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 1, 2007

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 1, 2007

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 2007 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 of calendar 2007 and resulting financial performance for the full year of calendar 2007 (which supersedes guidance in our Form 8-K furnished on August 6, 2007) and are providing preliminary guidance for calendar 2008. 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 2007 Guidance; Disclosure of Full Year 2008 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 10 below, we reconcile EBITDA and EBIT to net income for the 2007 guidance periods presented. It is, however, 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 equity compensation plans and, to the extent known, gains and losses related to SFAS 133 (primarily non-cash, mark-to-market adjustments) on Segment Profit, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three-month and the twelve-month periods ending December 31, 2007, as well as the preliminary guidance for calendar 2008, is based on assumptions and estimates that we believe are reasonable given our assessment of historical trends (modified for recent changes in market conditions), business cycles and other information reasonably available. Our assumptions and future performance, however, 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, 2007. 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	Guidance (1)(2)			
	Nine Months Ended 09/30/07	Three Months Ending December 31, 2007		Twelve Months Ending December 31, 2007	
		Low	High	Low	High
Segment Profit					
Net revenues (including equity earnings in unconsolidated entities)	$ 1,074.3	$ 326.8	$ 344.3	$ 1,401.1	$ 1,418.6
Field operating costs	(394.8)	(133.7)	(131.7)	(528.5)	(526.5)
General and administrative expenses	(127.9)	(37.7)	(37.2)	(165.6)	(165.1)
	551.6	155.4	175.4	707.0	727.0
Depreciation and amortization expense	(134.9)	(44.0)	(42.0)	(178.9)	(176.9)
Interest expense, net	(121.1)	(42.0)	(40.0)	(163.1)	(161.1)
Income tax expense	(15.4)	(0.8)	(0.5)	(16.2)	(15.9)
Other income (expense), net	7.7	12.0	12.0	19.7	19.7
Net Income	**$ 287.9**	**$ 80.6**	**$ 104.9**	**$ 368.5**	**$ 392.8**
Net Income to Limited Partners	$ 231.3	$ 58.3	$ 82.1	$ 289.6	$ 313.4
Basic Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	112.1	116.0	116.0	113.0	113.0
Net Income Per Unit	$ 2.06	$ 0.50	$ 0.71	$ 2.56	$ 2.77
Diluted Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	113.0	116.8	116.8	113.9	113.9
Net Income Per Unit	$ 2.05	$ 0.50	$ 0.70	$ 2.54	$ 2.75
EBIT	**$ 424.4**	**$ 123.4**	**$ 145.4**	**$ 547.8**	**$ 569.8**
EBITDA	**$ 559.3**	**$ 167.4**	**$ 187.4**	**$ 726.7**	**$ 746.7**
Selected Items Impacting Comparability					
Equity compensation charge	$ (37.9)	$ (9.4)	$ (9.4)	$ (47.3)	$ (47.3)
Gain on sale of pipeline linefill (3)	—	12.0	12.0	12.0	12.0
Deferred income tax expense (4)	(10.8)	—	—	(10.8)	(10.8)
SFAS 133 Mark-to-Market Adjustment	(14.8)	—	—	(14.8)	(14.8)
	$ (63.5)	$ 2.6	$ 2.6	$ (60.9)	$ (60.9)
Excluding Selected Items Impacting Comparability					
Adjusted Segment Profit					
Transportation	$ 263.7	$ 90.0	$ 95.0	$ 353.7	$ 358.7
Facilities	84.6	29.0	32.0	113.6	116.6
Marketing	257.7	46.0	58.0	303.7	315.7
Other Income (Expense), net	6.0	—	—	6.0	6.0
Adjusted EBITDA (5)	$ 612.0	$ 165.0	$ 185.0	$ 777.0	$ 797.0
Adjusted Net Income	$ 351.4	$ 78.0	$ 102.3	$ 429.4	$ 453.7
Adjusted Basic Net Income per Limited Partner Unit	$ 2.62	$ 0.48	$ 0.69	$ 3.10	$ 3.30
Adjusted Diluted Net Income per Limited Partner Unit	$ 2.60	$ 0.48	$ 0.68	$ 3.09	$ 3.29

(1) The projected average foreign exchange rate is $1.00 CAD to $1 USD. The rate as of October 31, 2007 was $0.94 CAD to $1 USD.

(2) The sum of the interim periods may not equal the total year due to rounding.

(3) In the fourth quarter of 2007, we sold 250,000 barrels of pipeline linefill in owned assets for a gain of approximately $12 million. These volumes represent a change in the estimate of the amount of linefill required on certain of our assets. Linefill and minimum working inventory requirements in assets we own are recorded at historical cost.

(4) Amount related to the initial cumulative effect of the recent change in Canadian tax legislation.

(5) Excludes deferred income tax expenses included in the list of selected items impacting comparability.

