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		Three Months Ending December 31, 2006		Twelve Months Ending December 31, 2006	
		Low	High	Low	High	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	Guidance (1)		
	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)				
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	80.9	82.1	82.1	78.9	78.9
Basic net income per limited partner unit	$0.63	$0.75	$0.62	$0.74	$2.89	$3.03
Diluted net income per limited partner unit	$0.63	$0.74	$0.61	$0.73	$2.86	$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 $2.90 per unit and including 3.7 million units issued in the third quarter, our general partner's distribution is forecast to be approximately $41.2 million annually, of which $36.4 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 $2.90 per unit decreases net income available for limited partners by approximately $4.0 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 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 achieving the distribution level of $2.90, 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 at an assumed market price of $45.00 per unit. For 2006, the guidance includes approximately $34.4 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 as well as new unit grants. Therefore, actual net income could 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.

	Guidance					
	Three Months Ending September 30, 2006		Three Months Ending December 31, 2006		Twelve Months Ending December 31, 2006	
	Low	High	Low	High	Low	High
	(in millions)					
Reconciliation to Net Income						
EBITDA	$106.0	$116.0	$106.4	$116.4	$432.3	$452.3
Depreciation and amortization	(24.8)	(24.4)	(25.8)	(25.4)	(93.5)	(92.7)
EBIT	81.2	91.6	80.6	91.0	338.8	359.6
Interest expense	(20.4)	(19.6)	(20.4)	(19.6)	(74.1)	(72.5)
Net Income	$60.8	$72.0	$60.2	$71.4	$264.7	$287.1

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: August 1, 2006	By:	/s/ PHIL KRAMER
		Name: Phil Kramer
		Title: *Executive Vice President and Chief Financial Officer*

Exhibit 99.1

Contacts: Phillip D. Kramer
Executive VP and CFO
713/646-4560—800/564-3036

Brad A. Thielemann
Manager, Special Projects
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FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports Strong Financial Results for Second Quarter 2006— Net Income Climbs 29%; Net Income Per Diluted Unit Increases 9%; EBITDA Up 25%

(Houston—August 1, 2006) Plains All American Pipeline, L.P. (NYSE: PAA) reported second quarter 2006 net income of $80.3 million, equivalent to $0.81 per diluted limited partner unit. These financial results represent increases of 29% and 9%, respectively, over net income of $62.3 million, or $0.74 per diluted limited partner unit, for the second quarter of 2005. For the first six months of 2006, the Partnership reported net income of $143.7 million, or $1.53 per diluted limited partner unit, representing increases of 51% and 21%, respectively, over net income of $95.1 million, or $1.26 per diluted limited partner unit, for the first six months of 2005.

As reported, earnings before interest, taxes, depreciation and amortization ("EBITDA") for the second quarter of 2006 were $119.6 million, an increase of 25% as compared with EBITDA of $95.6 million for the second quarter of 2005. EBITDA for the first six months of 2006 was $219.9 million, an increase of 36% as compared with EBITDA of $162.1 million for the first six months of 2005. (See the section of this release entitled "Non-GAAP Financial Measures" and the attached tables for a discussion of EBITDA and other non-GAAP financial measures, and reconciliations of such measures to the comparable GAAP measures.)

"Although we are only seven months into the year, 2006 has already been a very active and productive year for the Partnership," said Greg L. Armstrong, Chairman and CEO of Plains All American. "We have achieved strong operating and financial results and made significant progress on our $275 million expansion capital program. In the last four months, we have announced or closed seven predominantly fee-based acquisitions for aggregate consideration of approximately $572 million. Of major significance, we entered into agreements to acquire Pacific Energy Partners in a transaction valued at approximately $2.4 billion. We believe these activities set the stage for continued growth in our fundamental business as well as in our distributions to unitholders." Armstrong noted that the Partnership recently declared an increase in its quarterly cash distribution to $0.725 per unit ($2.90 per unit on an annualized basis), which marked the Partnership's ninth consecutive quarterly distribution increase and the sixteenth increase in the last twenty-two quarters.

