PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
February 24, 2005

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) **February 24, 2005**

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

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its fourth quarter and annual 2004 results. The Partnership is furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. The Partnership is also furnishing pursuant to Item 7.01 its projections of certain operating and financial results for the first quarter of 2005 and modifying certain aspects of our preliminary guidance for financial performance for the full year of calendar 2005. 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 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.

Item 9.01. Financial Statements and Exhibits

(c) Exhibit 99.1 Press Release dated February 24, 2005

Disclosure of First Quarter 2005 Estimates; Update of Full Year 2005 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 for EBIT and EBITDA. In Note 11 below, we reconcile EBITDA and EBIT to net income for the periods presented. We also 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 on EBITDA, Net Income and Net Income per Limited Partner Unit of our long-term incentive program and potential future revaluations of foreign currency.

The following guidance for the three months ending March 31, 2005 and twelve months ending December 31, 2005 is based on assumptions and estimates that we believe are reasonable given our assessment of historical trends, business cycles and currently available information. However, our assumptions and future performance are both subject to a wide range of business risks and uncertainties and also include projections for several recent acquisitions, 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 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 February 23, 2005. 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)

	Guidance(1) Three Months Ended March 31, 2005		Twelve Months Ended December 31, 2005	
	Low	**High**	**Low**	**High**
Pipeline				
Net revenues	$ 87.5	$ 89.5	$ 359.8	$ 365.3
Field operating costs	(34.5)	(33.5)	(140.7)	(138.8)
General and administrative expenses	(11.4)	(11.1)	(42.5)	(41.6)
	41.6	44.9	176.6	184.9
Gathering, Marketing, Terminalling & Storage				
Net revenues	61.1	64.4	240.3	246.1
Field operating costs	(28.9)	(28.3)	(110.1)	(108.6)
General and administrative expenses	(10.3)	(10.0)	(37.3)	(36.4)
	21.9	26.1	92.9	101.1
Segment Profit	63.5	71.0	269.5	286.0
Depreciation and amortization expense	(18.3)	(17.8)	(76.0)	(74.0)
Interest expense	(14.3)	(13.9)	(61.0)	(60.0)
Other Income (Expense) / LTIP	(2.8)	(2.8)	(10.4)	(10.4)
Net Income	**$ 28.1**	**$ 36.5**	**$ 122.1**	**$ 141.6**
Net Income to Limited Partners	$ 24.7	$ 32.9	$ 108.1	$ 127.2
Basic:				
Average Units Outstanding	67.3	67.3	67.3	67.3
Net Income Per Limited Partner Unit	$ 0.37	$ 0.49	$ 1.61	$ 1.89
Diluted:				
Average Units Outstanding	68.0	68.0	68.5	68.5
Net Income Per Limited Partner Unit	$ 0.36	$ 0.48	$ 1.58	$ 1.86
EBIT	**$ 42.4**	**$ 50.4**	**$ 183.1**	**$ 201.6**
EBITDA	**$ 60.7**	**$ 68.2**	**$ 259.1**	**$ 275.6**
Selected Items Impacting Comparability				
Non-cash LTIP charge	$ (2.8)	$ (2.8)	$ (10.4)	$ (10.4)
Non-cash FX Gain (Loss)	(2.5)	(2.0)	(2.5)	(2.0)
	$ (5.3)	$ (4.8)	$ (12.9)	$ (12.4)
Excluding Selected Items Impacting Comparability				
EBITDA	$ 66.0	$ 73.0	$ 272.0	$ 288.0
Net Income	$ 33.4	$ 41.3	$ 135.0	$ 154.0
Basic Net Income per Limited Partner Unit	$ 0.44	$ 0.56	$ 1.79	$ 2.07
Diluted Net Income per Limited Partner Unit	$ 0.44	$ 0.55	$ 1.76	$ 2.03

(1) The projected foreign exchange rate is $1.30 CAD to $1 USD.

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Notes and Significant Assumptions:

1. *Definitions*.

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Bbl/d	Barrels 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

2. *Pipeline Operations.* Pipeline volume estimates are based on historical and anticipated future operating performance. Actual segment earnings could vary materially depending on the level of volumes transported. The following table summarizes our pipeline volumes and breaks out the major systems that are significant either in total volumes transported or in contribution to total net revenue.

