PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
November 02, 2006

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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) November 2, 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))

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Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press release dated November 2, 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 third 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 fourth quarter (which supersedes guidance in our 8-K furnished on August 1, 2006) of calendar 2006 and resulting financial performance for the full year of calendar 2006. The Partnership s guidance excludes any contribution from the proposed merger with Pacific Energy Partners, L.P. (Pacific Energy) announced June 12, 2006. Note 12 includes the estimated impact of the Pacific Energy acquisition to our fourth quarter, assuming the acquisition closes on November 15, 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.

Update of Fourth Quarter 2006 Estimates

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, gains and losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments) to the extent known, interest expense related to our New Senior Notes (as defined in Note 7) and interest income from the investment of the net proceeds from the New Senior Notes on EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three month period ending December 31, 2006 is 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 November 1, 2006. We undertake no obligation to publicly update or revise any forward-looking statements.

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Plains All American Pipeline, L.P.
Operating and Financial Guidance
(in millions, except per unit data)

	Actual Nine Months Ended 09/30/06	Guidance* Three Months Ending December 31, 2006 Low	High	Twelve Months Ending December 31, 2006 Low	High
Pipeline					
Net revenues	$ 319.4	$ 110.3	$ 111.7	$ 429.7	$ 431.1
Field operating costs	(138.1)	(47.2)	(46.6)	(185.3)	(184.7)
General and administrative expenses	(38.0)	(12.4)	(12.2)	(50.4)	(50.2)
	143.3	50.7	52.9	194.0	196.2
Gathering, Marketing, Terminalling & Storage					
Net revenues	382.8	115.0	121.4	497.8	504.2
Field operating costs	(122.4)	(43.0)	(42.4)	(165.4)	(164.8)
General and administrative expenses	(54.2)	(19.9)	(19.6)	(74.1)	(73.8)
	206.2	52.1	59.4	258.3	265.6
Segment Profit	349.5	102.8	112.3	452.3	461.8
Depreciation and amortization expense	(67.1)	(27.0)	(26.6)	(94.1)	(93.7)
Interest expense existing notes and facilities	(52.5)	(20.1)	(19.3)	(72.6)	(71.8)
Interest expense New Senior Notes (See Note 7 & 8)		(10.8)	(10.8)	(10.8)	(10.8)
Interest income New Senior Notes (See Note 7 & 8)		8.7	8.7	8.7	8.7
Equity earnings (loss) in PAA / Vulcan Gas Storage, LLC	2.2	2.8	3.3	5.0	5.5
Other Income (Expense)	0.7			0.7	0.7
Income Before Cumulative Effect of Change in Accounting Principle	**232.8**	**56.4**	**67.6**	**289.2**	**300.4**
Cumulative Effect of Change in Accounting Principle	6.3			6.3	6.3
Net Income	**$ 239.1**	**$ 56.4**	**$ 67.6**	**$ 295.5**	**$ 306.7**
Net Income to Limited Partners	$ 212.7	$ 44.4	$ 55.4	$ 257.1	$ 268.1
Basic Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	77.0	81.0	81.0	78.0	78.0
Net Income Per Unit **	$ 2.45	$ 0.55	$ 0.68	$ 3.09	$ 3.16
Diluted Net Income Per Limited Partner Unit					

Weighted Average Units Outstanding	77.8	82.0	82.0	78.8	78.8
Net Income Per Unit **	$ 2.43	$ 0.54	$ 0.67	$ 3.06	$ 3.13
EBIT	**$ 291.6**	**$ 78.6**	**$ 89.0**	**$ 370.2**	**$ 380.6**
EBITDA	**$ 358.7**	**$ 105.6**	**$ 115.6**	**$ 464.3**	**$ 474.3**

