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) — **February 6, 2013**

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 February 6, 2013

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 fourth quarter and full year 2012 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 first quarter and full year 2013 detailed guidance for financial performance. 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 (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.

Disclosure of First Quarter and Full Year 2013 Guidance

We based our guidance for the three-month period ending March 31, 2013 and twelve-month period ending December 31, 2013 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 NGL sales) and acquisition synergies. 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 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 February 5, 2013. We undertake no obligation to publicly update or revise any forward-looking statements.

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. EBIT and EBITDA (each as defined below in Note 1 to the "Operating and Financial Guidance" table) are non-GAAP financial measures. Net income represents one of the two most directly comparable GAAP measures to EBIT and EBITDA. In Note 10 below, we reconcile net income to EBIT and EBITDA for the 2013 guidance periods presented. Cash flow from operating activities is the other most comparable GAAP measure. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA, because such reconciliations are impractical for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled "Non-GAAP Reconciliations"), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. In addition, within our guidance, we have highlighted the impact of equity compensation expense. Due to the nature of the selected items, certain of the selected items impacting comparability may impact certain non-GAAP financial measures but not impact other non-GAAP financial measures.

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

	Guidance [1]			
	3 Months Ending March 31, 2013		12 Months Ending December 31, 2013	
	Low	High	Low	High
Segment Profit				
Net revenues (including equity earnings from unconsolidated entities)	$ 1,009	$ 1,044	$ 3,595	$ 3,665
Field operating costs	(340)	(330)	(1,340)	(1,320)
General and administrative expenses	(98)	(93)	(333)	(323)
	571	621	1,922	2,022
Depreciation and amortization expense	(86)	(82)	(353)	(343)
Interest expense, net	(81)	(77)	(330)	(320)
Income tax benefit (expense)	(29)	(25)	(63)	(53)
Other income (expense), net	1	1	4	4
Net Income	**376**	**438**	**1,180**	**1,310**
Less: Net income attributable to noncontrolling interests	(8)	(8)	(31)	(31)
Net Income attributable to Plains	**$ 368**	**$ 430**	**$ 1,149**	**$ 1,279**
Net Income to Limited Partners [2]	$ 278	$ 338	$ 766	$ 893
Basic Net Income Per Limited Partner Unit [2]				
Weighted Average Units Outstanding	336	336	340	340
Net Income Per Unit	$ 0.82	$ 1.00	$ 2.24	$ 2.61
Diluted Net Income Per Limited Partner Unit [2]				
Weighted Average Units Outstanding	339	339	342	342
Net Income Per Unit	$ 0.81	$ 0.99	$ 2.23	$ 2.60
EBIT	**$ 486**	**$ 540**	**$ 1,573**	**$ 1,683**
EBITDA	**$ 572**	**$ 622**	**$ 1,926**	**$ 2,026**
Selected Items Impacting Comparability				
Equity compensation expense	$ (18)	$ (18)	$ (49)	$ (49)
Other	—	—	1	1
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (18)	$ (18)	$ (48)	$ (48)
Excluding Selected Items Impacting Comparability				
Adjusted Segment Profit				
Transportation	$ 170	$ 185	$ 810	$ 835
Facilities	145	155	595	610
Supply and Logistics	274	299	565	625
Other income, net	1	1	5	5
Adjusted EBITDA	$ 590	$ 640	$ 1,975	$ 2,075
Adjusted Net Income attributable to Plains	$ 386	$ 448	$ 1,197	$ 1,327
Basic Net Income Per Limited Partner Unit [2]	$ 0.87	$ 1.05	$ 2.38	$ 2.75
Diluted Net Income Per Limited Partner Unit [2]	$ 0.86	$ 1.04	$ 2.36	$ 2.73

(1) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three-month period ending March 31, 2013 and the twelve-month period ending December 31, 2013. The rate as of February 5, 2013 was $1.00 Canadian to $1.00 U.S. A $0.05 change in the FX rate will impact annual adjusted EBITDA by approximately $21 million.

(2) We calculate net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

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
DCF	Distributable Cash Flow
FASB	Financial Accounting Standards Board
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
NGL	Natural gas liquids. Includes ethane and natural gasoline products as well as propane and butane, which are often referred to as liquefied petroleum gas (LPG). When used in this document NGL refers to all NGL products including LPG.
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.

2. *Operating Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. 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, NGL 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. Our transportation segment also includes our equity earnings from our investments in Settoon Towing and the White Cliffs, Butte, Frontier and Eagle Ford pipeline systems, in which we own non-controlling interests.