Armstrong also commented, "The Partnership's generation of cash flow in excess of distributions, coupled with proactive equity and debt financings to fund acquisitions and capital expenditures, has allowed us to maintain a strong capital structure and a high level of liquidity and financial flexibility."

The Partnership's reported results include the impact of various items that affect comparability between reporting periods. Adjusting for selected items impacting comparability, the Partnership's second quarter 2006 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $88.9 million, $1.03 per diluted unit and $128.2 million, respectively. By way of comparison, the Partnership's second quarter 2005 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $82.1 million, $1.11 per diluted unit, and $115.4 million, respectively. On a comparable basis, second quarter 2006 adjusted net income increased 8%, adjusted net income per diluted limited partner unit decreased 7% and adjusted EBITDA increased 11% over second quarter 2005.

The Partnership's adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first six months of 2006 were $157.3 million, $1.85 per diluted unit and $233.5 million, respectively. Similarly, the Partnership's adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first six months of 2005 were $131.4 million, $1.78 per diluted unit and $198.4 million, respectively. On a comparable basis, adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first six months of 2006 increased 20%, 4% and 18%, respectively, over the first six months of 2005.

The following table highlights selected items that the Partnership believes impact the comparability of financial results between reporting periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in millions, except per unit data)			
Long-Term Incentive Plan ("LTIP") charge	$ (6.2)	$ (7.9)	$ (16.8)	$ (10.2)
Cumulative effect of change in accounting principle—LTIP(1)	—	—	6.3	—
Gain on foreign currency revaluation(2)	—	1.0	—	0.2
SFAS 133 mark-to-market adjustment	(2.4)	(12.9)	(3.1)	(26.3)
Total	$ (8.6)	$ (19.8)	$ (13.6)	$ (36.3)
Per Basic Limited Partner Unit(3)	*$ (0.22)*	*$ (0.37)*	*$ (0.32)*	*$ (0.54)*
Per Diluted Limited Partner Unit(3)	*$ (0.22)*	*$ (0.37)*	*$ (0.32)*	*$ (0.52)*

Note: Figures may not sum due to rounding.

(1) During the first quarter of 2006, we adopted SFAS No. 123(R) (revised) "Share Based Payment," which requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued expense and related liability, and therefore resulted in a non-cash gain of $6.3 million in the first quarter of 2006.

(2) Selected items impacting comparability for the first six months of 2006 excludes a loss of approximately $0.9 million on foreign currency revaluation that was previously included in the first quarter 2006.

(3) For the quarter ended June 30, 2006, the Partnership's net income exceeded the cash distribution paid during such periods, which required the application of *Emerging Issues Task Force Issue No. 03-06: "Participating Securities and the Two-Class Method under FASB Statement No. 128"* ("EITF 03-06"). This calculation does not impact the Partnership's aggregate net income or EBITDA, but does reduce the Partnership's net income per limited partner unit. The application of EITF 03-06 negatively impacted basic and diluted earnings per limited partner unit by $0.11 and $0.09 for the second quarter and $0.15 and $0.01 for the first six months of 2006 and 2005, respectively. This impact is included as a selected item impacting net income per limited partner unit.

The following table presents certain selected financial information by segment for the second quarter reporting periods:

	Three Months Ended June 30, 2006		Three Months Ended June 30, 2005	
	Pipeline Operations	Gathering, Marketing, Terminalling & Storage Operations[4]	Pipeline Operations	Gathering, Marketing, Terminalling & Storage Operations[4]
	(in millions)		(in millions)	
Revenues[1]	$ 274.9	$ 4,655.3	$ 260.5	$ 6,931.0
Purchases and related costs[1]	(165.6)	(4,532.2)	(167.8)	(6,834.7)
Field operating costs (excluding LTIP charge)	(45.2)	(40.8)	(37.7)	(29.1)
LTIP charge—operations	(0.2)	(0.4)	(0.3)	(0.7)
Segment G&A expenses (excluding LTIP charge)[2]	(8.5)	(13.3)	(9.2)	(9.9)
LTIP charge—general and administrative	(2.3)	(3.3)	(4.1)	(2.9)
Segment profit	$ 53.1	$ 65.3	$ 41.4	$ 53.7
SFAS 133 mark-to-market impact[3]	$ —	$ (2.4)	$ —	$ (12.9)
Maintenance capital	$ 3.3	$ 1.1	$ 2.5	$ 1.5

