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)—**June 12, 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 7.01. Regulation FD Disclosure

Plains All American Pipeline, L.P. (the "Partnership'') is furnishing this report pursuant to Item 7.01 of Form 8-K to provide updated guidance for financial performance for the second half of 2006 and to establish initial, preliminary guidance for financial performance for 2007. This guidance excludes any contribution from the proposed merger with Pacific Energy Partners, L.P. announced concurrently with the furnishing of this Form 8-K. The second quarter of 2006 information included in this 8-K supplements the updated guidance information contained in our press release dated May 25, 2006. The information in this 8-K for the second half of 2006 supersedes the guidance information contained in our 8-K dated May 3, 2006. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under 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.

Update of Second Half 2006 Estimates, Disclosure of Full Year 2007 Preliminary 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 also encourage you to visit our website at *www.paalp.com*, and 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, revaluations of foreign currency, 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 Limited Partner Unit.

The following guidance for the three months ending June 30, 2006 and the six months and twelve months ending December 31, 2006 as well as the preliminary guidance for calendar 2007 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 June 9, 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[(1)]					
	Three Months Ended March 31, 2006	Three Months Ending June 30, 2006		Six Months Ending December 31, 2006		Twelve Months Ending December 31, 2006	
		Low	High	Low	High	Low	High
Pipeline							
Net revenues	$ 96.4	$ 104.4	$ 106.6	$ 215.7	$ 218.5	$ 416.5	$ 421.5
Field operating costs	(45.1)	(48.2)	(47.6)	(95.6)	(94.4)	(188.9)	(187.1)
General and administrative expenses	(13.3)	(11.2)	(11.0)	(23.4)	(23.0)	(47.9)	(47.3)
	38.0	45.0	48.0	96.7	101.1	179.7	187.1
Gathering, Marketing, Terminalling & Storage							
Net revenues	111.6	119.0	124.9	236.1	249.7	466.7	486.2
Field operating costs	(37.2)	(39.1)	(38.5)	(83.4)	(82.2)	(159.7)	(157.9)
General and administrative expenses	(18.5)	(18.8)	(18.5)	(38.7)	(38.1)	(76.0)	(75.1)
	55.9	61.1	67.9	114.0	129.4	231.0	253.2
Segment Profit	93.9	106.1	115.9	210.7	230.5	410.7	440.3
Depreciation and amortization expense	(21.6)	(23.1)	(22.7)	(48.0)	(47.2)	(92.7)	(91.5)
Interest expense	(15.3)	(18.6)	(17.8)	(40.3)	(38.7)	(74.2)	(71.8)
Equity earnings (Loss) in PAA / Vulcan Gas Storage, LLC	(0.2)	0.6	0.8	1.9	2.1	2.3	2.7
Other Income (Expense)	0.3	—	—	—	—	0.3	0.3
Income Before Cumulative Effect of Change in Accounting Principle	**57.1**	**65.0**	**76.2**	**124.3**	**146.7**	**246.4**	**280.0**
Cumulative Effect of Change in Accounting Principle	6.3	—	—	—	—	6.3	6.3
Net Income	**$ 63.4**	**$ 65.0**	**$ 76.2**	**$ 124.3**	**$ 146.7**	**$ 252.7**	**$ 286.3**
Net Income to Limited Partners	$ 56.7	$ 56.5	$ 67.5	$ 107.4	$ 129.3	$ 220.6	$ 253.5
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	74.0	77.0	77.0	77.3	77.3	76.4	76.4
Net Income Per Unit	$ 0.73	$ 0.72	$ 0.79	$ 1.39	$ 1.54	$ 2.85	$ 3.06
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	75.7	78.7	78.7	79.0	79.0	78.1	78.1
Net Income Per Unit	$ 0.71	$ 0.71	$ 0.78	$ 1.36	$ 1.51	$ 2.79	$ 3.00
EBIT	**$ 78.7**	**$ 83.6**	**$ 94.0**	**$ 164.6**	**$ 185.4**	**$ 326.9**	**$ 358.1**
EBITDA	**$ 100.3**	**$ 106.7**	**$ 116.7**	**$ 212.6**	**$ 232.6**	**$ 419.6**	**$ 449.6**