Notes and Significant Assumptions:

1. *Definitions.*

Bcf	Billion cubic feet
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 (including equity earnings, as applicable) less purchases, field operating costs, and segment general and administrative expenses
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other petroleum products
FX	Foreign currency exchange

2. *Business Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. The following is a brief explanation of the operating activities for each segment as well as key metrics.

   a. *Transportation.* Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, trucks and gathering systems. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. We also include in this segment our equity earnings from our investments in the Butte and Frontier pipeline systems, in which we own minority interests, and Settoon Towing, in which we own a 50% interest.

   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. Segment profit is forecast using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level of volumes transported or expenses incurred during the period.

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

	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	48	48	48
Basin	382	360	375
Capline	232	230	232
Line 63 / 2000	177	180	179
Salt Lake City	62	63	62
N. Dakota / Trenton	95	100	96
West Texas / New Mexico (1)	391	380	387
Manito	74	75	75
Refined Products	110	110	109
Other	1,125	1,154	1,133
	2,696	2,700	2,696
Trucking	107	115	111
	2,803	2,815	2,807
Average Segment Profit ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.34	$ 0.36(2)	$ 0.35(2)

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

(2) Mid-point of guidance.

b. *Facilities*. Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. This segment also includes our equity earnings from our 50% investment in PAA/Vulcan Gas Storage, LLC which owns and operates approximately 25.7 billion cubic feet of underground natural gas storage capacity and is constructing an additional 24 Bcf of underground storage capacity.

Segment profit is forecast using the volume assumptions in the table below, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

	Actual	Guidance	
	Nine Months Ended September 30	Three Months Ending December 31	Twelve Months Ending December 31
Operating Data			
Crude oil, refined products and LPG storage (MMBbls/Mo.)	36.9	41.0	37.9
Natural Gas Storage (Bcf/Mo.)	12.9	12.9	12.9
LPG Processing (MBbl/d)	18.2	20.7	18.8
Facilities Activities Total (1)			
Avg. Capacity (MMBbls/Mo.)	39.6	43.8	40.6
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.24	$ 0.23(2)	$ 0.24(2)

(1) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly capacity in millions.

(2) Mid-point of guidance.

c. *Marketing*. Our marketing segment operations generally consist of the following merchant activities:

- the purchase of crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers; and
- the arrangement of the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

The level of profit in the marketing segment is influenced by overall market structure and the degree of volatility in the crude oil market as well as variable operating expenses. Forecasted operating results for the three-month period ending December 31, 2007 reflect our expectation of a less favorable market than experienced in the first nine months of 2007. Unexpected changes in market structure or volatility (or lack thereof) could cause actual results to differ materially from forecasted results.

We forecast segment profit using the volume assumptions stated below 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.

	Actual	Guidance	
	Nine Months Ended September 30	Three Months Ending December 31	Twelve Months Ending December 31
Average Daily Volumes (MBbl/d)			
Crude Oil Lease Gathering	689	680	687
LPG Sales	78	105	85
Refined Products	10	15	11
Waterborne foreign crude imported	76	60	72
	853	860	855
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 1.11	$ 0.66(1)	$ 0.99(1)

(1) Mid-point of guidance.

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, forecasted capital expenditures and projected in-service dates. 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) and includes gains and losses on the sale of assets.

4. *Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133")* . The guidance presented above does not include forecasts 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.

5. *Capital Expenditures and Acquisitions*. Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions that may be made after the date hereof. Capital expenditures for expansion projects are forecasted to be approximately $540 million during calendar 2007, of which $392 was incurred in the first nine months. Following are some of the more notable projects and forecasted expenditures for the year:

	Calendar 2007 (in millions)
Expansion Capital	
• St. James, Louisiana Storage Facility	$ 80
• Cheyenne Pipeline	68
• Salt Lake City Expansion	55
• Cushing Tankage — Phase VI	34
• Patoka Tankage	32
• Martinez Terminal	25
• Fort Laramie Tank Expansion	21
• High Prairie Rail Terminal	12
• Paulsboro Expansion	8
• Elk City to Calumet	12
• Pier 400	7
• Kerrobert Tankage	9
• Other Projects*	177
	540
Maintenance Capital	48
Total Projected Capital Expenditures (excluding acquisitions)	$ 588

* Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

Capital expenditures for maintenance projects are forecast to be approximately $48 million during 2007, of which $32 million was incurred in the first nine months.

6. *Capital Structure*. This guidance is based on our capital structure as of September 30, 2007. 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. As a result of our recent equity financing activities in combination with our projected 2007 cash flows in excess of distributions, we have pre-funded the required equity financing associated with our 2007 expansion capital program, as well as a large portion, if not all, of our 2008 expansion capital program.

7. *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.

   Annual 2007 interest expense is expected to be between $161 million and $163 million, assuming an average long-term debt balance of approximately $2.6 billion during the period. Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, 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 IntercontinentalExchange margin deposits). Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for contango inventory. We treat interest on contango related borrowings as carrying costs of crude oil and include it as part of the purchase price of crude oil.

8. *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.