(1) Includes inter-segment amounts. We have adopted EITF 04-13, which impacts the comparability of our revenues, effective April 1, 2006. Revenues for the three months ended June 30, 2005 include buy/sell transactions of $40 million and $3,706.1 million in the Pipeline segment and the Gathering, Marketing, Terminalling & Storage segment, respectively.

(2) Segment general and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit. The SFAS 133 mark-to-market adjustment is primarily based upon crude oil prices at the end of the period and is related to the non-effective portion of our cash flow hedges, as well as certain derivative contracts that do not qualify under SFAS 133 as cash flow hedges. The net gain or loss related to these derivative instruments is principally offset by physical positions in future periods.

(4) Gains/losses on foreign currency revaluation are included in the Gathering, Marketing, Terminalling & Storage segment.

Excluding selected items impacting comparability in both periods, adjusted segment profit from pipeline operations in the second quarter of 2006 was $55.6 million versus $45.8 million for the second quarter of 2005 on average daily volumes of 2.0 million barrels per day versus 1.8 million barrels per day. This increase is primarily a result of increased throughput volumes on certain major pipeline systems. Adjusted segment profit from gathering, marketing, terminalling and storage operations for the second quarter of 2006 was $71.4 million, up approximately 3% over the corresponding period in 2005. Segment performance was predominantly driven by favorable market conditions, successful execution of our risk management strategies and the contributions from recent acquisitions.

The following table presents certain selected financial information by segment for the first six-month reporting periods:

	Six Months Ended June 30, 2006		Six Months Ended June 30, 2005	
	Pipeline Operations	Gathering, Marketing, Terminalling & Storage Operations[4]	Pipeline Operations	Gathering, Marketing, Terminalling & Storage Operations[4]
	(in millions)		(in millions)	
Revenues[1]	$ 559.9	$ 13,043.9	$ 507.7	$ 13,357.2
Purchases and related costs[1]	(354.2)	(12,809.2)	(319.5)	(13,204.1)
Field operating costs (excluding LTIP charge)	(89.9)	(77.3)	(71.7)	(58.6)
LTIP charge—operations	(0.6)	(1.1)	(0.4)	(0.9)
Segment G&A expenses (excluding LTIP charge)[2]	(17.3)	(26.8)	(19.4)	(20.0)
LTIP charge—general and administrative	(6.8)	(8.3)	(5.3)	(3.6)
Segment profit	$ 91.1	$ 121.2	$ 91.4	$ 70.0
SFAS 133 mark-to-market impact[3]	$ —	$ (3.1)	$ —	$ (26.3)
Maintenance capital	$ 6.2	$ 2.9	$ 5.3	$ 2.7

(1) Includes inter-segment amounts. We have adopted EITF 04-13, which impacts the comparability of our revenues, effective April 1, 2006. Revenues include buy/sell transactions in the six months ended June 30, 2006 of $45.3 million and $4,717.7 million and in the six months ended June 30, 2005 of $73.6 million and $7,125.2 million in the Pipeline segment and the Gathering, Marketing, Terminalling & Storage segment, respectively.

(2) Segment general and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit. The SFAS 133 mark-to-market adjustment is primarily based upon crude oil prices at the end of the period and is related to the non-effective portion of our cash flow hedges, as well as certain derivative contracts that do

not qualify under SFAS 133 as cash flow hedges. The net gain or loss related to these derivative instruments is principally offset by physical positions in future periods.

(4) Gains/losses on foreign currency revaluation are included in the Gathering, Marketing, Terminalling & Storage segment.