    Pipeline volume estimates are based on historical trends, production forecasts, estimated refinery operating levels, and assumed completion of internal growth projects. Actual volumes will be influenced by maintenance schedules at refineries, actual production trends, weather and other natural occurrences including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. We forecast adjusted segment profit 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 transportation volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Guidance	
	Three Months Ending Mar 31, 2013	**Twelve Months Ending Dec 31, 2013**
Average Daily Volumes (MBbls/d)		
Crude Oil / Refined Products Pipelines		
All American	30	35
Bakken Area Systems	120	135
Basin/Mesa	750	670
Capline	150	150
Eagle Ford Area Systems	50	115
Line 63 / 2000	100	115
Manito	50	50
Mid-Continent Area Systems	275	270
Permian Basin Area Systems	485	590
Rainbow	145	155
Rangeland	65	65
Salt Lake City Area Systems	140	150
White Cliffs	20	20
Other	905	830
NGL Pipelines		
Co-Ed	55	55
Other	185	175
	3,525	3,580
Trucking	110	125
	3,635	3,705
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability	$ 0.54 [1]	$ 0.61 [1]

(1) 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, NGL and natural gas, as well as NGL fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our railcar facilities, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from gas processing services. Adjusted segment profit is forecasted 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.

	Guidance	
	Three Months Ending Mar 31, 2013	Twelve Months Ending Dec 31, 2013
Operating Data		
Crude Oil, Refined Products, and NGL terminalling and Storage (MMBbls/Mo.)	95	96
Crude Oil Rail Unload / Load Volumes (MBbl/d)	235	280
Natural Gas Storage (Bcf/Mo.)	93	96
NGL Fractionation (MBbls/d)	95	95
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) (1)	121	123
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability	$ 0.41(2)	$ 0.41(2)

(1) Calculated as the sum of: (i) crude oil, refined products and NGL storage capacity; (ii) rail load and unload volumes (based on estimated utilized capacity), multiplied by the number of days in the period and divided by the number of months in the period; (iii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes (based on estimated utilized capacity), 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. *Supply and Logistics*. Our supply and logistics segment operations generally consist of the following activities:

- the purchase of U.S. and Canadian crude oil at the wellhead, the bulk purchase of crude oil at pipeline, terminal and rail facilities, and the purchase of cargos at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of NGL;
- the purchase of NGL from producers, refiners, processors and other marketers;
- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels to various delivery points, including but not limited to refineries, connecting carriers and fractionation facilities.

We characterize a substantial portion of the profit generated by our supply and logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market as well as any operating and general and administrative expenses. The level of profit associated with a portion of the other activities we conduct in the supply and logistics 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 March 31, 2013 reflect the current market structure and for the twelve-month period ending December 31, 2013 reflect the seasonal, weather-related variations in NGL sales. Our guidance is also based on an expectation that domestic oil production will continue to increase in line with increases over the last couple of years. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast adjusted 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. Actual volumes are influenced by maintenance schedules at refineries, actual production levels, 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. For the last nine months of 2013 we expect adjusted segment profit to be lower as compared to our forecast for the three month period ending March 31, 2013 as pipeline infrastructure is completed and placed into service.

	Guidance	
	Three Months Ending Mar 31, 2013	Twelve Months Ending Dec 31, 2013
Average Daily Volumes (MBbl/d)		
Crude Oil Lease Gathering Purchases	850	900
NGL Sales	270	190
Waterborne cargos	5	5
	1,125	1,095
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability	$ 2.83[1]	$ 1.49[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 may vary due to gains and losses on intermittent sales of assets, asset retirement obligations, asset impairments or foreign exchange rates.

4. *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 we may commit to after the date hereof. We forecast capital expenditures during calendar 2013 to be approximately $1.1 billion for expansion projects with an additional $160 to $180 million for maintenance capital projects. The following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2013:

	Calendar 2013 (in millions)
Expansion Capital	
· Mississippian Lime Pipeline	$150
· Rainbow II Pipeline	135
· White Cliffs Expansion	90
· Gulf Coast Pipeline	80
· Yorktown Terminal Projects	75
· Eagle Ford Area Pipeline Projects	75
· Eagle Ford JV Project	65
· St. James Terminal Projects	55
· PAA Natural Gas Storage (Multiple Projects)	42
· Spraberry Area Pipeline Projects	40
· Tampa, CO Rail Terminal	35
· Bakersfield, CA Rail Terminal	35
· Shafter Expansion	25
· Cushing Terminal Projects	20
· Other Projects [1]	178
	$1,100
Potential Adjustments for Timing / Scope Refinement [2]	- $50 + $100
Total Projected Expansion Capital Expenditures	$1050 - $1,200
Maintenance Capital Expenditures	$160 - $180

(1) Primarily multiple, smaller projects comprised of pipeline connections, upgrades and truck stations, new tank construction and refurbishing, pipeline linefill purchases and carry-over of projects from prior years.