	Actual	Guidance			
	Nine Months Ended	Three Months Ending December 31, 2007		Twelve Months Ending December 31, 2007	
	09/30/07	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:					
Net Income	$ 287.9	$ 80.6	$ 104.9	$ 368.5	$ 392.8
General partners incentive distribution	(66.9)	(26.1)	(26.1)	(93.0)	(93.0)
General partners incentive distribution reduction	15.0	5.0	5.0	20.0	20.0
	236.0	59.5	83.8	295.5	319.8
General partner 2% ownership	(4.7)	(1.2)	(1.7)	(5.9)	(6.4)
Net income available to limited partners	$ 231.3	$ 58.3	$ 82.1	$ 289.6	$ 313.4
Denominator:					
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	112.1	116.0	116.0	113.0	113.0
Effect of dilutive securities:					
Weighted average LTIP units	0.9	0.8	0.8	0.9	0.9
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	113.0	116.8	116.8	113.9	113.9
Basic net income per limited partner unit	$ 2.06	$ 0.50	$ 0.71	$ 2.56	$ 2.77
Diluted net income per limited partner unit	$ 2.05	$ 0.50	$ 0.70	$ 2.54	$ 2.75

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 partner interests is 98% of the total partnership income after deducting the amount of the general partner's incentive distribution. Based on our current annualized distribution rate of $3.36 per unit, our general partner's distribution is forecast to be approximately $112.3 million annually, of which approximately $104.4 million is attributed to the incentive distribution rights. In conjunction with the Pacific acquisition, however, the general partner agreed to reduce the amounts due it as incentive distributions. The reduction will be effective for five years, as follows: (i) $5 million per quarter for the first four quarters beginning with the February 2007 distribution, (ii) $3.75 million per quarter for the following eight quarters, (iii) $2.5 million per quarter for the following four quarters, and (iv) $1.25 million per quarter for the final four quarters. The total reduction in incentive distributions will be $65 million. Total incentive distributions to the general partner in 2007 will be reduced by $20.0 million. The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Each $0.05 per unit annual increase in the distribution over $3.36 per unit decreases net income available for limited partners by approximately $5.8 million ($0.05 per unit) on an annualized basis.

9. *Equity Compensation 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 2008 to May 2012 and minimum annualized distribution levels range from $2.80 to $4.00. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012.

On October 18, 2007, we declared an annualized distribution of $3.36 payable on November 14, 2007 to our unitholders of record as of November 2, 2007. In addition to achieving the distribution level of $3.36, we have deemed probable that the $3.50 distribution level will be achieved. Accordingly, for grants that vest at annualized distribution levels of $3.50 or less, guidance includes an accrual over the corresponding service period at an assumed market price of $56.00 per unit as well as the fair value associated with awards that will vest on a date certain. For 2007, the guidance includes approximately $50.4 million of expense associated with these LTIP grants. The actual amount of equity compensation expense amortization in any given year will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the date of actual vesting, (iii) the amount of amortization in the early years, and (iv) new LTIP award grants. For example, a $3.00 change in the unit price assumption at December 31, 2007 would change the total amortization by $3.1 million — $0.4 million for the current quarter and $2.7 million for the life-to-date adjustment to the liability accrued in prior periods. Therefore, actual net income could differ materially from our projections.

On August 29, 2007, the Board of Directors of Plains All American GP LLC authorized the grant of 200,000 Class B units in Plains AAP, L.P., our general partner. At September 30, 2007, approximately 85,500 Class B units have been granted and the remaining units are reserved for future grants. The Class B units are earned in 25% increments upon us achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50. When earned, the Class B units are entitled to participate in distributions paid to our general partner in any quarter in which we distribute at least $0.875 per common unit ($3.50 per common unit on an annualized basis). Assuming all 200,000 Class B units were granted and earned, the maximum participation would be 8% of the general partner distribution in excess of $11.0 million each quarter. Although the Class B units, which are equity classified, do not impact our cash or units outstanding, the intent of the Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. Based on our assessment that achievement of the $3.50 annualized distribution level is probable, we have included approximately $2.0 million of compensation expense attributable to the Class B units in the guidance for 2007. The expense is reflected as a selected item impacting comparability since the economic burden is borne solely by the General Partner and not the Partnership. The expense will be reflected as a capital contribution and thus will result in a corresponding credit to the general partners' capital in the financial statements of the Partnership.

The amount of equity compensation expense highlighted in selected items impacting comparability for 2007 excludes the portion of the equity compensation expense represented by LTIP grants under the 2006 Plan that, pursuant to the terms of the Plan, will be settled in cash only ($5.1 million) and have no impact in the determination of diluted units.

10. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the 2007 guidance ranges for EBITDA and EBIT to net income.

	Three Months Ending December 31, 2007		Twelve Months Ending December 31, 2007	
	Low	High	Low	High
Reconciliation to Net Income				
EBITDA	$ 167.4	$ 187.4	$ 726.7	$ 746.7
Depreciation and amortization	44.0	42.0	178.9	176.9
EBIT	123.4	145.4	547.8	569.8
Interest expense	42.0	40.0	163.1	161.1
Income tax expense	0.8	0.5	16.2	15.9
Net Income	$ 80.6	$ 104.9	$ 368.5	$ 392.8

Preliminary Calendar 2008 Guidance

This preliminary adjusted EBITDA guidance for 2008 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, (3) contributions from expansion capital expenditures in line with our expectations, and (4) a less favorable market relative to our assets and business model than experienced in the first nine months of 2007. The following table summarizes the range of selected key financial data of our preliminary projections for calendar year 2008.