The Partnership's basic weighted average units outstanding for the second quarter of 2006 totaled 77.0 million (77.8 million diluted) as compared to 67.9 million (69.3 million diluted) in last year's second quarter. At June 30, 2006, the Partnership had approximately 77.3 million units outstanding, long-term debt of $1,255.1 million and a long-term debt to total capitalization ratio of approximately 45%. Including its recent direct equity placement, the Partnership has approximately 81 million common units outstanding.

On July 14, 2006, the Partnership declared a cash distribution of $0.725 per unit ($2.90 per unit on an annualized basis) on its outstanding limited partner units. The distribution will be payable on August 14, 2006, to holders of record of such units at the close of business on August 4, 2006. The distribution represents an increase of 11.5% over the August 2005 distribution and 2.5% over the May 2006 distribution.

The Partnership today furnished a current report on Form 8-K, which included material in this press release and financial and operational guidance for the third quarter and full year 2006. A copy of the Form 8-K is available on the Partnership's website at www.paalp.com.

Non-GAAP Financial Measures

In this release, the Partnership's EBITDA disclosure is not presented in accordance with generally accepted accounting principles and is not intended to be used in lieu of GAAP presentations of results of operations or cash provided by operating activities. EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as 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 present selected items that impact the comparability of our operating results as additional information that may be helpful to your understanding of our financial results. We consider an understanding of these selected items impacting comparability to be material to our evaluation of our operating results and prospects. Although we present selected items that we consider in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions and numerous other factors. These types of variations are not separately identified in this release, but will be discussed in management's discussion and analysis of operating results in our Quarterly Report on Form 10-Q.

A reconciliation of EBITDA to net income and cash flow from operating activities for the periods presented is included in the tables attached to this release. In addition, the Partnership maintains on its website (www.paalp.com) a reconciliation of all non-GAAP financial information, such as EBITDA, that it reconciles to the most comparable GAAP measures. To access the information, investors should click on the "Investor Relations" link on the Partnership's home page and then the "Non-GAAP Reconciliation" link on the Investor Relations page.

Conference Call

The Partnership will host a conference call to discuss the results and other forward-looking items on Tuesday, August 1, 2006. Specific items to be addressed in this call include:

1. A brief review of the Partnership's second quarter performance;
2. A status report on major expansion projects and recent acquisition activity;
3. A discussion of capitalization and liquidity;
4. A review of financial and operating guidance for the third quarter and full year 2006; and
5. Comments regarding the Partnership's outlook for the future.

The call will begin at 10:00 AM (Central). To participate in the call, please dial 877-709-8150, or, for international callers, 201-689-8354 at approximately 9:55 AM (Central). No password or reservation number is required.

Webcast Instructions

To access the Internet webcast, please go to the Partnership's website at www.paalp.com, choose "Investor Relations", and then choose "Conference Calls". Following the live webcast, the call will be archived for a period of sixty (60) days on the Partnership's website.

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial 877-660-6853, or, for international callers, 201-612-7415, and enter acct # 232 and replay # 207308. The replay will be available beginning Tuesday, August 1, 2006, at approximately 1:00 PM (Central) and continue until 10:59 PM (Central) Monday, August 7, 2006.

Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this news release are forward-looking statements that involve certain risks and uncertainties that could cause actual results to differ materially from results anticipated in the forward-looking statements. These risks and uncertainties include, among other things: 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, 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 discussed in the Partnership's filings with the Securities and Exchange Commission.

Plains All American Pipeline, L.P. is engaged in interstate and intrastate crude oil transportation and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products, in the United States and Canada. Through its 50% ownership in PAA/Vulcan Gas Storage LLC, the Partnership is also engaged in the development and operation of natural gas storage facilities. The Partnership's common units are traded on the New York Stock Exchange under the symbol "PAA." The Partnership is headquartered in Houston, Texas.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FINANCIAL SUMMARY (unaudited)