(2) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as permits, regulatory approvals and weather.

5. *Capital Structure.* This guidance is based on our capital structure as of December 31, 2012, adjusted for estimated equity issuances under our continuous offering program and assuming the repayment of our $250 million

5.625% senior notes that mature December 15, 2013 with short-term borrowings from our credit facility as a result of prefunding during 2012 (equity, retained cash flow, and senior note issuance).

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated 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 NGL inventory and New York Mercantile Exchange and Intercontinental Exchange 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 hedged inventory borrowings as carrying costs of crude oil and NGL and include it in purchases and related costs.

7. *Income Taxes*. We expect Canadian income tax expense to be approximately $27 million and $58 million for the three-month period ending March 31, 2013 and twelve-month period ending December 31, 2013, respectively, of which approximately $23 million and $45 million, respectively, is classified as current. For the twelve-month period ending December 31, 2013 we expect to have a deferred tax expense of $13 million. All or part of the income tax expense of $58 million may result in a tax credit to our equity holders.

8. *Implied DCF.* The following table calculates implied distributable cash flow for the three-month period ending March 31, 2013 and the twelve-month period ending December 31, 2013.

	Mid-Point Guidance	
	Three Months Ending March 31, 2013	Twelve Months Ending December 31, 2013
Adjusted EBITDA	$ 615	$ 2,025
Interest expense, net	(79)	(325)
Current income tax expense	(23)	(45)
Distributions to noncontrolling interests	(12)	(48)
Maintenance capital expenditures	(43)	(170)
Implied DCF	$ 458	$ 1,437

9. *Equity Compensation Plans.* The majority of grants outstanding under our various equity compensation plans contain vesting criteria that are based on a combination of performance benchmarks and service periods. The grants will vest in various percentages, typically on the later to occur of specified vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of February 5, 2013, estimated vesting dates range from February 2013 to May 2019 and annualized benchmark distribution levels range from $1.925 to $2.40. For some awards, a percentage of any units remaining unvested as of a certain date will vest on such date and all others will be forfeited.

   On January 7, 2013, we declared an annualized distribution of $2.25 payable on February 14, 2013 to our unitholders of record as of February 1, 2013. For the purposes of guidance, we have made the assessment that a $2.45 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $50.00 per unit as well as an accrual associated with awards that will vest on a certain date. The actual amount of equity compensation expense 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 vesting date, (iii) the probability assessment regarding distributions, and (iv) new equity compensation award grants. For example, a $2.00 change in the unit price would change the first-quarter and full-year equity compensation expense by approximately $5 million and $6 million, respectively. Therefore, actual net income could differ from our projections.

10. *Reconciliation of Net Income to EBIT, EBITDA and Adjusted EBITDA.* The following table reconciles net income to EBIT, EBITDA and Adjusted EBITDA for the three-month period ending March 31, 2013 and the twelve-month period ending December 31, 2013.

	Guidance			
	3 Months Ending March 31, 2013		12 Months Ending December 31, 2013	
	Low	High	Low	High
Reconciliation to EBITDA				
Net Income	$ 376	$ 438	$ 1,180	$ 1,310
Interest expense, net	81	77	330	320
Income tax expense (benefit)	29	25	63	53
EBIT	486	540	1,573	1,683
Depreciation and amortization	86	82	353	343
EBITDA	$ 572	$ 622	$ 1,926	$ 2,026
Selected Items Impacting Comparability of EBITDA	(18)	(18)	(49)	(49)
Adjusted EBITDA	**$ 590**	**$ 640**	**$ 1,975**	**$ 2,075**

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 incorporating the words “anticipate,” “believe,” “estimate,” “expect,” “plan,” “intend” and “forecast,” as well as similar expressions and statements regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results or outcomes to differ materially from results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

· failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects;

· unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

· 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;