Preliminary Calendar 2008 Guidance (in millions)

	Low	High
Adjusted EBITDA	$ 760	$ 810
Depreciation and amortization	(193)	(183)
Interest expense	(177)	(167)
Adjusted Net Income	$ 390	$ 460
Maintenance Capital Expenditures	$ 60	$ 55

Our preliminary guidance for interest expense is based on our projected capital structure as of September 30, 2007, the current market outlook for floating interest rates and our current forecast of approved capital projects for 2008. Our preliminary guidance for depreciation and amortization is based on projected depreciation from our present asset base, and continued development of our portfolio projects. Our preliminary guidance for maintenance capital expenditures is based on our estimated level of recurring expenditures of approximately $55 to $60 million. Adjusted net income and adjusted EBITDA exclude selected items impacting comparability such as equity compensation expense and SFAS 133. 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. The absence of these words, however, 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 failure to realize the anticipated synergies and other benefits of the merger with Pacific Energy Partners;
- 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 systems;
- failure to implement or capitalize on planned internal growth projects;
- shortages or cost increases of power supplies, materials or labor;
- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transmission throughput requirements;
- 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;
- 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 transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

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: November 1, 2007

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

Index to Exhibits

Exhibit 99.1—Press release dated November 1, 2007

Exhibit 99.1

PLAINS ALL AMERICAN PIPELINE, L.P.

News Release

Contacts:

Phil D. Kramer
Executive Vice President and CFO
713/646-4560 — 800/564-3036

Roy I. Lamoreaux
Manager, Investor Relations
713/646-4222 — 800/564-3036

FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports Third-Quarter 2007 Results

(Houston — November 1, 2007) Plains All American Pipeline, L.P. (NYSE: PAA) today reported third-quarter 2007 net income of $98.4 million, or $0.66 per diluted limited partner unit, compared to third-quarter 2006 net income of $95.4 million, or $0.89 per diluted limited partner unit. For the first nine months of 2007, the Partnership reported net income of $287.9 million, or $2.05 per diluted limited partner unit, compared to net income of $239.1 million, or $2.43 per diluted limited partner unit, for the first nine months of 2006. The Partnership's basic weighted average units outstanding for the third quarter of 2007 totaled 116.0 million (116.8 million diluted) compared to 79.9 million (80.8 million diluted) for the third quarter of 2006.

The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") for the third quarter of 2007 of $183.3 million, an increase of 32% compared with EBITDA of $138.8 million for the third quarter of 2006. EBITDA for the first nine months of 2007 was $559.3 million, an increase of 56% compared with EBITDA of $358.7 million for the first nine months of 2006. (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.)

"We are pleased with our solid third-quarter operating and financial results," stated Greg L. Armstrong, Chairman and CEO of Plains All American. "The Partnership ended the quarter with a strong balance sheet and excellent liquidity and is well positioned to finance its ongoing organic growth activities as well as capitalize on attractive acquisition opportunities. While the Partnership invested approximately $460 million on expansion projects and acquisitions during the first nine months of the year, long-term debt remained unchanged. Additionally, as a result of our recent equity offering and the liquidation of a portion of our contango inventory, short-term debt has decreased more than $500 million since the beginning of the year."

Armstrong also stated that the Partnership increased the midpoint of its full-year operating and financial guidance, which takes into account the third-quarter shift in the overall crude oil market structure. In addition, the midpoint of the Partnership's preliminary adjusted EBITDA baseline guidance for 2008 is approximately 14% higher than the initial baseline guidance for 2007 provided in February.

Reported results include the impact of various items that affect comparability between reporting periods. Adjusted results exclude selected items impacting comparability, as further described in the table below. After excluding such items, the Partnership's third-quarter 2007 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $111.5 million, $0.77 and $196.4 million, respectively. Comparable results for the third quarter of 2006 were $87.8 million, $0.95 and $131.2 million, respectively. Adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first nine months of 2007 were $351.4 million, $2.60 and $612.0 million, respectively, compared to $245.1 million, $2.81 and $364.7 million, respectively, for the first nine months of 2006.