Selected Items Impacting Comparability					
LTIP charge	$ (27.1)	$ (9.4)	$ (9.4)	$ (36.5)	$ (36.5)
Cumulative Effect of Change in Accounting Principle	6.3			6.3	6.3
SFAS 133 Mark-to-Market Adjustment	14.8			14.8	14.8
Interest expense New Senior Notes		(10.8)	(10.8)	(10.8)	(10.8)
Interest income New Senior Notes		8.7	8.7	8.7	8.7
	$ (6.0)	$ (11.5)	$ (11.5)	$ (17.5)	$ (17.5)

Excluding Selected Items Impacting Comparability					
Adjusted EBITDA	$ 364.7	$ 115.0	$ 125.0	$ 479.7	$ 489.7
Adjusted Net Income	$ 245.1	$ 67.9	$ 79.1	$ 313.0	$ 324.2
Adjusted Basic Net Income per Limited Partner Unit	$ 2.84	$ 0.69	$ 0.82	$ 3.53	$ 3.66
Adjusted Diluted Net Income per Limited Partner Unit	$ 2.81	$ 0.68	$ 0.81	$ 3.49	$ 3.62

* The projected average foreign exchange rate is $1.15 CAD to $1 USD. The rate as of November 1, 2006 was 1.13 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.

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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
Bbls/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
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.

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

	Calendar 2006		
	Actual	Guidance	
	Nine Months Ended September 30	Three Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (000 Bbls/d)			
All American	49	45	48
Basin	323	350	330
BOA / CAM	57(1)	172	86
Capline	149	185	158
Cushing to Broome	73	80	75
North Dakota / Trenton	88	92	89
West Texas / New Mexico area systems (2)	445	428	441
Canada	247	254	250
Other	553	580(3)	558
	1,984	2,186	2,035
Average Segment Profit ($/Bbl)			
As Reported	$ 0.27	$ 0.26(4)	$ 0.26(4)
Excluding Selected Items Impacting Comparability	$ 0.29	$ 0.28(4)	$ 0.29(4)

(1) Acquisition effective in third quarter of 2006.

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

(3) Includes approximately 45,000 Bbl/d related to assets purchased from Chevron Pipe Line Company effective September 1, 2006.

(4) Mid-point of guidance.

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Segment profit is forecast using the volume assumptions in the table above, priced at tariff rates currently received, 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 fourth quarter segment profit, the following table provides a volume sensitivity analysis of three systems representing approximately 28% of total pipeline net revenues.

Volume Sensitivity Analysis

System	**Incr (Decr) in Volume (Bbls/d)**	**% of System Total**	**Incr (Decr) in Segment Profit Guidance (in millions)**
All American	5,000	11%	$ 0.9
Basin	20,000	6%	0.5
Capline	10,000	5%	0.3

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 period ending December 31, 2006 reflect an expected continuation of the current contango market and favorable market conditions (relative to our asset base and business model) 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 nine months of 2006. Unexpected changes in market structure or volatility (or lack thereof) could cause actual results to differ materially from forecasted results.

	Calendar 2006		
	Actual	Guidance	
	Nine Months Ended September 30	Three Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (000 Bbls/d)			
Crude Oil Lease Gathering	639	650	642
LPG Sales and Third Party Processing	60	90	68
Waterborne foreign crude imported	59	50	57
	758	790	767
Segment Profit per Barrel ($/Bbl)			
As Reported	$ 1.00	$ 0.77(1)	$ 0.94(1)
Excluding Selected Items Impacting Comparability	$ 1.00	$ 0.83(1)	$ 0.95(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. 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 the three months ending December 31, 2006, a 15,000 Bbl/d variance in lease gathering volumes would impact fourth-quarter segment profits by approximately $1.0 million. A $0.01 variance in the aggregate average per-barrel margin would impact fourth-quarter segment profits by approximately $0.7 million.

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 furniture 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.* 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. Capital expenditures for expansion projects are forecast to be approximately $310 million during calendar 2006 of which $214 million was incurred in the first nine months of 2006. Following are some of the more notable projects and estimated expenditures for the year.

