PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 01, 2006

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 1, 2006

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 1, 2006

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 2006 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 the third and fourth quarter of calendar 2006 and modifying certain aspects of our previous guidance for financial performance for the full year of calendar 2006 (which supersedes guidance in our 8-K furnished on June 12, 2006). This guidance excludes any contribution from the proposed merger with Pacific Energy Partners, L.P. announced June 12, 2006. 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, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Third and Fourth Quarter 2006 Estimates; Update of Full Year 2006 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 11 below, we reconcile EBITDA and EBIT to net income for the 2006 guidance periods presented. However, it is impractical to reconcile EBIT and EBITDA to cash flows from operating activities for forecasted periods. 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 long-term incentive plan, the cumulative effect of a change in accounting principle and, to the extent known, gains and losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments) on EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three month periods ending September 30 and December 31 and twelve month period ending December 31, 2006 are based on assumptions and estimates that we believe are reasonable given our assessment of historical trends, business cycles and other information reasonably available. However, our assumptions and future performance are both subject to a wide range of business risks and uncertainties, so no assurance can be provided that actual performance will fall within the guidance ranges. Please refer to the 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 July 31, 2006. 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	Guidance*					
	Six Months Ended June 30, 2006	Three Months Ending September 30, 2006 Low	High	Three Months Ending December 31, 2006 Low	High	Twelve Months Ending December 31, 2006 Low	High
Pipeline							
Net revenues	$205.7	$105.8	$107.2	$106.0	$107.4	$417.5	$420.3
Field operating costs	(90.5)	(47.5)	(46.9)	(46.9)	(46.3)	(184.9)	(183.7)
General and administrative expenses	(24.1)	(11.4)	(11.2)	(11.6)	(11.4)	(47.1)	(46.7)
	91.1	46.9	49.1	47.5	49.7	185.5	189.9
Gathering, Marketing, Terminalling & Storage							
Net revenues	234.7	120.5	127.3	117.8	124.2	473.0	486.2
Field operating costs	(78.4)	(43.5)	(42.9)	(43.4)	(42.8)	(165.3)	(164.1)
General and administrative expenses	(35.1)	(18.8)	(18.5)	(19.0)	(18.7)	(72.9)	(72.3)
	121.2	58.2	65.9	55.4	62.7	234.8	249.8
Segment Profit	212.3	105.1	115.0	102.9	112.4	420.3	439.7
Depreciation and amortization expense	(42.9)	(24.8)	(24.4)	(25.8)	(25.4)	(93.5)	(92.7)
Interest expense	(33.3)	(20.4)	(19.6)	(20.4)	(19.6)	(74.1)	(72.5)
Equity earnings in PAA / Vulcan Gas Storage, LLC	0.9	0.9	1.0	3.5	4.0	5.3	5.9
Other Income (Expense)	0.4					0.4	0.4
Income Before Cumulative Effect of Change in Accounting Principle	**137.4**	**60.8**	**72.0**	**60.2**	**71.4**	**258.4**	**280.8**
Cumulative Effect of Change in Accounting Principle	6.3					6.3	6.3
Net Income	**$143.7**	**$ 60.8**	**$72.0**	**$60.2**	**$71.4**	**$264.7**	**$287.1**
Net Income to Limited Partners	$128.2	$ 50.7	$61.6	$50.1	$61.1	$229.0	$250.9
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	75.5	80.0	80.0	81.0	81.0	78.0	78.0
Net Income Per Unit**	$1.55	$ 0.63	$0.75	$0.62	$0.73	$ 2.89	$ 3.03
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	76.3	80.9	80.9	82.1	82.1	78.9	78.9
Net Income Per Unit**	$1.53	$ 0.63	$0.74	$0.61	$0.73	$ 2.86	$ 3.00
EBIT	**$177.0**	**$ 81.2**	**$91.6**	**$80.6**	**$91.0**	**$338.8**	**$359.6**
EBITDA	**$219.9**	**$106.0**	**$116.0**	**$106.4**	**$116.4**	**$432.3**	**$452.3**
Selected Items Impacting Comparability							
LTIP charge	$(16.8)	$ (9.0)	$(9.0)	$(8.6)	$(8.6)	$(34.4)	$(34.4)
Cumulative Effect of Change in Accounting Principle	6.3					6.3	6.3
SFAS 133 Mark-to-Market Adjustment	(3.1)					(3.1)	(3.1)
	$(13.6)	$ (9.0)	$(9.0)	$(8.6)	$(8.6)	$(31.2)	$(31.2)
Excluding Selected Items Impacting Comparability							
Adjusted EBITDA	$233.5	$115.0	$125.0	$115.0	$125.0	$463.5	$483.5
Adjusted Net Income	$157.3	$ 69.8	$81.0	$68.8	$80.0	$295.9	$318.3
Adjusted Basic Net Income per Limited Partner Unit	$1.87	$ 0.74	$0.88	$0.72	$0.86	$ 3.33	$ 3.61
Adjusted Diluted Net Income per Limited Partner Unit	$1.85	$ 0.74	$0.87	$0.71	$0.85	$ 3.29	$ 3.57

* The projected average foreign exchange rate is $1.15 CAD to $1 USD.