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(In millions, except per unit data)			
Selected items impacting comparability				
Equity compensation charge(1)	$ (0.5)	$ (10.3)	$ (37.9)	$ (27.1)
Cumulative effect of change in accounting principle — Equity Compensation(2)	—	—	—	6.3
SFAS 133 mark-to-market adjustment(3)	(12.6)	17.9	(14.8)	14.8
Deferred income tax expense(4)	—	—	(10.8)	—
Selected items impacting comparability	(13.1)	7.6	(63.5)	(6.0)
Less: GP 2% portion of selected items impacting comparability	0.3	(0.2)	1.3	0.1
LP 98% portion of selected items impacting comparability	$ (12.8)	$ 7.4	$ (62.2)	$ (5.9)
Impact to basic net income per limited partner unit(5)	$ (0.11)	$ (0.06)	$ (0.56)	$ (0.39)
Impact to diluted net income per limited partner unit(5)	$ (0.11)	$ (0.06)	$ (0.55)	$ (0.38)

(1) The equity compensation charge for the three- and nine-month periods ended September 30, 2007 excludes the portion of the equity compensation expense represented by grants under the 2006 Plan that, pursuant to the terms of the Plan, will be settled in cash only and have no impact on diluted units.

(2) During the first quarter of 2006, we adopted SFAS No. 123(R) “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 adjustment decreased our equity compensation 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.

(3) The SFAS No. 133 “Accounting for Derivative Instruments and Hedging Activities”, as amended (“SFAS 133”) charge for the three- and nine-month periods ended September 30, 2007, includes a $2.0 million gain and $1.7 million gain, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net but does not impact segment profit.

(4) Includes the initial cumulative effect of the recent change in Canadian tax legislation.

(5) In periods when the Partnership’s net income exceeds the cash distribution paid during such periods, 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”) 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 $0.16 for the three months ended September 30, 2006 and $0.31 for the nine months ended September 30, 2006. The application of EITF 03-06 had no impact for the three and nine months ended September 30, 2007.

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The following tables present certain selected financial information by segment for the third quarter reporting periods:

	Three Months Ended September 30, 2007			Three Months Ended September 30, 2006		
	Transportation Operations	Facilities Operations	Marketing Operations	Transportation Operations	Facilities Operations	Marketing Operations
		(In millions)			(In millions)	
Revenues(1)	$ 198.1	$ 54.0	$ 5,668.0	$ 134.9	$ 21.3	$ 4,430.4
Purchases and related costs(1)	(19.7)	—	(5,555.9)	(17.8)	—	(4,304.8)
Field operating costs (excluding equity compensation (charge)/credit)	(73.8)	(22.1)	(38.3)	(48.2)	(9.5)	(35.2)
Equity compensation (charge)/credit — operations	0.1	—	—	(1.1)	—	—
Segment G&A expenses (excluding equity compensation charge)(2)	(13.9)	(5.2)	(13.2)	(10.8)	(2.8)	(10.2)
Equity compensation charge — general and administrative	(0.5)	(0.3)	(0.3)	(3.9)	(1.3)	(4.0)
Equity earnings in unconsolidated entities	1.5	2.3	—	0.2	1.3	—
Segment profit	$ 91.8	$ 28.7	$ 60.3	$ 53.3	$ 9.0	$ 76.2
SFAS 133 mark-to-market impact(3)	$ —	$ —	$ (14.6)	$ —	$ —	$ 17.9
Maintenance capital	$ 9.2	$ 0.2	$ 0.5	$ 5.3	$ 1.9	$ 1.0

	Nine Months Ended September 30, 2007			Nine Months Ended September 30, 2006		
	Transportation Operations	Facilities Operations	Marketing Operations	Transportation Operations	Facilities Operations	Marketing Operations
		(In millions)			(In millions)	
Revenues(1)	$ 570.5	$ 153.3	$ 13,565.1	$ 383.7	$ 54.6	$ 17,788.1
Purchases and related costs(1)	(57.7)	—	(13,168.6)	(54.6)	—	(17,462.5)
Field operating costs (excluding equity compensation (charge)/credit)	(213.4)	(62.3)	(114.9)	(141.9)	(23.9)	(99.9)
Equity compensation (charge)/credit — operations	(4.5)	(0.1)	(0.3)	(2.8)	—	(0.1)
Segment G&A expenses (excluding equity compensation charge)(2)	(37.7)	(14.7)	(39.0)	(30.2)	(9.8)	(28.0)
Equity compensation charge — general and administrative	(16.2)	(5.5)	(14.8)	(10.4)	(3.5)	(10.3)
Equity earnings in unconsolidated entities	3.6	8.8	—	1.0	2.2	—
Segment profit	$ 244.6	$ 79.5	$ 227.5	$ 144.8	$ 19.6	$ 187.3
SFAS 133 mark-to-market impact(3)	$ —	$ —	$ (16.5)	$ —	$ —	$ 14.8
Maintenance capital	$ 21.6	$ 6.4	$ 3.6	$ 11.7	$ 3.4	$ 2.2

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(1) Includes intersegment amounts. Effective April 1, 2006, we adopted EITF 04-13, which impacts the comparability of our revenues and purchases. Revenues and purchases for the nine months ended September 30, 2006 include buy/sell transactions of $4.8 billion. Revenues and purchases from such transactions are excluded from the nine-month period ended September 30, 2007.

(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 judgement 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. The SFAS 133 amount for the three- and nine-month periods ended September 30, 2007 excludes a $2.0 million gain and $1.7 million gain, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net but does not impact segment profit.