		Calendar 2006 (in millions)
Expansion Capital		
St. James, Louisiana storage facility Phase I	$	72
St. James, Louisiana storage facility Phase II		12
Kerrobert tankage		31
East Texas/Louisiana tankage		17
Spraberry System expansion		15
Cushing Tankage Phase VI		14
High Prairie rail terminals		13
Midale/Regina truck terminal		13
Truck trailers		9
Wichita Falls tankage		8
Basin connection Oklahoma		8
Mobile/ Ten Mile tankage and metering		6
Other Projects		92
		310
Maintenance Capital		21
Total Projected Capital Expenditures (excluding acquisitions)	$	331

7. *Capital Structure.* This guidance is based on our capital structure as of September 30, 2006 as adjusted to give effect to the aggregate $1 billion private placement of 10-year and 30-year senior notes (New Senior Notes) that closed on October 30, 2006. The net proceeds from the New Senior Notes will be used to fund the cash portion of the Pacific Energy acquisition expected to close in the fourth quarter of 2006. Pending closing of the Pacific Energy merger, we intend to invest excess proceeds that are not used to repay outstanding indebtedness or for general partnership purposes in short-term investments. In the event the Pacific Energy acquisition does not close by February 15, 2007, we are required to call the New Senior Notes at 101% of the principal amount. See Note 8 for treatment of interest expense and interest income attributable to the New Senior Notes during the fourth quarter.

   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.

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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 three months ending December 31, 2006 is expected to be between $19.3 million and $20.1 million, assuming an average long-term debt balance excluding the New Senior Notes 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 September 30, 2006, 100% of our long-term debt balance was fixed at an average interest rate of 6.1%. 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.

   The amount of interest expense noted in the preceding paragraph excludes approximately $10.8 million of interest expense associated with the New Senior Notes discussed in Note 7 above, as well as approximately $8.7 million of interest income earned from investing the net proceeds from the notes offering pending closing of the Pacific Energy acquisition. These amounts are included as separate line items in our primary guidance table, but have been treated as Selected Items Impacting Comparability in arriving at Adjusted EBITDA and Adjusted Net Income. We believe this is consistent with our treatment of excluding any contribution from Pacific Energy in our guidance pending the closing of the acquisition. In the event the Pacific Energy acquisition does not close by February 15, 2007, we are required to call the New Senior Notes at 101% of the principal amount. See Note 12 for an estimate on Adjusted EBITDA and Adjusted Net Income of the impact of the Pacific Energy acquisition assuming the acquisition closes on November 15, 2006.

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.

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	Guidance (in millions, except per unit data)			
	Three Months Ending December 31, 2006		Twelve Months Ending December 31, 2006	
	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:				
Net Income	$ 56.4	$ 67.6	$ 295.5	$ 306.7
Less:				
General partner s incentive distribution	(11.1)	(11.1)	(33.1)	(33.1)
	45.3	56.5	262.4	273.6
General partner 2% ownership	(0.9)	(1.1)	(5.3)	(5.5)
Net income available to limited partners	44.4	55.4	257.1	268.1
Pro forma additional general partner s distribution			(16.1)	(21.5)
Net Income available for limited partners under EITF 03-06	$ 44.4	$ 55.4	$ 241.0	$ 246.6
Denominator:				
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	81.0	81.0	78.0	78.0
Effect of dilutive securities:				
Weighted average LTIP units	1.0	1.0	0.8	0.8
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	82.0	82.0	78.8	78.8
Basic net income per limited partner unit	$ 0.55	$ 0.68	$ 3.09	$ 3.16
Diluted net income per limited partner unit	$ 0.54	$ 0.67	$ 3.06	$ 3.13

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 $3.00 per unit, our general partner s distribution is forecast to be approximately $49.3 million annually, of which $44.3 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 $3.00 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*. The majority of grants outstanding under our Long-Term Incentive Plans contain vesting criteria that are based on a combination of performance benchmarks and service period. The grants will vest in various percentages, typically on the later to occur of specified earliest vesting dates and the dates on

which minimum distribution levels are reached. Among the various grants, vesting dates range from May 2007 to December 2010 and minimum annualized distribution levels range from $2.60 to $4.00. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012.