· the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;

- tightened capital markets or other factors that increase our cost of capital or limit our access to capital;
- 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 effectiveness of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to or slowdown in the development of additional oil and gas reserves or other factors;
- shortages or cost increases of supplies, materials or labor;
- 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 impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- non-utilization of our assets and facilities;
- the effects of competition;
- interruptions in service 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;
- factors affecting demand for natural gas and natural gas storage services and rates;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

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: February 6, 2013

By: /s/ Charles Kingswell-Smith

Name:	Charles Kingswell-Smith
Title:	*Vice President and Treasurer*

Exhibit 99.1

FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports Strong
Fourth-Quarter and Full-Year 2012 Results

(Houston — February 6, 2013) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income attributable to Plains of $320 million, or $0.69 per diluted limited partner unit, for the fourth quarter of 2012, and net income attributable to Plains of $1.09 billion, or $2.40 per diluted limited partner unit, for the full year of 2012. Net income attributable to Plains for the fourth quarter of 2011 was $278 million, or $0.68 per diluted limited partner unit, and net income attributable to Plains for the full year of 2011 was $966 million, or $2.44 per diluted limited partner unit. The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $541 million and $1.95 billion for the fourth quarter and full year of 2012, respectively. The comparable amounts for the fourth quarter and full year of 2011 were $426 million and $1.54 billion, respectively.

The Partnership's reported results include the impact of items that affect comparability between reporting periods. Items impacting comparability are excluded from adjusted results as detailed in the table below. Accordingly, the Partnership's fourth-quarter 2012 adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA were $429 million, $1.01 and $609 million, respectively. The comparable amounts for the fourth quarter of 2011 were $322 million, $0.82 and $471 million, respectively.

The Partnership's adjusted net income attributable to Plains, adjusted net income per diluted limited partner unit and adjusted EBITDA for the full year of 2012 were $1.41 billion, $3.35 and $2.11 billion, respectively. The comparable amounts for the full year of 2011 were $1.02 billion, $2.62 and $1.60 billion, 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 their reconciliation to the most directly comparable GAAP measures.)

"PAA generated exceptional results for the fourth quarter and full year of 2012," said Greg L. Armstrong, Chairman and CEO of Plains All American. "Our fee-based Transportation and Facilities segments delivered results in line with or ahead of guidance throughout the year as demand for our services remained strong and new capital projects were placed into service. Our Supply and Logistics segment substantially exceeded our guidance on the strength of increasing volumes, attractive margins, favorable market conditions and solid execution."

"During 2012, PAA invested $3.5 billion of total capital, including $1.2 billion in organic growth projects and $2.3 billion in strategic and complementary acquisitions. Importantly, as a result of PAA's disciplined and proactive financing efforts, the Partnership entered 2013 with a strong balance sheet, $2.4 billion of committed liquidity and very well positioned to execute its growth objectives while maintaining a solid credit profile."

"Expected contributions from investments made over the last few years combined with the $1.1 billion of planned organic growth capital for 2013 provide substantial visibility for continued baseline growth in 2013 and beyond. This visibility underpins our favorable outlook for continued attractive distribution growth. In that regard, concurrent with our distribution payable next week, we will have increased our distributions by 9.8% over the distribution paid in February 2012, and we are targeting 9 to 10% year-over-year distribution growth in 2013, while maintaining very attractive distribution coverage."

-more-

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 December 31,		Twelve Months Ended December 31,	
	2012	**2011**	**2012**	**2011**
Selected Items Impacting Comparability - Income/(Loss) (1):				
Gains/(losses) from derivative activities net of inventory valuation adjustments (2)	$ (56)	$ (11)	$ (74)	$ 61
Asset impairments (3)	(41)	—	(166)	—
Equity compensation expense (4)	(10)	(37)	(59)	(77)
Net loss on early repayment of senior notes	—	—	—	(23)
Net gain/(loss) on foreign currency revaluation	(1)	10	(7)	(7)
Significant acquisition-related expenses	(1)	(6)	(14)	(10)
Other (5)	—	—	—	1
Selected items impacting comparability of net income attributable to Plains	$ (109)	$ (44)	$ (320)	$ (55)
Impact to basic net income per limited partner unit	$ (0.31)	$ (0.14)	$ (0.96)	$ (0.18)
Impact to diluted net income per limited partner unit	$ (0.32)	$ (0.14)	$ (0.95)	$ (0.18)

(1) Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

(2) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period net of inventory valuation adjustments.
(3) Asset impairments are reflected in "Depreciation and amortization" on the Consolidated Statements of Operations.
(4) Equity compensation expense for the three and twelve months ended December 31, 2012 and 2011 excludes the portion of equity compensation expense represented by grants under Long-term Incentive Plans ("LTIPs") that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units.
(5) Includes other immaterial selected items impacting comparability, as well as the noncontrolling interests' portion of selected items.