	2005 Guidance Three Months Ended March 31	**Twelve Months Ended December 31**
Average Daily Volumes (000 s Bbl/d)		
All American	54	54
Basin	260	270
Capline	140	140
Cushing to Broom	25	65
West Texas / New Mexico area systems(1)	395	385
Other	501	546
	1,375	1,460
Canadian Pipelines(2)	265	265
	1,640	1,725

(1) The aggregate of 10 systems in the West Texas / New Mexico area.

(2) The aggregate of 7 systems.

Average volumes for the first quarter are expected to be in the range of 1,640,000 Bbl/d, compared to an average 1,725,000 Bbl/d for the year. The volume growth during the year is driven primarily by the start-up of the Cushing to Broom pipeline system in March, which is expected to exit the year at 80,000 Bbl/d.

Net revenues were forecasted using the above volume assumptions priced at tariff rates currently received, with adjustments where appropriate for estimated escalation rates as allowed by contractual terms. To illustrate the impact volume changes may have on segment profit, the following table provides a volume sensitivity analysis of three systems representing approximately 31% of total pipeline net revenues.

System	Volume Sensitivity Analysis Increase / (Decrease) in Volume (Bbls/d)	% of System Total	Increase / (Decrease) in Annualized Segment Profit (in millions)
All American	5,000	9 %	$ 3.2
Basin	20,000	7 %	1.8
Capline	10,000	7 %	1.5

Pipeline operating expenses in the first quarter and for the year will be impacted by a crude oil release that occurred in early January 2005 as a result of an overflow from a temporary storage tank located in East Texas. Estimated costs for emergency response, site remediation and regulatory fines are expected to be approximately $1.4 million.

3. *Gathering, Marketing, Terminalling and Storage Operations*. Our guidance is predicated on continued price volatility in the crude oil market, albeit less volatility than what was experienced in 2004. Volumes from crude oil lease gathering are projected to average 630,000 Bbl/d in the first quarter and increase to an average 640,000 Bbl/d for the year. LPG volumes are influenced by seasonal demands with volumes greater during the winter months than the remainder of the year; therefore, first quarter volumes are expected to average 70,000 Bbl/d versus the annual average of 50,000 Bbl/d.

	2005 Guidance Three Months Ended March 31	Twelve Months Ended December 31
Average Daily Volumes (000 s Bbl/d)		
Crude Oil Lease Gathering	630	640
LPG	70	50
	700	690

Segment profit is forecast using the volume assumptions stated above and estimates of unit margins, operating expenses and G&A based on current and anticipated market conditions. 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 projected segment profit per barrel for the first quarter of 2005, a 15,000 Bbl/d variance in lease gathering volumes would impact segment profit by an approximate $3.0 million on an annualized basis. A $0.01 variance in the aggregate average per-barrel margin would impact segment profit by an approximate $2.6 million on an annualized basis.

4. *Depreciation & Amortization.* Depreciation and amortization is forecast based on our existing depreciable assets and forecast 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 50 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 forecast presented above does not include assumptions or projections with respect to potential gains or losses related to SFAS 133, as there is no accurate

way to forecast these potential gains or losses. The potential gains or losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments) could cause actual net income to differ materially from our projections.

6. *Acquisitions, Capital Expenditures and Linefill Additions.* 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 material acquisition that may be made after the date hereof. Capital expenditures for expansion projects are forecast to be approximately $100 million during calendar 2005, of which approximately 90% will be spent in the first nine months of the year. Some of the more notable projects are:

- Capital projects associated with the Link acquisition $18 million,
- Trenton pipeline expansion $16 million,
- Cushing Phase V expansion $13 million,
- Cal Ven fractionator $16 million, and
- Shell South Louisiana Asset Acquisition $8.0 million

Capital expenditures for maintenance projects are forecast to be approximately $19 million during 2005. Linefill requirements in 2005 are expected to increase approximately 500,000 barrels and will be purchased at market prices.

7. *Capital Structure.* No changes to the capital structure in 2005 are anticipated except for the issuance of approximately 50,000 units to satisfy equity grants issued under the 1998 LTIP plan deemed probable to vest during 2005.

8. *Interest Expense.* Debt balances are projected based on estimated cash flows, current distribution rates, capital expenditures for maintenance and expansion projects, linefill purchases, planned sales of surplus equipment, expected timing of collections and payments, and forecast levels of inventory and other working capital sources and uses.