Selected Items Impacting Comparability							
LTIP charge	$ (10.6)	$ (8.3)	$ (8.3)	$ (17.4)	$ (17.4)	$ (36.3)	$ (36.3)
Cumulative Effect of Change in Accounting Principle	6.3	—	—	—	—	6.3	6.3
SFAS 133 Mark-to-Market Adjustment	(0.7)	—	—	—	—	(0.7)	(0.7)
Gain (loss) on Foreign Currency Revaluation	(0.9)	—	—	—	—	(0.9)	(0.9)
	$ (5.9)	$ (8.3)	$ (8.3)	$ (17.4)	$ (17.4)	$ (31.6)	$ (31.6)

Excluding Selected Items Impacting Comparability							
Adjusted EBITDA	$ 106.2	$ 115.0	$ 125.0	$ 230.0	$ 250.0	$ 451.2	$ 481.2
Adjusted Net Income	$ 69.3	$ 73.3	$ 84.5	$ 141.7	$ 164.1	$ 284.3	$ 317.9
Adjusted Basic Net Income per Limited Partner Unit	$ 0.84	$ 0.84	$ 0.98	$ 1.61	$ 1.89	$ 3.29	$ 3.72
Adjusted Diluted Net Income per Limited Partner Unit	$ 0.82	$ 0.82	$ 0.96	$ 1.58	$ 1.85	$ 3.22	$ 3.64

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

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 end-user refineries, field declines and other external factors beyond our control. Actual segment profit could vary materially depending on the level of volumes transported.

For the three months ending June 30, 2006 projected volumes incorporate assumptions with respect to 1) additional throughput agreements and expected higher seasonal demand volumes on Capline Pipeline, and 2) higher Canadian volumes primarily due to the purchase of the remaining interest in Cactus Lake Pipeline. Volumes for the remainder of the year are impacted by a combination of anticipated seasonal demand, acquisitions, recovery of certain volumes impacted by last year's hurricanes, and natural field 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[3]		
	Three Months Ended March 31	Three Months Ending June 30	Six Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (000's Bbl/d)				
All American	44	50	48	47
Basin	314	297	266	285
Capline	86	176	160	146
Cushing to Broome	70	80	80	77
North Dakota/Trenton	82	89	91	89
West Texas / New Mexico area systems[1]	442	434	418	428
Canada[2]	239	261	264	258
Other[4]	537	528	663	600
	1,814	1,915	1,990	1,930
Average Segment Profit ($/Bbl)				
As Reported/Estimated	$ 0.233	$ 0.267[3]	$ 0.270[3]	$ 0.261[3]
Excluding Selected Items Impacting Comparability	$ 0.263	$ 0.289[3]	$ 0.292[3]	$ 0.283[3]

(1) The aggregate of 11 systems in the West Texas / New Mexico area.
(2) The aggregate of 8 systems.
(3) Mid-point of estimate.
(4) Includes approximately 150,000 Bbl/d from the assets not subject to a right of first refusal that we have agreed to purchase from BP with an estimated effective date of July 1, 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. To illustrate the impact volume changes may have on segment profit, the following table provides a volume sensitivity analysis of three systems representing approximately 25% 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	11%	$ 3.6
Basin	20,000	7%	1.4
Capline	10,000	7%	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 months ending June 30, 2006 and the second half of 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. These market conditions are considered very 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	Guidance[1]		
	Three Months Ended March 31	Three Months Ending June 30	Six Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (000's Bbl/d)				
Crude Oil Lease Gathering	615	635	651	638
LPG	84	50	93	80
	699	685	744	718
Segment Profit per Barrel				
As Reported/Estimated	$ 0.89	$ 1.04[1]	$ 0.89[1]	$ 0.92[1]
Excluding Selected Items Impacting Comparability	$ 1.01	$ 1.11[1]	$ 0.96[1]	$ 1.01[1]

(1) Mid-point of estimate.