We have reached the annualized distribution level of $3.00 and it has been deemed probable that the $3.20 distribution level will be achieved. Accordingly, guidance includes, for grants that vest at annualized distribution levels of $3.20 or less, an accrual over the corresponding service period at an assumed market price of $46.15 per unit as well as the fair value associated with awards that will vest on a date certain. For 2006, the guidance includes approximately $36.5 million of principally non-cash expense associated with these grants. The earliest significant vesting event for outstanding grants will occur in May 2007.

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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.

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.

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 December 31, 2006		Twelve Months Ending December 31, 2006	
	Low	High	Low	High
	(in millions)			
Reconciliation to Net Income				
EBITDA	$ 105.6	$ 115.6	$ 464.3	$ 474.3
Depreciation and amortization	27.0	26.6	94.1	93.7
EBIT	78.6	89.0	370.2	380.6
Interest expense existing notes and facilities	20.1	19.3	72.6	71.8
Interest expense New Senior Notes, net	2.1	2.1	2.1	2.1
Net Income	$ 56.4	$ 67.6	$ 295.5	$ 306.7

12. *Combined Plains and Pacific Energy Guidance.* Plains and Pacific Energy will each hold their respective unitholder meetings on November 9, 2006 seeking approval of the proposed merger between Plains and Pacific Energy. The following table presents adjusted EBITDA and adjusted net income for the combined entities assuming the proposed merger is approved and closing occurs on November 15, 2006. The Pacific Energy information is derived from Pacific Energy s guidance contained in its press release dated November 1, 2006, however, it excludes the impact of anticipated transaction synergies and contributions from capital expansion projects under construction. Although we have not reviewed Pacific Energy s calculation of its guidance ranges, we believe that the estimates are reasonable.

	For the Three Months Ending December 31, 2006		
	Plains	Pacific Energy	Combined Guidance
	(midpoint of guidance amounts; in millions)		
Adjusted EBITDA	$ 120.0	$ 18.5[1]	$ 138.5
Interest Expense	(19.7)	(11.2)[2]	(30.9)
Depreciation and amortization	(26.8)	(5.6)[3]	(32.4)
Adjusted Net Income	$ 73.5	$ 1.7	$ 75.2
Basic Units Outstanding	81.0	11.1	92.1
Diluted Units Outstanding	82.0	11.1	93.1

Adjusted Basic Net Income per Limited Partner Unit	$ 0.76	$ 0.67
Adjusted Diluted Net Income per Limited Partner Unit	$ 0.75	$ 0.66

[1] Per Pacific Energy mid-point estimate of $36.9 million reported in its press release dated November 1, 2006 and prorated based on an assumed closing date of November 15, 2006. Excludes the impact of anticipated transaction synergies and contributions from capital expansion projects under construction.

[2] As computed by PAA based on debt assumed from Pacific Energy and estimated cash paid on an assumed closing date of November 15, 2006. Such interest expense includes a forecast of interest incurred on the New Senior Notes from November 15, 2006 through the remainder of

the year, but does not include interest expense on the New Senior Notes or interest income from investment of the proceeds for the period prior to November 15, 2006.

[3] PAA estimate of depreciation and amortization on the acquired assets based on the straight-line method of depreciation over average useful lives ranging from 5 to 40 years. Depreciation and amortization estimates are based on estimated purchase price allocations assumptions used in PAA's Current Report on Form 8-K filed on August 24, 2006.

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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, inter 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:

our failure to successfully integrate the respective business operations upon completion of the merger with Pacific Energy or our failure to successfully integrate any future acquisitions;

the failure to realize the anticipated cost savings, synergies and other benefits of the proposed merger with Pacific Energy;

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 main 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 tariffs or volumes on 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;

- risks related to the development and operation of natural gas storage facilities;

- 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.

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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: November 2, 2006

By: /s/ Phil Kramer

Name: Phil Kramer
Title: *Executive Vice President and Chief Financial Officer*

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Exhibit Index

Exhibit No.	Description of Exhibit
99.1	Press release dated November 2, 2006