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 4, 2009**

Plains All American Pipeline, L.P.
(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code **713-646-4100**

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 — Press Release dated November 4, 2009.

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

Plains All American Pipeline, L.P. (the "Partnership or Plains") today issued a press release reporting its third-quarter 2009 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 updated detailed guidance for financial performance for the fourth quarter of calendar year 2009 with resulting performance for the full calendar year of 2009 (which supersedes guidance pertaining to 2009 contained in our Form 8-K furnished on August 5, 2009) and we are providing preliminary guidance for calendar year 2010. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this Item 7.01 shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Update of Fourth Quarter 2009 Guidance; Disclosure of Full Year 2010 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 net income to EBIT and EBITDA for the 2009 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled "Non-GAAP Reconciliation"), which presents an 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, inventory valuation adjustments net of gains and losses from related derivative activities, gains and losses from other derivative activities, foreign currency revaluations and loss on senior notes on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three months and twelve months ending December 31, 2009, as well as the preliminary guidance for calendar year 2010, is based on assumptions and estimates that we believe are reasonable given our assessment of historical trends (modified for changes in market conditions),

business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as LPG sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so we can provide no assurance that actual performance will fall within the guidance ranges. Please refer to 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 3, 2009. We undertake no obligation to publicly update or revise any forward-looking statements.

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

	Actual	Guidance [1]			
	9 Months Ended 9/30/2009	3 Months Ending December 31, 2009		12 Months Ending December 31, 2009	
		Low	High	Low	High
Segment Profit					
Net revenues (including equity earnings from unconsolidated entities)	$ 1,419	$ 448	$ 465	$ 1,867	$ 1,884
Field operating costs	(474)	(163)	(158)	(637)	(632)
General and administrative expenses	(153)	(57)	(54)	(210)	(207)
	792	228	253	1,020	1,045
Depreciation and amortization expense	(173)	(63)	(61)	(236)	(234)
Interest expense, net	(165)	(61)	(59)	(226)	(224)
Income tax expense	(1)	(2)	(2)	(3)	(3)
Other income (expense), net	17	(3)	(3)	14	14
Net Income	**$ 470**	**$ 99**	**$ 128**	**$ 569**	**$ 598**
Less: Net income attributable to noncontrolling interest	(1)	—	—	(1)	(1)
Net Income attributable to Plains	**$ 469**	**$ 99**	**$ 128**	**$ 568**	**$ 597**
Net Income to Limited Partners	$ 370	$ 61	$ 90	$ 431	$ 460
Basic Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	128	136	136	130	130
Net Income Per Unit	$ 2.84	$ 0.45	$ 0.66	$ 3.26	$ 3.48
Diluted Net Income Per Limited Partner Unit					
Weighted Average Units Outstanding	129	137	137	131	131
Net Income Per Unit	$ 2.82	$ 0.45	$ 0.65	$ 3.23	$ 3.46
EBIT	**$ 635**	**$ 162**	**$ 189**	**$ 797**	**$ 824**
EBITDA	**$ 808**	**$ 225**	**$ 250**	**$ 1,033**	**$ 1,058**
Selected Items Impacting Comparability					
Equity compensation charge	$ (36)	$ (11)	$ (11)	$ (47)	$ (47)
Inventory valuation adjustments net of gains and (losses) from related derivative activities	24	—	—	24	24
Gains (losses) from other derivative activities	54	—	—	54	54
Net gain on purchase of remaining 50% interest in PNGS	9	—	—	9	9
Loss on extinguishment of 7.125% notes	—	(4)	(4)	(4)	(4)
Net gain on foreign currency revaluation	12	—	—	12	12
	$ 63	$ (15)	$ (15)	$ 48	$ 48
Excluding Selected Items Impacting Comparability					
Adjusted Segment Profit					
Transportation	$ 373	$ 130	$ 136	$ 503	$ 509
Facilities	161	59	63	220	224
Marketing	203	50	65	253	268
Other Income (Expense), net	8	1	1	9	9
Adjusted EBITDA	$ 745	$ 240	$ 265	$ 985	$ 1,010
Adjusted Net Income	$ 406	$ 114	$ 143	$ 520	$ 549
Adjusted Basic Net Income per Limited Partner Unit	$ 2.35	$ 0.56	$ 0.77	$ 2.90	$ 3.12
Adjusted Diluted Net Income per Limited Partner Unit	$ 2.33	$ 0.56	$ 0.76	$ 2.88	$ 3.10

(1) The projected average foreign exchange rate was based on actual rates for October 2009 and $1.08 CAD to $1 USD for the remainder of 2009. The rate as of November 3, 2009 was $1.07 CAD to $1 USD.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
FX	Foreign currency exchange
General partner (GP)	As the context requires, "general partner" refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.
Class B units	Class B units of Plains AAP, L.P.