** See Note 9. The application of EITF 03-06 may result in interim period amounts not totaling to the annual amount.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Bbl/d	Barrel per day
Segment Profit	Net revenues less purchases, field operating costs, and segment general and administrative expenses
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other petroleum products
FX	Foreign currency exchange
GMT&S	Gathering, Marketing, Terminalling & Storage

2. *Pipeline Operations.* Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, production declines and other external factors beyond our control. Actual segment profit could vary materially depending on the level of volumes transported.

For the three month periods ending September 30 and December 31, 2006 projected volumes incorporate assumptions with respect to 1) additional throughput agreements on the Basin and Capline Pipeline Systems, 2) acquisitions of certain assets from BP and Chevron, and 3) higher Canadian volumes primarily due to the purchase of the remaining interest in Cactus Lake Pipeline. Volumes are impacted by a combination of anticipated seasonal demand, acquisitions, recovery of certain volumes impacted by last year s hurricanes, and natural production declines.

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

	Calendar 2006			
	Actual	**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's Bbl/d)				
All American	48	51	46	48
Basin	322	340	315	324
Capline	132	180	180	156
Cushing to Broome	75	80	79	77
North Dakota/Trenton	85	90	95	89
West Texas / New Mexico area systems(1)	460	397	396	428
Canada	246	262	265	256
Other(3)(4)	540	757	783	654
	1,908	2,157	2,159	2,032
Segment Profit $/Bbl				
As Reported/Guidance	$0.264	$0.242 (2)	$0.245 (2)	$0.253 (2)
Excluding Selected Items Impacting Comparability	$0.285	$0.262 (2)	$0.265 (2)	$0.274 (2)

(1) The aggregate of multiple systems in the West Texas / New Mexico area.

(2) Mid-point of guidance.

(3) Includes approximately 150,000 Bbl/d and 35,000 Bbl/d related to assets purchased from BP effective July 1, 2006 and July 31, 2006, respectively.

(4) Includes approximately 40,000 Bbl/d related to assets we have agreed to purchase from Chevron Pipe Line Company with an estimated effective date of August 31, 2006.

Segment profit is forecast using the volume assumptions in the table above, priced at tariff rates currently received, with adjustments where appropriate for estimated escalation in certain rates as allowed by contractual terms, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Effective July 1, 2006, common carrier tariffs are permitted to escalate approximately 6.15% in accordance with FERC regulated guidelines. However, in certain instances, contractual arrangements or market forces may not allow us to realize the benefit of these permitted increases.

To illustrate the impact volume changes may have on segment profit, the following table provides a volume sensitivity analysis of three systems representing approximately 27% of total pipeline net revenues.

Volume Sensitivity Analysis

System	**Incr (Decr) in Volume (Bbls/d)**	**% of System Total**		**Incr (Decr) in Annualized Segment Profit (in millions)**
All American	5,000	10	%	$3.6
Basin	20,000	6	%	1.4
Capline	10,000	6	%	1.3

3. *Gathering, Marketing, Terminalling and Storage Operations*. The level of profit in the GMT&S segment is influenced by overall market structure and the degree of volatility in the crude oil market as well as variable operating expenses. Operating results for the three month periods ending September 30 and December 31, 2006 reflect an expected continuation of the current contango market and favorable market conditions generally consistent with the conditions experienced over most of 2005 and 2006 to date, although not quite as favorable as market conditions in the first six months of 2006. These market conditions are considered favorable relative to our asset base and business model. Unexpected changes in market structure or volatility (or lack thereof) could cause actual results to differ materially from forecasted results.

	Calendar 2006 Actual Six Months Ended June 30	**Guidance(1) Three Months Ending September 30**	**Three Months Ending December 31**	**Twelve Months Ending December 31**
Average Daily Volumes (000 s Bbl/d)				
Crude Oil Lease Gathering	637	675	673	656
LPG	66	50	93	68
Waterborne Foreign Crude Imported	50	50	50	50
	753	775	816	774
Segment Profit $/Bbl				
As Reported/Guidance	$0.89	$0.87 (1)	$0.79 (1)	$0.86 (1)
Excluding Selected Items Impacting Comparability	$0.98	$0.94 (1)	$0.85 (1)	$0.94 (1)

(1) Mid-point of guidance.

Segment profit is forecast using the volume assumptions stated above and estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory based on current and anticipated market conditions. The forecast also includes the incremental profits from recently completed acquisitions. 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. Based on our mid-point projection of adjusted segment profit per barrel for calendar 2006, a 15,000 Bbl/d variance in lease gathering volumes would impact segment profit by approximately $5.1 million on an annualized basis. A $0.01 variance in the aggregate average per-barrel margin would impact segment profit by approximately $2.8 million on an annualized basis.