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 $5.6 million on an annualized basis. A $0.01 variance in the aggregate average per-barrel margin would impact segment profit by approximately $2.6 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. *Foreign Currency Revaluations and 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 foreign currency revaluations and 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 foreign currency revaluations and 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 not subject to a right of first refusal that we have agreed to purchase pursuant to definitive agreements with BP based on an estimated closing date of July 1, 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 material acquisitions that may be made after the date hereof except for the pending acquisition. Capital expenditures for expansion projects are forecast to be approximately $250 million during calendar 2006 of which $45 million was incurred in the first quarter. 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	$ 60
· Kerrobert tankage and pumps	45
· Spraberry System expansion	20
· High Prairie truck and rail terminals	18
· East Texas/Louisiana tankage	16
· Wichita Falls tankage	11
· Midale/Regina truck terminal	11
· Truck trailers	11
· Other Projects	58
	250
Maintenance Capital	23
Total Projected Capital Expenditures (excluding acquisitions)	$ 273

7. *Capital Structure.* This guidance is based on our capital structure as of March 31, 2006, as adjusted to give effect to the sale in April 2006 of 1.2 million common units, the sale in May 2006 of $250 million of 30-year notes bearing a fixed rate of interest of 6.7% and the use of such proceeds to finance acquisitions completed in the second quarter of 2006. The Partnership intends to adhere to its policy of financing acquisitions and major growth capital projects with at least 50% equity or cash flow in excess of distributions; therefore, prospective changes in the capital structure will be made accordingly to comply with this policy.

8. *Interest Expense.* Debt balances are projected based on estimated cash flows, current distribution rates, 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.

   Calendar 2006 interest expense is expected to be between $71.8 million and $74.2 million, assuming an average long-term debt balance of approximately $1.2 billion and an all-in average rate of approximately 6.1%. 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 margin deposits). At March 31, 2006, 100% of our long-term debt balance was fixed at an average interest rate of 6.0%. 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 these 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)					
	Three Months Ending June 30, 2006		Six 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	$ 65.0	$ 76.2	$ 124.3	$ 146.7	$ 252.7	$ 286.3
Less:						
General partner's incentive distribution	(7.3)	(7.3)	(14.7)	(14.7)	(27.6)	(27.6)
	57.7	68.9	109.6	132.0	225.1	258.7
General partner 2% ownership	(1.2)	(1.4)	(2.2)	(2.7)	(4.5)	(5.2)
Net income available to limited partners	56.5	67.5	107.4	129.3	220.6	253.5
Pro forma additional general partner's incentive distribution	(1.0)	(6.5)	—	(10.0)	(2.9)	(19.4)
Net Income available for limited partners under EITF 03-06	$ 55.5	$ 61.0	$ 107.4	$ 119.3	$ 217.7	$ 234.1
Denominator:						
Denominator for basic earnings per limited partner unit- weighted average number of limited partner units	77.0	77.0	77.3	77.3	76.4	76.4
Effect of dilutive securities:						
Weighted average LTIP units	1.7	1.7	1.7	1.7	1.7	1.7
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	78.7	78.7	79.0	79.0	78.1	78.1
Basic net income per limited partner unit	$ 0.72	$ 0.79	$ 1.39	$ 1.54	$ 2.85	$ 3.06
Diluted net income per limited partner unit	$ 0.71	$ 0.78	$ 1.36	$ 1.51	$ 2.79	$ 3.00

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. The amount of income allocated to our limited partnership 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 $2.83 per unit, our general partner's distribution is forecast to be approximately $33.9 million annually, of which $29.4 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. For distribution rates where EITF 03-06 does not apply,

each $0.05 per unit annual increase in the distribution over $2.83 per unit decreases net income available for limited partners by approximately $3.7 million ($0.05 per unit) on an annualized basis.

10. *Long-term Incentive Plans*. Effective January 1, 2006 we adopted SFAS 123(R) Share-Based Payment, resulting in a cumulative effect of change in accounting principle gain of $6.3 million. 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 majority of the phantom units awarded under the 2005 plan primarily vest in various percentages on the later of 1) May 2007, May 2009, and May 2010, or 2) achievement of annualized distribution levels of $2.60, $2.80, $3.00, respectively, and for certain grants, $3.10 per unit. The majority of the phantom units have a final service period vesting in 2011. In addition to exceeding the distribution level of $2.80, it has been deemed probable that the $3.10 distribution level will be achieved. Accordingly, guidance includes, for phantom units tied to performance levels of $3.10 or less, an accrual over the corresponding service period. For 2006, the guidance includes approximately $36.3 million of principally non-cash expense associated with these phantom units. The earliest significant vesting event for outstanding grants will occur in 2007.