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, gathering systems, trucks and barges. 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 investment in the Butte and Frontier pipeline systems and Settoon Towing, in which we own non-controlling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, changes in the quantity of inventory held in tanks, 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 and mix 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	2009 Guidance	
	Nine Months Ended September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Average Daily Volumes (000 Bbls/d)			
All American	40	42	41
Basin	389	385	388
Capline	205	190	201
Line 63 / 2000	136	135	136
Salt Lake City Area Systems [1]	132	140	134
West Texas / New Mexico Area Systems [1]	375	365	372
Rainbow	184	185	184
Manito	62	65	63
Rangeland	54	50	53
Refined Products	96	100	97
Other	1,207	1,228	1,212
	2,880	2,885	2,881
Trucking	84	100	88
	2,964	2,985	2,969
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.46	$ 0.48[2]	$ 0.47[2]

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[1] The aggregate of multiple systems in the respective areas.
[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, LPG and natural gas, 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. On September 3, 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC. ("PNGS"). As a result of the transaction, PAA now owns 100% of PNGS's natural gas storage business and related operating entities, which is now accounted for on a consolidated basis beginning in September 2009. PAA historically accounted for its 50% indirect interest in PNGS under the equity method.

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	2009 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.)	56	56	56
Natural Gas Storage (Bcf/Mo.)	21	40	26
LPG Processing (MBbl/d)	16	17	16
Facilities Activities Total [(1)]			
Avg. Capacity (MMBbls/Mo.)	60	64	61
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.30	$ 0.32[(2)]	$ 0.30[(2)]

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(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 barrel of crude oil ratio; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

(2) Mid-point of guidance.

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

- the purchase of U.S. and Canadian 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 and the seasonal storage of LPG;
- 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 to maximize profits; and
- 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 remainder of 2009 reflect the current market structure and seasonal, weather-related variations in LPG sales. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory, based on current and anticipated market conditions. Volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, production declines, weather, and other external factors beyond our control. 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. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual	2009 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 purchases	619	600	614
LPG sales	88	150	104
Refined products sales	34	35	34
Waterborne foreign crude oil imported	54	60	56
	795	845	808
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.93	$ 0.74[(1)]	$ 0.88[(1)]

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(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 may vary during any one period due to gains and losses on intermittent sales of assets, asset retirement obligations, or asset impairments.

4. *Selected Items Impacting Comparability.* Our operating results are impacted by items that affect comparability between reporting periods, such as the equity compensation benefit or charge associated with our long-term incentive programs. In addition, our actual results will reflect certain mark-to-market items such as gains and losses related to derivative activities, gains and losses from unrealized foreign currency transactions, and inventory valuation adjustments. Our adjusted results exclude these selected items impacting comparability until such time as the underlying and offsetting physical transaction settles. Although the economics of these transactions as a whole are embedded in our guidance presented here, our selected items impacting comparability for future periods do not reflect these items as there is no accurate way to forecast the timing and magnitude of their ultimate effect. The magnitude of these items depends on market prices and exchange rates at a point in time. Accordingly, our actual results could differ materially from our projections.

5. *Acquisitions and Other Capital Expenditures.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions to which we may commit after the date hereof. We forecast capital expenditures during calendar 2009 to be approximately $380 million for expansion projects with an additional $85 to $95 million for maintenance capital projects. During the first nine months of 2009, we invested $261 million and $56 million, respectively, for expansion and maintenance capital projects. Following are some of the more notable projects and forecasted expenditures for the year:

		Calendar 2009 (in millions)
Expansion Capital		
· St. James Phase III [(1)]	$	73
· Rangeland tankage and connections		35
· Kerrobert pumping project		34
· Cushing Phase VII		29
· Patoka Phase II & III		20
· Nipisi storage and truck terminal		20
· Pier 400		18
· Pine Prairie		15
· Salt Lake City pipeline		14
· Paulsboro		12
· Other projects, including acquisition related expansion projects [(2)]		110
		380
Maintenance Capital		85 - 95
Total Projected Capital Expenditures (excluding acquisitions)	$	465 - 475

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(1) Includes a dock and condensate tanks.
(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2008.

6. *Capital Structure.* This guidance is based on our capital structure as of September 30, 2009 as adjusted for the retirement on October 5, 2009 of the 7.125% Senior Notes due June 2014.

7. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, forecasted acquisitions and 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 rate assumptions for variable rate debt are based on the current forward LIBOR curve.