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
REVENUES[1]	$ 4,892.4	$ 7,160.7	$ 13,527.8	$ 13,799.2
COSTS AND EXPENSES				
Purchases and related costs	4,660.0	6,971.7	13,087.4	13,457.9
Field operating costs	86.6	67.8	168.9	131.6
General and administrative expenses	27.4	26.1	59.2	48.2
Depreciation and amortization	21.3	19.1	42.9	38.2
Total costs and expenses	4,795.3	7,084.7	13,358.4	13,675.9
OPERATING INCOME	97.1	76.0	169.4	123.3
OTHER INCOME/(EXPENSE)				
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.1	—	0.9	—
Interest expense	(18.0)	(14.2)	(33.3)	(28.8)
Interest income and other income (expense), net	0.1	0.5	0.4	0.6
Income before cumulative effect of change in accounting principle	80.3	62.3	137.4	95.1
Cumulative effect of change in accounting principle	—	—	6.3	—
NET INCOME	$ 80.3	$ 62.3	$ 143.7	$ 95.1
NET INCOME—LIMITED PARTNERS	$ 71.4	$ 57.6	$ 128.2	$ 86.9
NET INCOME—GENERAL PARTNER	$ 8.9	$ 4.7	$ 15.5	$ 8.2
BASIC NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.82	$ 0.76	$ 1.47	$ 1.27
Cumulative effect of change in accounting principle	—	—	0.08	—
Basic net income per limited partner unit	$ 0.82	$ 0.76	$ 1.55	$ 1.27
DILUTED NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.81	$ 0.74	$ 1.45	$ 1.26
Cumulative effect of change in accounting principle	—	—	0.08	—
Diluted net income per limited partner unit	$ 0.81	$ 0.74	$ 1.53	$ 1.26
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	77.0	67.9	75.5	67.7
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	77.8	69.3	76.3	68.7

(1) Revenues include buy/sell transactions of $3.7 billion in the three months ended June 30, 2005 and $4.8 billion and $7.2 billion for six months ended June 30, 2006 and 2005, respectively.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FINANCIAL SUMMARY (unaudited)

OPERATING DATA (in thousands)[1]
Average Daily Volumes (barrels)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Pipeline activities:				
Tariff activities				
All American	53	50	48	52
Basin	330	283	322	280
Capline	178	143	132	152
Cushing to Broome	79	84	75	54
North Dakota/Trenton	87	73	85	67
West Texas/New Mexico Area Systems[2]	478	435	460	418
Canada	253	248	246	258
Other	458	421	452	415
Pipeline margin activities	85	67	88	71
Pipeline activities total	2,001	1,804	1,908	1,767
GMT&S activities:				
Crude oil lease gathering	652	628	637	625
LPG sales and third party processing	47	26	66	55
Waterborne foreign crude imported	43	52	50	57
GMT&S activities total	742	706	753	737

(1) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(in millions)

	June 30, 2006	December 31, 2005
ASSETS		
Current assets	$ 3,176.4	$ 1,805.2
Property and equipment, net	2,147.5	1,857.2
Pipeline linefill in owned assets	200.4	180.2
Inventory in third party assets	80.4	71.5
Investment in PAA/Vulcan Gas Storage, LLC	124.4	113.5
Goodwill	179.6	47.4
Other long-term assets, net	109.6	45.3
Total assets	$ 6,018.3	$ 4,120.3
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 3,179.4	$ 1,793.3
Long-term debt under credit facilities and other	58.4	4.7
Senior notes, net of unamortized discount	1,196.7	947.0
Other long-term liabilities and deferred credits	57.7	44.6
Total liabilities	4,492.2	2,789.6
Partners' capital	1,526.1	1,330.7
Total liabilities and partners' capital	$ 6,018.3	$ 4,120.3