Excluding selected items impacting comparability, third-quarter 2007 adjusted segment profit from Transportation operations was $92.0 million, 58% higher than third-quarter 2006 adjusted segment results of $58.3 million. Transportation volumes for the third quarter of 2007 were 2.8 million barrels per day versus 2.2 million barrels per day in the third quarter of 2006.

Third-quarter 2007 adjusted segment profit for Facilities operations was $28.9 million representing a 181% increase over third-quarter 2006 adjusted Facilities operations segment profit of $10.3 million, reflecting increased storage capacity and throughput activity due to the Pacific acquisition and the completion of new capital projects.

Marketing operations adjusted segment profit of $75.0 million for the third quarter of 2007 represents an increase of 20% over the third-quarter 2006 adjusted results of $62.3 million reflecting an expanded asset base, improved margins in our lease gathering activities and the carryover effect of favorable market conditions experienced during the first half of 2007.

The Partnership's basic weighted average units outstanding for the third quarter of 2007 totaled 116.0 million (116.8 million diluted) as compared to 79.9 million (80.8 million diluted) in last year's third quarter. At September 30, 2007, the Partnership had 116.0 million units outstanding, long-term debt of $2.6 billion and a long-term debt-to-total capitalization percentage of 43%.

On October 18, 2007, the Partnership declared a cash distribution of $0.84 per unit ($3.36 per unit on an annualized basis) on its outstanding limited partner units. The distribution payable on November 14, 2007 represents an increase of 12.0% over the distribution paid in November 2006 and 1.2% over the distribution paid in August 2007. November's distribution represents the fourteenth consecutive increase in quarterly distributions for the Partnership and the twenty-first increase in the last twenty-seven quarters.

The Partnership will furnish a current report on Form 8-K, which will include material in this press release and financial and operational guidance fourth quarter and full year 2007 as well as preliminary 2008 financial guidance. A copy of the Form 8-K will be 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 net income or cash flows from 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

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periods presented. Variations in our operating results are also caused by changes in volumes, prices and exchange rates, as well as 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 flows 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 tab.

Conference Call

The Partnership will host a conference call on Friday, November 2, 2007 to discuss the following items:

1. The Partnership's third-quarter 2007 performance;

2. Status of major expansion capital projects and recent acquisition activity;

3. Capitalization and liquidity;

4. Financial and operating guidance for the fourth quarter and full year 2007, and preliminary 2008 guidance; and

5. 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. You may access the slide presentation accompanying the conference call a few minutes prior to the call under the Conference Call Summaries portion of the Conference Calls tab of the Investor Relations section of our website at www.paalp.com.

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." The call will be archived on the Partnership's website for a period of sixty (60) days following the live webcast.

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 account number 232 and replay number 258001. The replay will be available beginning Friday, November 2, 2007, at approximately 1:00 PM (Eastern) and continue until 11:59 PM (Eastern) Friday, November 30, 2007.

Plains All American Pipeline, L.P. is a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. 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 is headquartered in Houston, Texas.

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

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things: the failure to realize the anticipated synergies and other benefits of the 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 systems; failure to implement or capitalize on planned internal growth projects; shortages or cost increases of power supplies, materials or labor; the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third party shippers; fluctuations in refinery capacity in areas supplied by our mainlines, and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transmission throughput requirements; 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; 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 transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products discussed in the Partnership's filings with the Securities and Exchange Commission.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONSOLIDATED STATEMENTS OF OPERATIONS

(In millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
REVENUES(1)	$5,799.0	$4,525.5	$13,946.3	$18,052.6
COSTS AND EXPENSES				
Purchases and related costs(1)	5,455.2	4,261.5	12,884.4	17,343.3
Field operating costs	133.4	94.0	394.8	268.6
General and administrative expenses	33.4	33.0	127.9	92.2
Depreciation and amortization	42.9	24.2	134.9	67.1
Total costs and expenses	5,664.9	4,412.7	13,542.0	17,771.2
OPERATING INCOME	134.1	112.8	404.3	281.4
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	3.8	1.5	12.4	3.2
Interest expense	(38.8)	(19.2)	(121.1)	(52.5)
Interest income and other income (expense), net	2.5	0.3	7.7	0.7
Income before tax	101.6	95.4	303.3	232.8
Current income tax expense	(0.4)	—	(1.3)	—
Deferred income tax expense	(2.8)	—	(14.1)	—
Income before cumulative effect of change in accounting principle	98.4	95.4	287.9	232.8
Cumulative effect of change in accounting principle	—	—	—	6.3
NET INCOME	$ 98.4	$ 95.4	$ 287.9	$ 239.1
NET INCOME — LIMITED PARTNERS	$ 76.8	$ 84.6	$ 231.3	$ 212.7
NET INCOME — GENERAL PARTNER	$ 21.6	$ 10.8	$ 56.6	$ 26.4
BASIC NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.66	$ 0.90	$ 2.06	$ 2.37
Cumulative effect of change in accounting principle	—	—	—	0.08
Basic net income per limited partner unit	$ 0.66	$ 0.90	$ 2.06	$ 2.45
DILUTED NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.66	$ 0.89	$ 2.05	$ 2.35
Cumulative effect of change in accounting principle	—	—	—	0.08
Diluted net income per limited partner unit	$ 0.66	$ 0.89	$ 2.05	$ 2.43
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	116.0	79.9	112.1	77.0
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	116.8	80.8	113.0	77.8