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 inventory stored in a contango market. We treat interest on contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

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 (in millions, except per unit data)			
	9 Months Ended	3 Months Ending December 31, 2009		12 Months Ending December 31, 2009	
	09/30/09	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:					
Net Income attributable to Plains	$ 469	$ 99	$ 128	$ 568	$ 597
Less: General partners incentive distribution paid[(1)]	(92)	(35)	(35)	(127)	(127)
Subtotal	377	64	93	441	470
Less: General partner 2% ownership [(1)]	(7)	(3)	(3)	(10)	(10)
Net income available to limited partners	370	61	90	431	460
Adjustment in accordance with application of the two-class method for MLPs [(1)]	(8)	—	—	(8)	(8)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 362	$ 61	$ 90	$ 423	$ 452
Denominator:					
Basic weighted average number of limited partner units	128	136	136	130	130
Effect of dilutive securities:					
Weighted average LTIP units	1	1	1	1	1
Diluted weighted average number of limited partner units	129	137	137	131	131
Basic net income per limited partner unit	$ 2.84	$ 0.45	$ 0.66	$ 3.26	$ 3.48
Diluted net income per limited partner unit	$ 2.82	$ 0.45	$ 0.65	$ 3.23	$ 3.46

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(1) We allocate net income to our general partner based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). Guidance issued by the FASB requires that the distribution pertaining to the current period's net income, which is to be paid in the subsequent quarter, be utilized in the earnings per unit calculation. We reflect the impact of this difference as the "Adjustment in accordance with application of the two-class method for MLPs."

In conjunction with the Pacific, Rainbow and PNGS acquisitions, our general partner reduced the amounts due it as incentive distributions by an aggregate amount of $83 million. Approximately $54 million of this reduction was realized as of September 30, 2009. Incentive distributions will be reduced by $6 million for the balance of 2009, $16 million in 2010 and $7 million in 2011.

The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Based on the current number of units outstanding, each $0.05 per unit annual increase or decrease in the distribution relative to forecasted amounts decreases or increases net income available for limited partners by approximately $7 million ($0.05 per unit) on an annualized basis.

9. *Equity Compensation Plans*. The majority of grants outstanding under our equity compensation plans (LTIP and Class B units) 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 outstanding as of November 4, 2009, estimated vesting dates range from May 2010 to May 2019 and annualized distribution levels range from $3.00 to $4.50. For some awards, a percentage of any units remaining unvested as of a date certain will vest on such date and all others are forfeited.

   On October 19, 2009, we declared an annualized distribution of $3.68 payable on November 13, 2009 to our unitholders of record as of November 3, 2009. We have made the assessment that a $3.90 distribution level is probable of occurring and accordingly, for grants that vest at annualized distribution levels of $3.90 or less, guidance includes an accrual over the applicable service period at an assumed market price of approximately $50.00 per unit as well as the fair value associated with awards that will vest on a date certain. The actual amount of equity compensation expense amortization in any given period 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 the amortization in the early years, (iv) the probability assessment of achieving future distribution rates, and (v) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at September 30, 2009 would change the fourth-quarter equity compensation expense by approximately $5 million. Therefore, actual net income could differ materially from our projections.

10. *Reconciliation of Net Income to EBIT and EBITDA* . The following table reconciles net income to EBIT and EBITDA, for the three-month and twelve-month guidance ranges ending December 31, 2009.

	3 Months Ending December 31, 2009		12 Months Ending December 31, 2009	
	Low	High	Low	High
Reconciliation to EBITDA				
Net Income attributable to Plains	$ 99	$ 128	$ 568	$ 597
Interest expense	(61)	(59)	(226)	(224)
Income tax expense	(2)	(2)	(3)	(3)
EBIT	162	189	797	824
Depreciation and amortization	(63)	(61)	(236)	(234)
EBITDA	$ 225	$ 250	$ 1,033	$ 1,058

Preliminary Calendar 2010 Guidance

The following range for preliminary adjusted EBITDA guidance for 2010 is based on the following:

The low end of the range assumes —

- a prolonged recovery from the current/recent U.S. economic recession, translating into a continuation of a weak U.S. economy throughout all of 2010;
- Continuation of weak domestic demand for crude oil and transportation fuels (currently 10% below average consumption levels realized in 2005 to 2007);
- Reduced import levels of crude oil (2009 year-to-date is 8% below 2005 to 2008 averages and currently is 12% below such averages);
- Weak market structure for crude oil with limited structural volatility (thus anticipating the market will be either slightly backwardated or slightly contango); and
- A continuation of the current abnormally tight grade differentials relative to average differentials experienced in the 2005 to 2008 period.