Calendar 2005 interest expense is expected to be between $60.0 million and $61.0 million assuming an average long-term debt balance of approximately $1.0 billion and an all-in average rate of approximately 6.1%. While interest on floating rate debt is based on a forward one year LIBOR index curve of 3.2%, approximately 80% of our projected average debt balance has an average fixed interest rate of 6.0%. Included in the effective cost of debt are not only current cash payments, but also commitment fees, amortization of long-term debt discounts, and deferred amounts associated with terminated interest rate hedges. The amortization of deferred amounts associated with terminated interest rate hedges results in a non-cash component to interest expense of approximately $1.6 million per year (approximately $400,000 per quarter). Approximately 73% of this amount will be completely amortized by the fourth quarter of 2006. The remainder will be amortized over the next nine years.

9. *Net Income per Unit.* Basic net income per limited partner unit is calculated by dividing the net income allocated to limited partners by the basic weighted average units outstanding during the period. Basic weighted average units outstanding are projected to average approximately 67.3 million units for 2005.

Net income allocated to limited partners is impacted by the income allocated to the general partner and the amount of the incentive distribution paid to the general partner. Accordingly, for each $0.05 per unit annual increase in the distribution rate, net income available for limited partners decreases approximately $1.0 million ($0.02 per unit) on an annualized basis. The amount of income allocated to our limited partner interests is 98% of the total partnership

income after deducting the amount of the general partner s incentive distribution. Based on our current annualized distribution rate of $2.45 per unit, our general partner s distribution is forecast to be approximately $15.2 million annually, of which $11.8 million is attributed to the incentive distribution rights. The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units.

10. *Long-term Incentive Plans*. The majority of phantom unit grants outstanding under our 1998 and 2005 Long-Term Incentive Plans contain vesting criteria that are based on a combination of performance benchmarks and service period. The phantom units generally vest on the later of 2 years, 4 years or 5 years and achievement of annualized distribution levels of $2.60, $2.80 and $3.00 per unit, respectively, and the majority of the phantom units have a final service period vesting in 2011. Accordingly, for phantom units that have a final service period vesting in 2011, guidance includes the pro rata accrual associated with a six-year service period. For 2005, the guidance includes approximately $10.1 million of non-cash expense associated with these phantom units. The actual amount of LTIP expense amortization in any given year will be directly influenced by fluctuations in our unit price and the amount of amortization in the early years will also be increased if a determination is made that achievement of any of the performance thresholds is probable.

11. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the guidance ranges for EBIT and EBITDA to net income.

	Guidance Three Months Ended March 31, 2005		**Twelve Months Ended December 31, 2005**	
	Low	**High**	**Low**	**High**
	(in millions)			
Reconciliation to Net Income				
EBITDA	$ 60.7	$ 68.2	$ 259.1	$ 275.6
Depreciation and amortization	18.3	17.8	76.0	74.0
EBIT	42.4	50.4	183.1	201.6
Interest expense	14.3	13.9	61.0	60.0
Net Income	$ 28.1	$ 36.5	$ 122.1	$ 141.6

Forward-Looking Statements and Associated Risks

All statements, other than statements of historical fact, included in this report are forward-looking statements, including, but not limited to, statements identified by the words anticipate, believe, estimate, expect, plan, intend and forecast and similar expressions and statemen regarding our business strategy, plans and objectives of our management for future operations. 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:

- abrupt or severe production declines or production interruptions in outer continental shelf production located offshore California and transported on our pipeline system;
- the success of our risk management activities;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses;

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- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- maintenance of our credit rating and ability to receive open credit from our suppliers;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- successful third party drilling efforts in areas in which we operate pipelines or gather crude oil;
- demand for various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the effects of competition;
- continued creditworthiness of, and performance by, counter parties;
- the impact of crude oil price fluctuations;
- the impact of current and future laws, rulings and governmental regulations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- the currency exchange rate of the Canadian dollar;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our LTIP plan; and
- general economic, market or business conditions.

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.

	PLAINS ALL AMERICAN PIPELINE, L.P.		
	By:	PLAINS AAP, L. P., its general partner	
	By:	PLAINS ALL AMERICAN GP LLC, its general partner	
Date: February 24, 2005	By:	/s/ PHIL KRAMER	
		Name:	Phil Kramer
		Title:	*Executive Vice President and Chief Financial Officer*

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