(1) Revenues and purchases include buy/sell transactions of $4.8 billion in the three months ended March 31, 2006.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

OPERATING DATA(1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Transportation activities (Average Daily Volumes, thousands of barrels):				
Tariff activities				
All American	46	50	48	49
Basin	397	324	382	323
Capline	230	183	232	149
Line 63/Line 2000	171	N/A	177	N/A
Salt Lake City	59	N/A	62	N/A
North Dakota/Trenton	93	94	95	88
West Texas/New Mexico area systems(2)	409	416	391	445
Manito	72	73	74	70
Refined products	110	15	110	5
Other	1,118	977	1,125	855
	2,705	2,132	2,696	1,984
Trucking volumes	104	103	107	111
Transportation activities total	2,809	2,235	2,803	2,095
Facilities activities (Average Monthly Volumes):				
Crude oil, refined products, and LPG storage (average monthly capacity in millions of barrels)	39.6	18.8	36.9	18.8
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	12.9	12.9	12.4
LPG processing (thousands of barrels per day)	20.8	16.3	18.2	11.5
Facilities activities total (average monthly capacity in millions of barrels)(3)	42.4	21.4	39.6	21.2
Marketing activities (Average Daily Volumes, thousands of barrels):				
Crude oil lease gathering	679	650	689	639
Refined products	14	N/A	10	N/A
LPG sales	58	39	78	49
Waterborne foreign crude imported	82	80	76	59
Marketing activities total	833	769	853	747

(1) Volumes associated with acquisitions represent total volumes 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.

(3) In order to calculate total facilities activities volume add: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by 1,000 and the number of months in the period to convert to monthly capacity in millions.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(In millions)

	September 30, 2007	December 31, 2006
ASSETS		
Current assets	$ 3,184.6	$ 3,157.6
Property and equipment, net	4,272.7	3,842.0
Pipeline linefill in owned assets	240.5	265.5
Inventory in third-party assets	63.0	75.7
Investment in unconsolidated entities	212.9	183.0
Goodwill	1,059.2	1,026.2
Other long-term assets, net	154.3	164.9
Total assets	$ 9,187.2	$ 8,714.9
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 3,020.1	$ 3,024.7
Long-term debt under credit facilities and other	1.2	3.1
Senior notes, net of unamortized discount	2,623.0	2,623.2
Other long-term liabilities and deferred credits	119.7	87.1
Total liabilities	5,764.0	5,738.1
Partners' capital	3,423.2	2,976.8
Total liabilities and partners' capital	$ 9,187.2	$ 8,714.9

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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 September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 98.4	$ 95.4	$ 287.9	$ 239.1
Less: General partner's incentive distribution paid	(20.0)	(9.1)	(51.9)	(22.1)
Subtotal	78.4	86.3	236.0	217.0
Less: General partner 2% ownership	(1.6)	(1.7)	(4.7)	(4.3)
Net income available to limited partners	76.8	84.6	231.3	212.7
Less: Pro forma additional general partner's distribution(1)	—	(12.6)	—	(23.8)
Net income available for limited partners under EITF 03-06	76.8	72.0	231.3	188.9
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	$ 76.8	$ 72.0	$ 231.3	$ 182.7
Denominator:				
Basic weighted average number of limited partner units outstanding	116.0	79.9	112.1	77.0
Effect of dilutive securities:				
Weighted average LTIP units	0.8	0.9	0.9	0.8
Diluted weighted average number of limited partner units outstanding	116.8	80.8	113.0	77.8
Basic net income per limited partner unit before cumulative effect of change in accounting principle(1)	$ 0.66	$ 0.90	$ 2.06	$ 2.37
Cumulative effect of change in accounting principle per limited partner unit(1)	—	—	—	0.08
Basic net income per limited partner unit(1)	$ 0.66	$ 0.90	$ 2.06	$ 2.45
Diluted net income per limited partner unit before cumulative effect of change in accounting principle(1)	$ 0.66	$ 0.89	$ 2.05	$ 2.35
Cumulative effect of change in accounting principle per limited partner unit(1)	—	—	—	0.08
Diluted net income per limited partner unit(1)	$ 0.66	$ 0.89	$ 2.05	$ 2.43

(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 $0.16 for the three months ended September 30, 2006, and $0.31 for the nine months ended September 30, 2006. The application of EITF 03-06 had no impact for the three and nine months ended September 30, 2007.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS

