2009		**3 Months Ending December 31, 2009**		**12 Months Ending December 31, 2009**	
		Low	**High**	**Low**	**High**	**Low**	**High**
Numerator for basic and diluted earnings per limited partner unit:							
Net Income	$ 347	$ 82	$ 111	$ 112	$ 141	$ 541	$ 599
General partners incentive distribution (1)	(60)	(33)	(33)	(34)	(34)	(127)	(127)
	287	49	78	78	107	414	472
General partner 2% ownership (1)	(5)	(2)	(2)	(2)	(2)	(9)	(9)
Net income available to limited partners	282	47	76	76	105	405	463
Adjustment in accordance with EITF 07-04 (1)	(5)	(1)	(1)	(1)	(2)	(7)	(8)
Net income available to limited partners under EITF 07-04	$ 277	$ 46	$ 75	$ 75	$ 103	$ 398	$ 455
Denominator:							
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	126	129	129	129	129	128	128
Effect of dilutive securities:							
Weighted average LTIP units	1	1	1	1	1	1	1
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	127	130	130	130	130	129	129
Basic net income per limited partner unit	$ 2.20	$ 0.36	$ 0.58	$ 0.58	$ 0.80	$ 3.12	$ 3.57
	$ 2.18	$ 0.36	$ 0.58	$ 0.58	$ 0.80	$ 3.10	$ 3.54

Diluted net income per limited partner unit	

(1) We allocate net income to our general partner based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). EITF 07-04 requires 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. We reflect the impact of this difference as the Adjustment in accordance with EITF 07-04.

In conjunction with the Pacific and Rainbow acquisitions, the general partner reduced the amounts due it as incentive distributions by an aggregate amount of $75 million. Approximately $49 million of this reduction was realized as of June 30, 2009. Incentive distributions will be reduced by $10 million for the balance of 2009, $11 million in 2010 and $5 million in 2011.

The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Based on the current number of units outstanding, each $0.05 per unit annual increase or decrease in the distribution relative to forecasted amounts decreases or increases net income available for limited partners by approximately $7 million ($0.05 per unit) on an annualized basis.

9. *Equity Compensation Plans* . The majority of grants outstanding under our equity compensation plans (LTIP and Class B units) contain vesting criteria that are based on a combination of performance benchmarks and service period. The grants will vest in various percentages, typically on the later to occur of specified earliest vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of August 5, 2009, estimated vesting dates range from

May 2010 to January 2016 and annualized distribution levels range from $3.00 to $4.50. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012 and all others are forfeited.

On July 15, 2009, we declared an annualized distribution of $3.62 payable on August 14, 2009 to our unitholders of record as of August 4, 2009. We have made the assessment that a $3.75 distribution level is probable of occurring and accordingly, for grants that vest at annualized distribution levels of $3.75 or less, guidance includes an accrual over the applicable service period at an assumed market price of approximately $43.00 per unit as well as the fair value associated with awards that will vest on a date certain The actual amount of equity compensation expense amortization in any given period will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the date of actual vesting, (iii) the amount of the amortization in the early years, (iv) the probability assessment of achieving future distribution rates, and (v) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at September 30, 2009 would change the third-quarter equity compensation expense by approximately $5 million. Therefore, actual net income could differ materially from our projections.

10. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles EBITDA and EBIT to net income, for the three-month guidance range ending September 30, 2009 and three-month and twelve-month guidance ranges ending December 31, 2009.

Guidance (in millions)