-more-

The following tables present certain selected financial information by segment for the fourth-quarter (amounts in millions):

	Three Months Ended December 31, 2012			Three Months Ended December 31, 2011		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 373	$ 313	$ 9,072	$ 301	$ 280	$ 8,501
Purchases and related costs [1]	(34)	(70)	(8,724)	(27)	(118)	(8,190)
Field operating costs (excluding equity compensation expense) [1]	(126)	(85)	(110)	(93)	(43)	(89)
Equity compensation expense - operations	(3)	—	—	(9)	(1)	(1)
Segment G&A expenses (excluding equity compensation expense) [2]	(22)	(16)	(24)	(20)	(11)	(20)
Equity compensation expense - general and administrative	(7)	(4)	(5)	(17)	(8)	(18)
Equity earnings in unconsolidated entities	12	—	—	4	—	—
Reported segment profit	$ 193	$ 138	$ 209	$ 139	$ 99	$ 183
Selected items impacting comparability of segment profit [3]	5	3	58	21	8	17
Segment profit excluding selected items impacting comparability	$ 198	$ 141	$ 267	$ 160	$ 107	$ 200
Maintenance capital	$ 30	$ 16	$ 2	$ 34	$ 6	$ 3

	Twelve Months Ended December 31, 2012			Twelve Months Ended December 31, 2011		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 1,416	$ 1,098	$ 36,440	$ 1,165	$ 796	$ 33,068
Purchases and related costs [1]	(134)	(238)	(35,139)	(115)	(205)	(31,984)
Field operating costs (excluding equity compensation expense) [1]	(468)	(289)	(417)	(387)	(165)	(314)
Equity compensation expense - operations	(16)	(2)	(2)	(14)	(2)	(2)
Segment G&A expenses (excluding equity compensation expense) [2]	(96)	(64)	(101)	(69)	(47)	(86)
Equity compensation expense - general and administrative	(30)	(23)	(28)	(38)	(19)	(35)
Equity earnings in unconsolidated entities	38	—	—	13	—	—
Reported segment profit	$ 710	$ 482	$ 753	$ 555	$ 358	$ 647
Selected items impacting comparability of segment profit [3]	32	20	102	40	23	(34)
Segment profit excluding selected items impacting comparability	$ 742	$ 502	$ 855	$ 595	$ 381	$ 613
Maintenance capital	$ 108	$ 49	$ 13	$ 86	$ 22	$ 12

(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. Includes acquisition-related expenses for both the 2012 and 2011 periods.
(3) Certain non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

-more-

Adjusted Transportation segment profit for both the fourth quarter and full year of 2012 increased by approximately 25% over comparable 2011 results. The increase in these periods was primarily driven by the benefit of the BP NGL acquisition as well as recently completed organic growth projects, increased pipeline volumes and higher average pipeline tariffs.

Adjusted Facilities segment profit for both the fourth quarter and full year of 2012 increased by approximately 32% over comparable 2011 results. The increase in these periods was primarily related to capacity additions from the BP NGL acquisition and organic growth projects.

Adjusted Supply and Logistics segment profit for the fourth quarter and full year of 2012 increased by approximately 34% and 39%, respectively, over comparable 2011 results. The fourth-quarter increase was primarily related to the solid execution of PAA's business model during favorable crude oil market conditions and increased NGL sales volumes. The full-year increase was primarily related to increased crude oil lease gathering volumes and margins as well as favorable crude oil market conditions.

The Partnership's basic weighted average units outstanding for the fourth quarter of 2012 was 334 million units (337 million diluted units) as compared to 305 million units (308 million diluted units) in last year's fourth quarter. At year-end 2012, the Partnership had approximately 335.3 million units outstanding, long-term debt of approximately $6.3 billion and a long-term debt-to-total capitalization ratio of 47%.