The high end of the range assumes —

- The same overall economic and energy market conditions as the low end of the range for the first half of 2010, but incorporating a gradual recovery in the economy during the second half of 2010; and
- An increase in the second half of 2010 of domestic consumption of crude oil and transportation fuels and crude oil imports and a resulting increase in structural volatility for crude oil and expanded grade differentials.

Preliminary Calendar 2010 Guidance (in millions)

	Low	High
Adjusted EBITDA	$ 1,000	$ 1,080
Depreciation and amortization	(255)	(245)
Interest expense	(255)	(245)
Taxes	(15)	(10)
Adjusted Net Income	$ 475	$ 580

Maintenance Capital Expenditures	$ 90	$ 80

Our preliminary guidance for interest expense is based on our capital structure as of September 30, 2009 (adjusted for the retirement of the $250 million Senior Notes on October 5, 2009), the current market outlook for floating interest rates, approved capital projects for 2009 and the assumption that 2010 capital projects including base gas will range between $300 million to $400 million. Our preliminary guidance for depreciation and amortization is based on projected depreciation from our present asset base, and continued development of our portfolio of projects. Our preliminary guidance for maintenance capital expenditures is based on our

estimate of the range of recurring expenditures that are expected to average approximately $85 million in any given year. All amounts assume a foreign exchange rate of $1.10 CAD to $1.00 USD. The adjusted net income and adjusted EBITDA shown above exclude selected items impacting comparability such as equity compensation and gains and losses related to derivative activities (see note 4 above) as it is impractical to forecast such items.

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,” as well as 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:

- failure to implement or capitalize on planned internal growth projects;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the success of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;
- 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, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;
- 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 transportation throughput requirements;
- the availability of, and our ability to consummate, acquisition or combination opportunities,
- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;
- the 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, grade differentials and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- the effects of competition;
- 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;
- future developments and circumstances at the time distributions are declared;
- general economic, market or business conditions and the amplification of other risks caused by deteriorated financial markets, capital constraints and pervasive liquidity concerns; 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: PAA GP LLC, its general partner

By: PLAINS AAP, L. P., its sole member

By: PLAINS ALL AMERICAN GP LLC, its general partner

Date: November 4, 2009

By: /s/ AL SWANSON
Name: Al Swanson
Title: *Senior Vice President and Chief Financial Officer*

News Release

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Al Swanson
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<u>FOR IMMEDIATE RELEASE</u>

Plains All American Pipeline, L.P. Reports
Solid Third-Quarter 2009 Results

(Houston — November 5, 2009) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income of $122 million, or $0.65 per diluted limited partner unit, for the third quarter of 2009 as compared to net income for the third quarter of 2008 of $206 million, or $1.41 per diluted limited partner unit. The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $242 million for the third quarter of 2009, compared with EBITDA of $310 million for the third quarter of 2008.

The Partnership's reported results include the impact of items that affect comparability between reporting periods. These items are excluded from adjusted results, as further described in the table below. Accordingly, the Partnership's third-quarter 2009 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $114 million, $0.59 and $234 million, respectively, as compared to third-quarter 2008 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA of $119 million, $0.71 and $223 million, respectively. (See the section of this release entitled "Non-GAAP Financial Measures" and the attached tables for discussion of EBITDA and other non-GAAP financial measures, and reconciliations of such measures to the comparable GAAP measures.)

"Plains All American has been very active and productive in the four months since the end of the second quarter" said Greg L. Armstrong, Chairman & CEO of Plains All American. "We delivered operating and financial results at the high end of guidance, acquired the remaining 50% interest in PAA Natural Gas Storage (PNGS), raised over $1.2 billion in the capital markets at very attractive rates and increased our annualized distribution by 6 cents or 1.7% to $3.68 per unit. We also ended the third quarter with a solid balance sheet and over $1.6 billion of available committed liquidity, of which approximately $260 million was used in early October to prepay our 7.125% senior notes."

For the first nine months of 2009, the Partnership reported net income of $469 million, or $2.82 per diluted limited partner unit, as compared to net income for the first nine months of 2008 of $339 million, or $2.08 per diluted limited partner unit. The Partnership reported EBITDA of $808 million for the first nine months of 2009, compared with EBITDA of $639 million for the first nine months of 2008. Adjusted net income, adjusted net income per diluted limited partner unit and adjusted

EBITDA for the first nine months of 2009 were $406 million, $2.33 and $745 million, respectively. Adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the first nine months of 2008 were $352 million, $2.19 and $652 million, respectively.