    The actual amount of LTIP expense amortization in any given year will be directly influenced by our unit price at the end of each reporting period and the amount of amortization in the early years, and will also be increased if a determination is made that achievement of any of the remaining performance thresholds is probable. Therefore, market variables could cause actual net income to differ materially from our projections.

11. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the 2006 guidance ranges for EBITDA and EBIT to net income.

	Calendar 2006 Guidance					
	Three Months Ending June 30, 2006		Six Months Ending December 31, 2006		Twelve Months Ending December 31, 2006	
	Low	High	Low	High	Low	High
	(in millions)					
Reconciliation to Net Income						
EBITDA	$ 106.7	$ 116.7	$ 212.6	$ 232.6	$ 419.6	$ 449.6
Depreciation and amortization	(23.1)	(22.7)	(48.0)	(47.2)	(92.7)	(91.5)
EBIT	83.6	94.0	164.6	185.4	326.9	358.1
Interest expense	(18.6)	(17.8)	(40.3)	(38.7)	(74.2)	(71.8)
Net Income	$ 65.0	$ 76.2	$ 124.3	$ 146.7	$ 252.7	$ 286.3

Preliminary 2007 Guidance

This preliminary adjusted EBITDA guidance for 2007 is based on 1) continued operating and financial performance of our existing assets in line with recent performance trends, 2) achievement of targeted performance levels for recent acquisitions and the pending BP Asset acquisition that has not closed and 3) contributions from expansion capital expenditures in line with our expectations. In that regard, we would expect daily pipeline shipments to average approximately 270,000 Bbl/d for Basin, 47,000 Bbl/d for All American and 145,000 bbl/d for Capline, and gathering and marketing volumes to average approximately 730,000 Bbl/d.

Projected operating results for the GMT&S segment incorporate the expectation that market conditions will remain generally favorable, although not as favorable as the market conditions experienced over most of 2005 and 2006 to date.

The following table summarizes the range of selected key financial data of our preliminary sustainable projections for calendar year 2007.

Preliminary Calendar 2007 Guidance (in millions)

	Low	High
Adjusted EBITDA	$ 480	$ 520
Depreciation and amortization	(102)	(97)
Interest expense	(92)	(87)
Adjusted Net Income	$ 286	$ 336
Maintenance Capital Expenditures	$ 25	$ 25

Our preliminary guidance for interest expense is based on our projected capital structure as of June 9, 2006, the current market outlook for floating interest rates and approved capital projects for 2007. Our preliminary guidance for depreciation and amortization is based on projected depreciation from our present asset base, and continued development of our portfolio of projects. Our preliminary guidance for maintenance capital expenditures is based on our estimated level of recurring expenditures of approximately $25 million. Adjusted net income and adjusted EBITDA exclude selected items impacting comparability such as LTIP's, gains or losses from Foreign Exchange Revaluations and SFAS 133 (see Note 5 above). It is impractical to forecast selected items impacting comparability to arrive at net income and EBITDA and therefore adjusted net income and adjusted EBITDA are presented to provide information with respect to both the performance and fundamental business activities.

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" and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. However, the absence of these words 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:

- the success of our risk management activities;
- 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 and trade counterparties;
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline system;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by us and third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- demand for natural gas or 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 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 and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- unanticipated changes in crude oil market structure and volatility (or lack thereof);
- the impact of current and future laws, rulings and governmental regulations;
- the effects of competition;
- continued creditworthiness of, and performance by, our counterparties;
- interruptions in service and fluctuations in rates of third party pipelines;
- increased costs or lack of availability 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 Plans;
- the currency exchange rate of the Canadian dollar;
- the impact of crude oil and natural gas price fluctuations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- general economic, market or business conditions; and
- other factors and uncertainties inherent in the marketing, transportation, terminalling, gathering and storage of crude oil and liquefied petroleum gas.

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: June 12, 2006	By:	/s/ PHIL KRAMER
		Name: Phil Kramer
		Title: *Executive Vice President and Chief Financial Officer*