The Partnership has declared a quarterly distribution of $0.5625 per unit ($2.25 per unit on an annualized basis) payable February 14, 2013 on its outstanding limited partner units. This distribution represents an increase of approximately 9.8% over the quarterly distribution paid in February 2012 and an increase of approximately 3.7% over the quarterly distribution paid in November 2012.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future. These measures include adjusted EBITDA and implied distributable cash flow ("DCF"). Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), net of inventory valuation adjustments, (iii) items that are not indicative of our core operating results and business outlook, and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items as "Selected Items Impacting Comparability." These additional financial measures are reconciled from the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

-more-

Although we present selected items that we consider in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions and numerous other factors. A full analysis of 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 Annual Report on Form 10-K.

A reconciliation of EBITDA to net income and EBITDA to cash flows from operating activities for the periods presented are 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 Reconciliations" link on the Investor Relations page.

Conference Call

The Partnership will host a conference call at 10 a.m. CST on Thursday, February 7, 2013 to discuss the following items:

1. The Partnership's fourth-quarter and full-year 2012 performance;

2. The status of major expansion projects;

3. Capitalization and liquidity;

4. Financial and operating guidance for the first quarter and full year of 2013; and

5. The Partnership's outlook for the future.

Prior to this 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 first quarter and full year of 2013. A copy of the Form 8-K will be available on the Partnership's 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." Following the live webcast, the call will be archived for a period of sixty (60) days on the Partnership's website.

Alternatively, dial (800) 288-8967 to access the live conference call. International callers should dial (612) 332-0636. No password is required. Access to the slide presentation accompanying the conference call is available 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 utilize the following replay access code: 277242. The replay will be available beginning Thursday February 7, 2013, at approximately noon CST and continue until 11:59 p.m. CST Friday, March 7, 2013.

-more-

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 or outcomes to differ materially from results or outcomes anticipated in the forward-looking statements. These risks and uncertainties include, among other things, failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects; unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof); the availability of, and our ability to consummate, acquisition or combination opportunities; 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; the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems; tightened capital markets or other factors that increase our cost of capital or limit our access to capital; 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 effectiveness of our risk management activities; environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves; declines in the volume of crude oil, natural gas, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to or slowdown in the development of additional oil and gas reserves or other factors; shortages or cost increases of supplies, materials or labor; 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; 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 impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations; non-utilization of our assets and facilities; the effects of competition; interruptions in service 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; factors affecting demand for natural gas and natural gas storage services and rates; general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids discussed in the Partnership's filings with the Securities and Exchange Commission.

Plains All American Pipeline, L.P. is a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids. Through its general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), PAA owns and operates natural gas storage facilities. PAA is headquartered in Houston, Texas.

-more-

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

CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	**2011**	**2012**	**2011**
REVENUES	$ 9,439	$ 8,884	$ 37,797	$ 34,275
COSTS AND EXPENSES				

Purchases and related costs	8,513	8,141	34,368	31,564
Field operating costs	320	232	1,180	870
General and administrative expenses	78	94	342	294
Depreciation and amortization	126	58	482	249
Total costs and expenses	9,037	8,525	36,372	32,977
OPERATING INCOME	402	359	1,425	1,298
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	12	4	38	13
Interest expense	(74)	(63)	(288)	(253)
Other income/(expense), net	1	5	6	(19)
INCOME BEFORE TAX	341	305	1,181	1,039
Current income tax expense	(21)	(13)	(53)	(38)
Deferred income tax benefit/(expense)	10	(4)	(1)	(7)
NET INCOME	330	288	1,127	994
Net income attributable to noncontrolling interests	(10)	(10)	(33)	(28)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 320	$ 278	$ 1,094	$ 966
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 234	$ 210	$ 789	$ 730
GENERAL PARTNER	$ 86	$ 68	$ 305	$ 236
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.70	$ 0.69	$ 2.41	$ 2.46
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.69	$ 0.68	$ 2.40	$ 2.44
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	334	305	325	297
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	337	308	328	299

-more-

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2012	2011	2012	2011
OPERATING DATA [(1)]				
Transportation activities (average daily volumes in thousands of barrels) [(2)]**:**				
Crude Oil Pipelines				
All American	37	34	33	35
Bakken Area Systems	120	135	130	130
Basin / Mesa	756	586	696	566
Capline	154	145	146	160
Eagle Ford Area Systems	40	4	23	5
Line 63/Line 2000	134	113	128	114
Manito	52	67	57	66
Mid-Continent Area Systems	256	201	249	213
Permian Basin Area Systems	489	412	461	404
Rainbow	141	152	145	142
Rangeland	65	63	62	59
Salt Lake City Area Systems	144	141	149	146
White Cliffs	21	15	18	13
Other	802	824	785	787
NGL Pipelines				
Co-Ed	52	—	44	—
Other	159	—	131	—
Refined Products Pipelines	122	110	116	102
Tariff activities total	3,544	3,002	3,373	2,942
Trucking	112	109	106	105
Transportation activities total	3,656	3,111	3,479	3,047