The following table summarizes selected items that the Partnership believes impact comparability of financial results between reporting periods (amounts in millions, except per unit amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Selected items impacting comparability				
Equity compensation charge [1]	$ (12)	$ (3)	$ (36)	$ (23)
Inventory valuation adjustments net of gains and (losses) from related derivative activities [2]	—	4	24	4
Gains/(losses) from other derivative activities [2] [3]	11	94	54	3
Gains on acquisition-related foreign currency and linefill hedges	—	—	—	11
Net gain on purchase of remaining 50% interest in PNGS	9	—	9	—
Net gain/(loss) on foreign currency revaluation	—	(8)	12	(8)
Selected items impacting comparability	8	87	63	(13)
Less: GP 2% portion of selected items impacting comparability	—	(2)	(1)	—
LP 98% portion of selected items impacting comparability	$ 8	$ 85	$ 62	$ (13)
Impact to basic net income per limited partner unit	$ 0.06	$ 0.70	$ 0.49	$ (0.11)
Impact to diluted net income per limited partner unit	$ 0.06	$ 0.70	$ 0.49	$ (0.11)

(1) The equity compensation charge for the three and nine months ended September 30, 2009 and 2008 excludes the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans is approximately $4 million and $1 million for the three months ended September 30, 2009 and 2008, respectively, and approximately $11 million and $3 million for the nine months ended September 30, 2009 and 2008, respectively.

(2) Gains and losses from derivative activities related to revalued inventory are included in the line item "Inventory valuation adjustments net of gains and (losses) from related derivative activities;" gains and losses from derivative activities not related to revalued inventory are included in the line item "Gains/(losses) from other derivative activities."

(3) Gains and losses from other derivative activities for the nine months ended September 30, 2009 includes losses of approximately $1 million related to interest rate derivatives, which are included in other income/(expense), net, but do not impact segment profit.

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The following tables present certain selected financial information by segment for the third-quarter and first nine months reporting periods (amounts in millions):

	Three Months Ended September 30, 2009			Three Months Ended September 30, 2008		
	Transportation Operations	Facilities Operations	Marketing Operations	Transportation Operations	Facilities Operations	Marketing Operations
Revenues [1]	$ 250	$ 97	$ 4,645	$ 242	$ 69	$ 8,676
Purchases and related costs [1]	(15)	(1)	(4,534)	(23)	—	(8,471)
Field operating costs (excluding equity compensation benefit/charge) [1]	(86)	(32)	(45)	(86)	(27)	(50)
Equity compensation benefit/(charge) - operations	(2)	—	—	1	—	—
Segment G&A expenses (excluding equity compensation charge) [2]	(14)	(7)	(17)	(14)	(5)	(16)
Equity compensation charge - general and administrative	(6)	(3)	(5)	(2)	(1)	(1)
Equity earnings in unconsolidated entities	2	3	—	1	3	—
Reported segment profit	$ 129	$ 57	$ 44	$ 119	$ 39	$ 138
Selected items impacting comparability of segment profit:						
Equity compensation charge [3]	6	2	4	1	1	1
Inventory valuation adjustments net of (gains)/losses from related derivative activities [4]	—	—	—	—	—	(4)
(Gains)/losses from other derivative activities [4]	—	—	(11)	—	—	(94)
Net loss on foreign currency revaluation	—	—	—	—	—	8
Subtotal	6	2	(7)	1	1	(89)
Segment profit excluding selected items impacting comparability	$ 135	$ 59	$ 37	$ 120	$ 40	$ 49
Maintenance capital	$ 9	$ 2	$ 1	$ 13	$ 5	$ 1

	Nine Months Ended September 30, 2009			Nine Months Ended September 30, 2008		
	Transportation Operations	Facilities Operations	Marketing Operations	Transportation Operations	Facilities Operations	Marketing Operations
Revenues [1]	$ 714	$ 259	$ 11,877	$ 680	$ 194	$ 24,594
Purchases and related costs [1]	(47)	(1)	(11,389)	(68)	—	(24,211)
Field operating costs (excluding equity compensation charge) [1]	(249)	(85)	(139)	(246)	(76)	(135)
Equity compensation charge - operations	(6)	(1)	(1)	(1)	—	—
Segment G&A expenses (excluding equity compensation charge) [2]	(45)	(18)	(51)	(42)	(13)	(49)
Equity compensation charge - general and administrative	(17)	(7)	(15)	(12)	(5)	(9)
Equity earnings in unconsolidated entities	5	8	—	4	7	—
Reported segment profit	$ 355	$ 155	$ 282	$ 315	$ 107	$ 190
Selected items impacting comparability of segment profit:						
Equity compensation charge [3]	18	6	12	12	4	7
Inventory valuation adjustments net of (gains)/losses from related derivative activities [4]	—	—	(24)	—	—	(4)