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT
(in millions, except per unit data)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 80.3	$ 62.3	$ 143.7	$ 95.1
Less: General partner's incentive distribution paid	(7.4)	(3.5)	(12.9)	(6.4)
Subtotal	72.9	58.8	130.8	88.7
General partner 2% ownership	(1.5)	(1.2)	(2.6)	(1.8)
Net income available to limited partners	71.4	57.6	128.2	86.9
Pro forma additional general partner's distribution[1]	(8.2)	(6.2)	(11.2)	(0.6)
Net income available for limited partners under EITF 03-06	63.2	51.4	117.0	86.3
Less: Limited partner 98% portion of cumulative effect of change in accounting principle	—	—	6.2	—
Limited partner net income before cumulative effect of change in accounting principle	$ 63.2	$ 51.4	$ 110.8	$ 86.3
Denominator:				
Basic weighted average number of limited partner units outstanding	77.0	67.9	75.5	67.7
Effect of dilutive securities:				
Weighted average 2005 Long-Term Incentive Plan ("LTIP") units	0.8	1.4	0.8	1.0
Diluted weighted average number of limited partner units outstanding	77.8	69.3	76.3	68.7

Basic net income per limited partner unit before cumulative effect of change in accounting principle[1]	$ 0.82	$ 0.76	$ 1.47	$ 1.27
Cumulative effect of change in accounting principle per limited partner unit	—	—	0.08	—
Basic net income per limited partner unit	$ 0.82	$ 0.76	$ 1.55	$ 1.27
Diluted net income per limited partner unit before cumulative effect of change in accounting principle[1]	$ 0.81	$ 0.74	$ 1.45	$ 1.26
Cumulative effect of change in accounting principle per limited partner unit	—	—	0.08	—
Diluted net income per limited partner unit	$ 0.81	$ 0.74	$ 1.53	$ 1.26

(1) Reflects pro forma full distribution of earnings under EITF 03-06. The application of EITF 03-06 negatively impacted basic and diluted earnings per limited partner unit by approximately $0.11 and $0.09 for the three months ended and $0.15 and $0.01 for the six months ended June 30, 2006 and 2005, respectively.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Earnings before interest, taxes, depreciation and amortization (“EBITDA”)				
Net income reconciliation				
EBITDA	$ 119.6	$ 95.6	$ 219.9	$ 162.1
Depreciation and amortization	(21.3)	(19.1)	(42.9)	(38.2)
Earnings before interest and taxes (“EBIT”)	98.3	76.5	177.0	123.9
Interest expense	(18.0)	(14.2)	(33.3)	(28.8)
Net income	$ 80.3	$ 62.3	$ 143.7	$ 95.1
Cash flow from operating activities reconciliation				
EBITDA	$ 119.6	$ 95.6	$ 219.9	$ 162.1
Interest expense	(18.0)	(14.2)	(33.3)	(28.8)
Net change in assets and liabilities, net of acquisitions	(295.3)	(281.9)	(844.6)	(622.1)
Other items to reconcile to cash flows from operating activities:				
Equity earnings in PAA/Vulcan Gas Storage, LLC	(1.1)	—	(0.9)	—
Net cash paid for terminated interest rate hedging instruments	—	(0.9)	—	(0.9)
Net (gain) / loss on foreign currency revaluation	0.9	(1.4)	1.8	(0.9)
SFAS 133 mark-to-market adjustment	2.4	12.9	3.1	26.3
Cumulative effect of change in accounting principle	—	—	(6.3)	—
LTIP charge	6.2	7.9	16.8	10.2
Non-cash amortization of terminated interest rate hedging instruments	0.4	0.4	0.8	0.8
Net cash used in operating activities	$ (184.9)	$ (181.6)	$ (642.7)	$ (453.3)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
Funds flow from operations (“FFO”)				
Net Income	$ 80.3	$ 62.3	$ 143.7	$ 95.1
Equity earnings in PAA/Vulcan Gas Storage, LLC	(1.1)	—	(0.9)	—
Depreciation and amortization	21.3	19.1	42.9	38.2
Non-cash amortization of terminated interest rate hedging instruments	0.4	0.4	0.8	0.8
FFO	100.9	81.8	186.5	134.1
Maintenance capital expenditures	(4.4)	(4.0)	(9.1)	(8.0)
FFO after maintenance capital expenditures	$ 96.5	$ 77.8	$ 177.4	$ 126.1