Facilities activities (average monthly volumes):				
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	73	90	70
Natural gas storage (average monthly capacity in billions of cubic feet)	93	76	84	71
NGL fractionation (average throughput in thousands of barrels per day)	97	14	79	14
Facilities activities total (average monthly capacity in millions of barrels) [3]	113	86	106	82
Supply and Logistics activities (average daily volumes in thousands of barrels):				
Crude oil lease gathering purchases	850	776	818	742
NGL sales	259	118	182	103
Waterborne cargos	4	—	3	21
Supply and Logistics activities total	1,113	894	1,003	866

---

(1) Volumes associated with acquisitions represent total volumes (attributable to our interest) for the number of days or months we actually owned the assets divided by the number of days or months in the period.

(2) As of December 31, 2012, we revised the summary presentation of our volumes related to our transportation activities. All prior year volumes have been restated herein to reflect such updates.

(3) Facilities total is calculated as the sum of: (i) crude oil, refined products and NGL storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) NGL fractionation volumes (based on estimated utilized capacity) multiplied by the number of days in the period and divided by the number of months in the period.

-more-

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(in millions)

	December 31, 2012	December 31, 2011
ASSETS		
Current assets	$ 5,147	$ 4,351
Property and equipment, net	9,643	7,740
Goodwill	2,535	1,854
Linefill and base gas	707	564
Long-term inventory	274	135
Investments in unconsolidated entities	343	191
Other, net	586	546
Total assets	$ 19,235	$ 15,381
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 5,183	$ 4,511
Senior notes, net of unamortized discount	6,010	4,262
Long-term debt under credit facilities and other	310	258
Other long-term liabilities and deferred credits	586	376
Total liabilities	12,089	9,407
Partners' capital excluding noncontrolling interests	6,637	5,450
Noncontrolling interests	509	524
Total partners' capital	7,146	5,974
Total liabilities and partners' capital	$ 19,235	$ 15,381

-more-

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

FINANCIAL SUMMARY (unaudited)

CREDIT RATIOS
(in millions)

	December 31, 2012	December 31, 2011
Short-term debt	$ 1,086	$ 679
Long-term debt	6,320	4,520
Total debt	$ 7,406	$ 5,199
Long-term debt	6,320	4,520
Partners' capital	7,146	5,974
Total book capitalization	$ 13,466	$ 10,494
Total book capitalization, including short-term debt	$ 14,552	$ 11,173
Long-term debt-to-total book capitalization	47%	43%
Total debt-to-total book capitalization, including short-term debt	51%	47%

-more-

333 Clay Street, Suite 1600 Houston, Texas 77002 713-646-4100 / 800-564-3036

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 December 31,		Twelve Months Ended December 31,	
	2012	2011	2012	2011
Basic Net Income per Limited Partner Unit:				
Net income attributable to Plains	$ 320	$ 278	$ 1,094	$ 966
Less: General partner's incentive distribution [1]	(81)	(63)	(289)	(221)
Less: General partner 2% ownership [1]	(5)	(5)	(16)	(15)
Net income available to limited partners	234	210	789	730
Less: Undistributed earnings allocated and distributions to participating securities [1]	(1)	—	(5)	—
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 233	$ 210	$ 784	$ 730
Basic weighted average number of limited partner units outstanding	334	305	325	297
Basic net income per limited partner unit	$ 0.70	$ 0.69	$ 2.41	$ 2.46
Diluted Net Income per Limited Partner Unit:				
Net income attributable to Plains	$ 320	$ 278	$ 1,094	$ 966
Less: General partner's incentive distribution [1]	(81)	(63)	(289)	(221)
Less: General partner 2% ownership [1]	(5)	(5)	(16)	(15)
Net income available to limited partners	234	210	789	730
Less: Undistributed earnings allocated and distributions to participating securities [1]	(1)	—	(4)	—
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 233	$ 210	$ 785	$ 730
Basic weighted average number of limited partner units outstanding	334	305	325	297
Effect of dilutive securities: Weighted average LTIP units [2]	3	3	3	2
Diluted weighted average number of limited partner units outstanding	337	308	328	299
Diluted net income per limited partner unit	$ 0.69	$ 0.68	$ 2.40	$ 2.44