(Gains)/losses from other derivative activities [4] [5]	—	—	(55)	—	—	(3)
Net (gain)/loss on foreign currency revaluation	—	—	(12)	—	—	8
Subtotal	18	6	(79)	12	4	8
Segment profit excluding selected items impacting comparability	$ 373	$ 161	$ 203	$ 327	$ 111	$ 198
Maintenance capital	$ 40	$ 11	$ 5	$ 38	$ 15	$ 3

(1) Includes intersegment amounts.

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

(3) The equity compensation charge for the three and nine months ended September 30, 2009 and 2008 excludes the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans is approximately $4 million and $1 million for the three months ended September 30, 2009 and 2008, respectively, and approximately $11 million and $3 million for the nine months ended September 30, 2009 and 2008, respectively.

(4) Gains and losses from derivative activities related to revalued inventory are included in the line item “Inventory valuation adjustments net of (gains)/losses from related derivative activities;” gains and losses from derivative activities not related to revalued inventory are included in the line item “Gains/(losses) from other derivative activities.”

(5) Gains and losses from other derivative activities for the nine months ended September 30, 2009 includes losses of approximately $1 million related to interest rate derivatives, which are included in other income/(expense), net, but do not impact segment profit.

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Adjusted segment profit for the Transportation segment for the third quarter of 2009 increased 13% over corresponding 2008 results primarily due to higher average pipeline tariffs and increased pipeline loss allowance revenue.

Adjusted segment profit for the Facilities segment for the third quarter of 2009 increased 48% over comparable 2008 results principally due to capacity increases from recently completed capital projects, recent acquisitions, including the PNGS acquisition, and higher average lease rates at various facilities.

Adjusted segment profit for the Marketing segment for the third quarter of 2009 decreased 25% from comparable 2008 results. This decrease is due to a number of factors including declines in margins due to tighter crude oil quality differentials and lower LPG margins, partially offset by a favorable contango market and lower operating costs.

The Partnership’s basic weighted average units outstanding for the third quarter of 2009 totaled 130 million (131 million diluted) as compared to 128 million (129 million diluted) in last year’s third quarter. At September 30, 2009, the Partnership had approximately 136.1 million units outstanding, long-term debt of approximately $4.1 billion ($437 million of which supports hedged inventory) and an adjusted long-term debt-to-total capitalization ratio of 47%.

The Partnership has declared a quarterly distribution of $0.92 per unit ($3.68 per unit on an annualized basis) payable November 13, 2009 on its outstanding limited partner units. This distribution represents an increase of 3.1% over the quarterly distribution paid in November 2008 and an increase of 1.7% from the August 2009 distribution level.

Prior to its November 5th conference call, the Partnership will furnish a current report on Form 8-K, which will include material in this press release and financial and operational guidance for the fourth quarter 2009, and preliminary 2010 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, exchange rates, mechanical interruptions, acquisitions and numerous other factors. These types of variations are not separately identified in this release, but will be discussed, as applicable, in management's discussion and analysis of operating results in our Quarterly Report on Form 10-Q.

A reconciliation of net income to EBITDA and EBITDA to 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, to the most comparable GAAP measures. To access the information, investors should click on the "Investor Relations" link on the Partnership's home page and then the "Non-GAAP Reconciliation" link on the Investor Relations page.

Conference Call

The Partnership will host a conference call at 11:00 AM (Eastern) on Thursday, November 5, 2009 to discuss the following items:

1. The Partnership's third-quarter 2009 performance;

2. The status of major expansion projects;

3. Capitalization and liquidity;

4. Financial and operating guidance for the fourth quarter 2009 and preliminary 2010 guidance; and

5. The Partnership's outlook for the future.

Webcast Instructions

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

If you are unable to participate in the webcast, please dial 800-230-1059, or, for international callers, 612-234-9960, at approximately 10:55 AM (Eastern). No password 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 PAA's website at www.paalp.com.

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial 800-475-6701, or, for international callers, 320-365-3844, and replay access code 116801. The replay will be available beginning Thursday, November 5, 2009, at approximately 12:00 PM (Central) and continue until 11:59 PM (Central) Saturday,December 5, 2009 .

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. The Partnership is also engaged in the development and operation of natural gas storage facilities. The Partnership is headquartered in Houston, Texas.