4. *Depreciation and Amortization.* Depreciation and amortization are forecast based on our existing depreciable assets and forecasted capital expenditures. Depreciation is computed using the straight-line method over estimated useful lives, which range from 3 years (for office property and equipment) to 40 years (for certain pipelines, crude oil terminals and facilities).

5. *Statement of Financial Accounting Standards No. 133 Accounting for Derivative Instruments and Hedging Activities (SFAS 133).* The guidance presented above does not include assumptions or projections with respect to potential gains or losses related to derivatives accounted for under SFAS 133, as there is no accurate way to forecast these potential gains or losses. The potential gains or losses related to these derivatives (primarily mark-to-market adjustments) could cause actual net income to differ materially from our projections.

6. *Acquisitions and Capital Expenditures.* As indicated in Note 2 (Pipeline Operations), this guidance includes assets we have agreed to purchase pursuant to definitive agreements with Chevron Pipe Line Company based on an estimated closing date of August 2006. Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any assumptions or forecasts for any other acquisition that may be made after the date hereof except for the pending acquisition. Capital expenditures for expansion projects are forecast to be approximately $275 million during calendar 2006 of which $104 million was incurred in the first six months of 2006. Following are some of the more notable projects to be undertaken in 2006 and the estimated expenditures for the year.

	Calendar 2006 (in millions)
Expansion Capital	
• St. James, Louisiana storage facility	$ 65
• Kerrobert tankage	32
• Spraberry System expansion	19
• East Texas/Louisiana tankage	17
• High Prairie rail terminals	13
• Midale/Regina truck terminal	13
• Wichita Falls tankage	10
• Truck trailers	9
• Basin connection Oklahoma	9
• Mobile/ Ten Mile tankage and metering	8
• Other Projects	80
	275
Maintenance Capital	20
Total Projected Capital Expenditures (excluding acquisitions)	$295

7. *Capital Structure.* This guidance is based on our capital structure as of June 30, 2006 as adjusted to give effect to the sale in the third quarter of 3.7 million common units and the use of the proceeds of such sale to fund acquisitions, repay indebtedness under credit facilities and for general partnership

purposes. The Partnership s policy is to finance acquisitions and major growth capital projects with at least 50% equity or cash flow in excess of distributions.

8. *Interest Expense.* Debt balances are projected based on estimated cash flows, current distribution rates, forecasted 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 expense for the six months ending December 31, 2006 is expected to be between $39.2 million and $40.8 million, assuming an average long-term debt balance of approximately $1.3 billion during the period and an all-in average rate of approximately 6.2%. Included in the effective cost of debt are projected interest payments, as well as commitment fees, amortization of long-term debt discounts, 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 International Petroleum Exchange margin deposits). At June 30, 2006, 96% of our long-term debt balance was fixed at an average interest rate of 6.1%. The amortization of deferred amounts associated with terminated interest rate hedges results in a non-cash component to interest expense of approximately $400,000 per quarter through September 2006, decreasing to approximately $100,000 per quarter thereafter until fully amortized over the next ten years. Interest expense does not include interest on borrowings for contango inventory. We treat those costs as carrying costs of crude oil and include it as part of the purchase price of crude oil.

9. *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. Under *Emerging Issues Task Force Issue 03-06: Participating Securities and the Two-Class Method under FASB Statement No. 128* (EITF 03-06), when the Partnership s aggregate net income exceeds the aggregate distribution made during such period, earnings per limited partner unit are calculated as if all of the earnings for the period were distributed, regardless of the pro forma nature of the allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. Although EITF 03-06 does not impact overall net income or other financial results of the Partnership, for periods in which aggregate net income exceeds the aggregate distributions for such period, earnings per limited partner unit will be reduced. The following table sets forth the computation of basic and diluted earnings per limited partner unit.

	Guidance (in millions, except per unit data)					
	Three Months Ending September 30, 2006		**Three Months Ending December 31, 2006**		**Twelve Months Ending December 31, 2006**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Numerator for basic and diluted earnings per limited partner unit:						
Net Income	$60.8	$72.0	$60.2	$71.4	$264.7	$287.1
Less:						
General partner s incentive distribution	(9.1)	(9.1)	(9.1)	(9.1)	(31.1)	(31.1)
	51.7	62.9	51.1	62.3	233.6	256.0
General partner 2% ownership	(1.0)	(1.3)	(1.0)	(1.2)	(4.6)	(5.1)
Net income available to limited partners	50.7	61.6	50.1	61.1	229.0	250.9
Pro forma additional general partner s distribution		(1.5)		(1.2)	(3.3)	(14.3)
Net Income available for limited partners under EITF 03-06	$50.7	$60.1	$50.1	$59.9	$225.7	$236.6
Denominator:						
Denominator for basic earnings per limited partner unit- weighted average number of limited partner units	80.0	80.0	81.0	81.0	78.0	78.0
Effect of dilutive securities:						
Weighted average LTIP units	0.9	0.9	1.1	1.1	0.9	0.9
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	80.9					