[1] We calculate net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

[2] Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

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

FINANCIAL DATA RECONCILIATIONS
(in millions)

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Net income to earnings before interest, taxes, depreciation and amortization (“EBITDA”) and excluding selected items impacting comparability (“Adjusted EBITDA”) reconciliations				
Net Income	$ 330	$ 288	$ 1,127	$ 994
Add: Interest expense	74	63	288	253
Add: Income tax expense	11	17	54	45
Add: Depreciation and amortization	126	58	482	249
EBITDA	$ 541	$ 426	$ 1,951	$ 1,541
Selected items impacting comparability of EBITDA [1]	68	45	156	57
Adjusted EBITDA	$ 609	$ 471	$ 2,107	$ 1,598

[1] Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Adjusted EBITDA to Implied Distributable Cash Flow (“DCF”)				
Adjusted EBITDA	$ 609	$ 471	$ 2,107	$ 1,598
Interest expense	(74)	(63)	(288)	(253)
Maintenance capital	(48)	(43)	(170)	(120)
Current income tax expense	(21)	(13)	(53)	(38)
Equity earnings in unconsolidated entities, net of distributions	1	3	2	10
Distributions to noncontrolling interests [1]	(12)	(12)	(48)	(47)
Other	—	—	—	(1)
Implied DCF	$ 455	$ 343	$ 1,550	$ 1,149

[1] Includes distributions that pertain to the current period’s net income, a portion of which are to be paid in the subsequent period.

	Three Months Ended December 31, 2012	Three Months Ended December 31, 2011	Twelve Months Ended December 31, 2012	Twelve Months Ended December 31, 2011
Cash flow from operating activities reconciliation				
EBITDA	$ 541	$ 426	$ 1,951	$ 1,541
Current income tax expense	(21)	(13)	(53)	(38)
Interest expense	(74)	(63)	(288)	(253)
Net change in assets and liabilities, net of acquisitions	(104)	201	(471)	1,005
Other items to reconcile to cash flows from operating activities:				
Equity compensation expense	19	54	101	110
Net cash provided by operating activities	$ 361	$ 605	$ 1,240	$ 2,365

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

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

Three Months Ended Twelve Months Ended

	December 31,		December 31,	
	2012	2011	2012	2011
Basic Adjusted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 320	$ 278	$ 1,094	$ 966
Selected items impacting comparability of net income attributable to Plains	109	44	320	55
Adjusted net income attributable to Plains	429	322	1,414	1,021
Less: General partner's incentive distribution [1]	(81)	(63)	(289)	(221)
Less: General partner 2% ownership [1]	(7)	(6)	(23)	(16)
Adjusted net income available to limited partners	341	253	1,102	784
Less: Undistributed earnings allocated and distributions to participating securities [1]	(3)	—	(8)	—
Adjusted limited partners' net income	$ 338	$ 253	$ 1,094	$ 784
Basic weighted average number of limited partner units outstanding	334	305	325	297
Basic adjusted net income per limited partner unit	$ 1.01	$ 0.83	$ 3.37	$ 2.64
Diluted Adjusted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 320	$ 278	$ 1,094	$ 966
Selected items impacting comparability of net income attributable to Plains	109	44	320	55
Adjusted net income attributable to Plains	429	322	1,414	1,021
Less: General partner's incentive distribution [1]	(81)	(63)	(289)	(221)
Less: General partner 2% ownership [1]	(7)	(6)	(23)	(16)
Adjusted net income available to limited partners	341	253	1,102	784
Less: Undistributed earnings allocated and distributions to participating securities [1]	(1)	—	(4)	—
Adjusted limited partners' net income	$ 340	$ 253	$ 1,098	$ 784
Diluted weighted average number of limited partner units outstanding	337	308	328	299
Diluted adjusted net income per limited partner unit	$ 1.01	$ 0.82	$ 3.35	$ 2.62

[1] We calculate adjusted net income available to limited partners based on the distributions pertaining to the current period's net income. After adjusting for the appropriate period's distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

Contacts:

Roy I. Lamoreaux
Director, Investor Relations
(713) 646-4222 — (800) 564-3036

Al Swanson
Executive Vice President, CFO
(800) 564-3036

###