(In millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Earnings before interest, taxes, depreciation and amortization (“EBITDA”)				
Net income reconciliation				
EBITDA	$ 183.3	$ 138.8	$ 559.3	$ 358.7
Depreciation and amortization	(42.9)	(24.2)	(134.9)	(67.1)
Earnings before interest and taxes (“EBIT”)	140.4	114.6	424.4	291.6
Interest expense	(38.8)	(19.2)	(121.1)	(52.5)
Income tax expense	(3.2)	—	(15.4)	—
Net income	$ 98.4	$ 95.4	$ 287.9	$ 239.1
Cash flow from operating activities reconciliation				
EBITDA	$ 183.3	$ 138.8	$ 559.3	$ 358.7
Interest expense	(38.8)	(19.2)	(121.1)	(52.5)
Net change in assets and liabilities, net of acquisitions	542.1	349.4	491.1	(495.3)
Other items to reconcile to cash flows from operating activities:				
Cumulative effect of change in accounting principle	—	—	—	(6.3)
Equity earnings in unconsolidated entities, net of distributions	(3.3)	(1.5)	(11.1)	(2.1)
Inventory valuation adjustment	—	—	0.6	—
Gain on sale of investment assets	—	—	(3.9)	—
Net (gain)/loss on foreign currency revaluation	(1.2)	0.3	(3.2)	2.1
SFAS 133 mark-to-market adjustment	12.6	(17.9)	14.8	(14.8)
Equity compensation charge	1.0	10.3	41.4	27.1
Non-cash amortization of terminated interest rate hedging instruments	0.2	0.4	0.6	1.2
Net cash provided by (used in) operating activities	$ 695.9	$ 460.6	$ 968.5	$ (181.9)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Funds flow from operations (“FFO”)				
Net income	$ 98.4	$ 95.4	$ 287.9	$ 239.1
Undistributed equity earnings in unconsolidated entities	(3.3)	(1.5)	(11.1)	(2.1)
Depreciation and amortization	42.9	24.2	134.9	67.1
Deferred income tax expense	2.8	—	14.1	—
Non-cash amortization of terminated interest rate hedging instruments	0.2	0.4	0.6	1.2
FFO	141.0	118.5	426.4	305.3
Maintenance capital expenditures	(9.9)	(8.2)	(31.6)	(17.3)
FFO after maintenance capital expenditures	$ 131.1	$ 110.3	$ 394.8	$ 288.0

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS (continued)
(In millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income and earnings per limited partner unit excluding selected items impacting comparability				
Net income	$ 98.4	$ 95.4	$287.9	$239.1
Selected items impacting comparability	13.1	(7.6)	63.5	6.0
Adjusted net income	$ 111.5	$ 87.8	$351.4	$245.1
Net income available for limited partners under EITF 03-06	$ 76.8	$ 72.0	$231.3	$188.9
Limited partners 98% of selected items impacting comparability	12.8	(7.4)	62.2	5.9
Pro forma additional general partner distribution under EITF 03-06	—	12.6	—	23.8
Adjusted limited partners net income	$ 89.6	$ 77.2	$293.5	$218.6
Adjusted basic net income per limited partner unit	$ 0.77	$ 0.96	$ 2.62	$ 2.84
Adjusted diluted net income per limited partner unit	$ 0.77	$ 0.95	$ 2.60	$ 2.81
Basic weighted average units outstanding	116.0	79.9	112.1	77.0
Diluted weighted average units outstanding	116.8	80.8	113.0	77.8

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS (continued)
(In millions, except per unit data)

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
EBITDA excluding selected items impacting comparability				
EBITDA	$183.3	$138.8	$559.3	$358.7
Selected items impacting comparability(1)	13.1	(7.6)	52.7	6.0
Adjusted EBITDA	$196.4	$131.2	$612.0	$364.7

	Three Months Ended September 30 Transportation	Facilities	Marketing	Nine Months Ended September 30 Transportation	Facilities	Marketing
2007 Segment profit excluding selected items impacting comparability						
Reported segment profit	$ 91.8	$ 28.7	$ 60.3	$ 244.6	$ 79.5	$ 227.5
Selected items impacting comparability of segment profit:						
Equity compensation charge	0.2	0.2	0.1	19.1	5.1	13.7
SFAS 133 mark-to-market adjustment(2)	—	—	14.6	—	—	16.5
Segment profit excluding selected items impacting comparability	$ 92.0	$ 28.9	$ 75.0	$ 263.7	$ 84.6	$ 257.7
2006 Segment profit excluding selected items impacting comparability						
Reported segment profit	$ 53.3	$ 9.0	$ 76.2	$ 144.8	$ 19.6	$ 187.3
Selected items impacting comparability of segment profit:						
Equity compensation charge	5.0	1.3	4.0	13.2	3.5	10.4
SFAS 133 mark-to-market adjustment	—	—	(17.9)	—	—	(14.8)
Segment profit excluding selected items impacting comparability	$ 58.3	$ 10.3	$ 62.3	$ 158.0	$ 23.1	$ 182.9

(1) Excludes the deferred income tax expense associated with the initial cumulative effect of the recent change in Canadian tax legislation as it does not impact EBITDA.

(2) The SFAS 133 amount for the three- and nine-month periods ended September 30, 2007 excludes a $2.0 million gain and $1.7 million gain, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net but does not impact segment profit.

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