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS (Continued)
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Selected items impacting comparability				
LTIP charge	$ (6.2)	$ (7.9)	$ (16.8)	$ (10.2)
Cumulative effect of change in accounting principle—LTIP	—	—	6.3	—
Gain on foreign currency revaluation	—	1.0	—	0.2
SFAS 133 mark-to-market adjustment	(2.4)	(12.9)	(3.1)	(26.3)
Selected items impacting comparability	(8.6)	(19.8)	(13.6)	(36.3)
GP 2% portion of selected items impacting comparability	0.2	0.4	0.3	0.7
LP 98% portion of selected items impacting comparability	$ (8.4)	$ (19.4)	$ (13.3)	$ (35.6)
Impact to basic net income per limited partner unit[1]	$ (0.22)	$ (0.37)	$ (0.32)	$ (0.54)
Impact to diluted net income per limited partner unit[1]	$ (0.22)	$ (0.37)	$ (0.32)	$ (0.52)

(1) The application of EITF 03-06 negatively impacted basic and diluted earnings per limited partner unit by approximately $0.11 and $0.09 for the three months ended and $0.15 and $0.01 for the six months ended June 30, 2006 and 2005, respectively.

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net income and earnings per limited partner unit excluding selected items impacting comparability				
Net income	$ 80.3	$ 62.3	$ 143.7	$ 95.1
Selected items impacting comparability	8.6	19.8	13.6	36.3
Adjusted net income	$ 88.9	$ 82.1	$ 157.3	$ 131.4
Net income available for limited partners under EITF 03-06	$ 63.2	$ 51.4	$ 117.0	$ 86.3
Limited partners 98% of selected items impacting comparability	8.4	19.4	13.3	35.6
Pro forma additional general partner distribution under EITF 03-06	8.2	6.2	11.2	0.6
Adjusted limited partners net income	$ 79.8	$ 77.0	$ 141.5	$ 122.5
Adjusted basic net income per limited partner unit	$ 1.04	$ 1.13	$ 1.87	$ 1.81
Adjusted diluted net income per limited partner unit	$ 1.03	$ 1.11	$ 1.85	$ 1.78
Basic weighted average units outstanding	77.0	67.9	75.5	67.7
Diluted weighted average units outstanding	77.8	69.3	76.3	68.7

FINANCIAL DATA RECONCILIATIONS (Continued)
(in millions, except per unit data)

	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
EBITDA excluding selected items impacting comparability				
EBITDA	$ 119.6	$ 95.6	$ 219.9	$ 162.1
Selected items impacting comparability	8.6	19.8	13.6	36.3
Adjusted EBITDA	$ 128.2	$ 115.4	$ 233.5	$ 198.4

	Three Months Ended June 30, 2006 Pipeline	Three Months Ended June 30, 2006 GMT&S	Six Months Ended June 30, 2006 Pipeline	Six Months Ended June 30, 2006 GMT&S
2006 Segment profit excluding selected items impacting comparability				
Reported segment profit	$ 53.1	$ 65.3	$ 91.1	$ 121.2
Selected items impacting comparability of segment profit:				
LTIP charge	2.5	3.7	7.4	9.4
SFAS 133 mark-to-market adjustment	—	2.4	—	3.1
Segment profit excluding selected items impacting comparability	$ 55.6	$ 71.4	$ 98.5	$ 133.7

	Three Months Ended June 30, 2005 Pipeline	Three Months Ended June 30, 2005 GMT&S	Six Months Ended June 30, 2005 Pipeline	Six Months Ended June 30, 2005 GMT&S
2005 Segment profit excluding selected items impacting comparability				
Reported segment profit	$ 41.4	$ 53.7	$ 91.4	$ 70.0
Selected items impacting comparability of segment profit:				
LTIP charge	4.4	3.5	5.7	4.5
Gain on foreign currency revaluation	—	(1.0)	—	(0.2)
SFAS 133 mark-to-market adjustment	—	12.9	—	26.3
Segment profit excluding selected items impacting comparability	$ 45.8	$ 69.1	$ 97.1	$ 100.6

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