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Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this release are forward-looking statements that involve certain risks and uncertainties that could cause actual results to differ materially from results anticipated in the forward-looking statements. These risks and uncertainties include, among other things, failure to implement or capitalize on planned internal growth projects; maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties; continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business; the success of our risk management activities; environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves; abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems; 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, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves; 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 transportation throughput requirements; the availability of, and our ability to consummate, acquisition or combination opportunities; our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness; the 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, grade differentials and volatility (or lack thereof); the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations; the effects of competition; 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; future developments and circumstances at the time distributions are declared; general economic, market or business conditions and the amplification of other risks caused by deteriorated financial markets, capital constraints and

pervasive liquidity concerns; 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,	
	2009	2008	2009	2008
REVENUES	$ 4,857	$ 8,862	$ 12,442	$ 25,118
COSTS AND EXPENSES				
Purchases and related costs	4,417	8,369	11,036	23,929
Field operating costs	163	162	474	458
General and administrative expenses	52	39	153	130
Depreciation and amortization	59	49	173	150
Total costs and expenses	4,691	8,619	11,836	24,667
OPERATING INCOME	166	243	606	451
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	5	4	13	11
Interest expense	(59)	(52)	(165)	(143)
Other income/(expense), net	12	14	17	27
INCOME BEFORE TAX	124	209	471	346
Current income tax expense	(2)	(3)	(5)	(9)
Deferred income tax benefit	—	—	4	2
NET INCOME	122	206	470	339
Less: Net income attributable to the noncontrolling interest	—	—	(1)	—
NET INCOME ATTRIBUTABLE TO PLAINS	$ 122	$ 206	$ 469	$ 339
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 88	$ 173	$ 370	$ 256
GENERAL PARTNER	$ 34	$ 33	$ 99	$ 83
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 1.42	$ 2.84	$ 2.10
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 1.41	$ 2.82	$ 2.08
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	130	123	128	120
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	131	124	129	121

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

OPERATING DATA [(1)]

	Three Months Ended	Nine Months Ended

	September 30,		September 30,	
	2009	2008	2009	2008
Transportation activities (Average Daily Volumes, thousands of barrels):				
Tariff activities				
All American	43	44	40	44
Basin	335	375	389	372
Capline	205	216	205	218
Line 63/Line 2000	141	131	136	151
Salt Lake City Area Systems [2]	152	90	132	94
West Texas/New Mexico Area Systems [2]	355	370	375	367
Manito	62	68	62	70
Rainbow	176	191	184	108
Rangeland	51	54	54	58
Refined products	100	108	96	110
Other	1,219	1,234	1,207	1,238
Tariff activities total	2,839	2,881	2,880	2,830
Trucking	80	101	84	96
Transportation activities total	2,919	2,982	2,964	2,926
Facilities activities (Average Monthly Volumes):				
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	56	55	56	54
Natural gas storage (average monthly capacity in billions of cubic feet) [3]	27	14	21	13
LPG processing (average throughput in thousands of barrels per day)	17	17	16	16
Facilities activities total (average monthly capacity in millions of barrels) [4]	61	58	60	57
Marketing activities (Average Daily Volumes, thousands of barrels):				
Crude oil lease gathering purchases	602	638	619	663
Refined products sales	32	27	34	24
LPG sales	61	67	88	85
Waterborne foreign crude oil imported	46	77	54	84
Marketing activities total	741	809	795	856

(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 respective areas.

(3) In September 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC ("PNGS") from Vulcan Gas Storage LLC, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for 2008 and January through August 2009 are netted to our 50% interest in PNGS. September 2009 volumes represent our 100% interest in PNGS.

(4) Facilities total is 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 period and divided by the number of months in the period.

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(In millions)

	September 30, 2009	December 31, 2008
ASSETS		
Current assets	$ 3,024	$ 2,596
Property and equipment, net	6,197	5,059
Linefill and base gas	479	425
Long-term inventory	129	139
Investment in unconsolidated entities	68	257
Goodwill	1,270	1,210
Other long-term assets, net	326	346

Total assets	$ 11,493	$ 10,032
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 2,859	$ 2,960
Long-term debt under credit facilities and other	7	40
Senior notes, net of unamortized net discount	4,135	3,219
Other long-term liabilities and net deferred credits	265	261
Total liabilities	7,266	6,480
Partners' capital excluding noncontrolling interest	4,163	3,552
Noncontrolling interest	64	—
Total partners' capital	4,227	3,552
Total liabilities and partners' capital	$ 11,493	$ 10,032

CREDIT RATIOS
(In millions)

	September 30, 2009	Adjustment (1)	September 30, 2009 Adjusted
Short-term debt	$ 692	$ 437	$ 1,129
Long-term debt	4,142	(437)	3,705
Total debt	$ 4,834	$ —	$ 4,834
Long-term debt	4,142	(437)	3,705
Partners' Capital	4,227	—	4,227
Total book capitalization	$ 8,369	$ (437)	$ 7,932
Total book capitalization including short-term debt	$ 9,061	$ —	$ 9,061
Long-term debt to total book capitalization	49%		47%
Total debt to total book capitalization including short-term debt	53%		53%

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(1) The adjustment represents the portion of the 4.25% senior notes due September 2012 that has been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities. These notes were issued in July 2009 and the proceeds are being used to supplement capital available from our hedged inventory facility.

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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,	
	2009	2008	2009	2008
Numerator for basic and diluted earnings per limited partner unit:				
Net Income Attributable to Plains	$ 122	$ 206	$ 469	$ 339
Less: General partner's incentive distribution paid (1)	(32)	(30)	(92)	(78)
Subtotal	90	176	377	261
Less: General partner 2% ownership (1)	(2)	(3)	(7)	(5)
Net income available to limited partners	88	173	370	256
Adjustment in accordance with application of the two-class method for MLPs (1)	(3)	2	(8)	(5)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 85	$ 175	$ 362	$ 251
Denominator:				
Basic weighted average number of limited partner units outstanding	130	123	128	120
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Diluted weighted average number of limited partner units outstanding	131	124	129	121
Basic net income per limited partner unit	$ 0.65	$ 1.42	$ 2.84	$ 2.10

Diluted net income per limited partner unit	$ 0.65	$ 1.41	$ 2.82	$ 2.08

(1) We allocate net income to our general partner based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). Guidance issued by the FASB requires that the distribution pertaining to the current period's net income, which is to be paid in the subsequent quarter, be utilized in the earnings per unit calculation. We reflect the impact of this difference as the "Adjustment in accordance with application of the two-class method for MLPs."

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

FINANCIAL DATA RECONCILIATIONS
(In millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Net income attributable to Plains to earnings before interest, taxes, depreciation and amortization ("EBITDA") reconciliation				
Net Income Attributable to Plains	$ 122	$ 206	$ 469	$ 339
Add: Interest expense	59	52	165	143
Add: Income tax expense	2	3	1	7
Earnings before interest and taxes ("EBIT")	183	261	635	489
Add: Depreciation and amortization	59	49	173	150
EBITDA	$ 242	$ 310	$ 808	$ 639

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Cash flow from operating activities reconciliation				
EBITDA	$ 242	$ 310	$ 808	$ 639
Current income tax expense	(2)	(3)	(5)	(9)
Interest expense	(59)	(52)	(165)	(143)
Net change in assets and liabilities, net of acquisitions	(137)	(587)	(338)	(275)
Other items to reconcile to cash flows from operating activities:				
Equity compensation charge	16	3	47	27
Net cash provided by operating activities	$ 60	$ (329)	$ 347	$ 239

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
Funds flow from operations ("FFO")				
Net Income Attributable to Plains	$ 122	$ 206	$ 469	$ 339
Equity earnings in unconsolidated entities, net of distributions	(3)	(3)	(6)	(4)
Depreciation and amortization	59	49	173	150
Deferred income tax benefit	—	—	(4)	(2)
FFO	178	252	632	483
Maintenance capital	(12)	(19)	(56)	(56)
FFO after maintenance capital	$ 166	$ 233	$ 576	$ 427

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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,	
	2009	2008	2009	2008
Net income attributable to Plains and earnings per limited partner unit excluding selected items impacting comparability				
Net Income Attributable to Plains	$ 122	$ 206	$ 469	$ 339
Selected items impacting comparability	(8)	(87)	(63)	13
Adjusted net income	$ 114	$ 119	$ 406	$ 352
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 85	$ 175	$ 362	$ 251
Limited partners' 98% of selected items impacting comparability	(8)	(85)	(62)	13
Adjusted limited partners' net income	$ 77	$ 90	$ 300	$ 264
Adjusted basic net income per limited partner unit	$ 0.59	$ 0.72	$ 2.35	$ 2.21
Adjusted diluted net income per limited partner unit	$ 0.59	$ 0.71	$ 2.33	$ 2.19
Basic weighted average units outstanding	130	123	128	120
Diluted weighted average units outstanding	131	124	129	121

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
EBITDA excluding selected items impacting comparability				
EBITDA	$ 242	$ 310	$ 808	$ 639
Selected items impacting comparability	(8)	(87)	(63)	13
Adjusted EBITDA	$ 234	$ 223	$ 745	$ 652

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