

**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported) — **August 5, 2013**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE

(State or other jurisdiction of
incorporation)

1-14569

(Commission File Number)

76-0582150

(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:

- Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

- (d) Exhibit 99.1 — Press Release dated August 5, 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 second-quarter 2013 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 also providing detailed guidance for financial performance for the third and fourth quarters and full year of 2013. 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 Third and Fourth Quarter 2013 Guidance; Update of Full Year 2013 Guidance

We based our guidance for the three-month period ending September 30, 2013 and three-month and twelve-month periods 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 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 August 4, 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 9 below, we reconcile net income to EBIT and EBITDA for the 2013 guidance periods presented. Cash flows 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 forecasted periods. 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 (i) equity-indexed compensation expense, (ii) tax effect on selected items impacting comparability, (iii) net gain on foreign currency revaluation, (iv) gains/(losses) from derivative activities and (v) other selected items impacting comparability. Due to the nature of the selected items, certain selected items impacting comparability may impact certain non-GAAP financial measures but not impact other non-GAAP financial measures.

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

	Actual		Guidance ^(a)					
	6 Months Ended June 30, 2013	3 Months Ending September 30, 2013		3 Months Ending December 31, 2013		12 Months Ending December 31, 2013		
			Low	High	Low	High	Low	High
Segment Profit								
Net revenues (including equity earnings from unconsolidated entities)	\$ 2,113	\$ 820	\$ 855	\$ 908	\$ 943	\$ 3,841	\$ 3,911	
Field operating costs	(684)	(344)	(334)	(320)	(310)	(1,348)	(1,328)	
General and administrative expenses	(196)	(86)	(81)	(84)	(79)	(366)	(356)	
	1,233	390	440	504	554	2,127	2,227	
Depreciation and amortization expense	(173)	(91)	(86)	(92)	(87)	(356)	(346)	
Interest expense, net	(152)	(84)	(80)	(85)	(81)	(321)	(313)	
Income tax expense	(70)	(11)	(7)	(23)	(19)	(104)	(96)	
Other income / (expense), net	(1)	1	1	1	1	1	1	
Net Income	837	205	268	305	368	1,347	1,473	
Net income attributable to noncontrolling interests	(16)	(6)	(6)	(9)	(9)	(31)	(31)	
Net Income Attributable to Plains	\$ 821	\$ 199	\$ 262	\$ 296	\$ 359	\$ 1,316	\$ 1,442	
Net Income to Limited Partners ^(b)	\$ 631	\$ 101	\$ 163	\$ 191	\$ 253	\$ 923	\$ 1,047	
Basic Net Income Per Limited Partner Unit ^(b)								
Weighted Average Units Outstanding	338	343	343	345	345	341	341	
Net Income Per Unit	\$ 1.85	\$ 0.29	\$ 0.47	\$ 0.55	\$ 0.73	\$ 2.69	\$ 3.05	
Diluted Net Income Per Limited Partner Unit ^(b)								
Weighted Average Units Outstanding	341	345	345	347	347	344	344	
Net Income Per Unit	\$ 1.84	\$ 0.29	\$ 0.47	\$ 0.54	\$ 0.72	\$ 2.67	\$ 3.03	
EBIT	\$ 1,059	\$ 300	\$ 355	\$ 413	\$ 468	\$ 1,772	\$ 1,882	
EBITDA	\$ 1,232	\$ 391	\$ 441	\$ 505	\$ 555	\$ 2,128	\$ 2,228	
Selected Items Impacting Comparability								
Equity-indexed compensation expense	\$ (39)	\$ (14)	\$ (14)	\$ (13)	\$ (13)	\$ (66)	\$ (66)	
Tax effect on selected items impacting comparability	(6)	—	—	—	—	(6)	(6)	
Net gain on foreign currency revaluation	4	—	—	—	—	4	4	
Gains/(losses) from derivative activities	50	—	—	—	—	50	50	
Other	1	1	1	—	—	2	2	
Selected Items Impacting Comparability of Net Income attributable to Plains	\$ 10	\$ (13)	\$ (13)	\$ (13)	\$ (13)	\$ (16)	\$ (16)	
Excluding Selected Items Impacting Comparability								
Adjusted Segment Profit								
Transportation	\$ 341	\$ 199	\$ 209	\$ 222	\$ 232	\$ 762	\$ 782	
Facilities	310	130	140	150	160	590	610	
Supply and Logistics	561	75	105	145	175	781	841	
Other income, net	5	1	1	1	1	7	7	
Adjusted EBITDA	\$ 1,217	\$ 405	\$ 455	\$ 518	\$ 568	\$ 2,140	\$ 2,240	
Adjusted Net Income Attributable to Plains	\$ 811	\$ 212	\$ 275	\$ 319	\$ 372	\$ 1,332	\$ 1,458	
Basic Adjusted Net Income Per Limited Partner Unit ^(b)	\$ 1.83	\$ 0.33	\$ 0.51	\$ 0.58	\$ 0.76	\$ 2.74	\$ 3.10	
Diluted Adjusted Net Income Per Limited Partner Unit ^(b)	\$ 1.82	\$ 0.33	\$ 0.51	\$ 0.57	\$ 0.75	\$ 2.72	\$ 3.08	

^(a) The projected average foreign exchange rate is \$1.00 Canadian to \$1.00 U.S. for the three-month periods ending September 30, 2013 and December 31, 2013. The rate as of August 2, 2013 was \$1.00 Canadian to \$0.96 U.S. A \$0.05 change in the FX rate will impact annual adjusted EBITDA by approximately \$12 million.

^(b) 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.

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Notes and Significant Assumptions:

1. Definitions.

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
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" or "GP" 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 and NGL on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and other 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, anticipated future operating performance and assumed completion of internal growth projects. Actual volumes will be influenced by maintenance schedules at refineries, production trends, weather and other natural occurrences, 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.

	Actual		Guidance	
	Six Months Ended Jun 30, 2013	Three Months Ending Sep 30, 2013	Three Months Ending Dec 31, 2013	Twelve Months Ending Dec 31, 2013
Average Daily Volumes (MBbls/d)				
Crude Oil / Refined Products Pipelines				
All American	39	40	40	40
Bakken Area Systems	127	130	135	130
Basin/Mesa	702	700	675	695
Capline	157	160	160	159
Eagle Ford Area Systems	61	130	195	112
Line 63 / 2000	113	105	105	109
Manito	46	45	45	45
Mid-Continent Area Systems	261	270	285	269
Permian Basin Area Systems	513	605	675	577
Rainbow	124	125	125	125
Rangeland	62	60	60	61
Salt Lake City Area Systems	133	145	140	138
South Saskatchewan	46	55	55	51
White Cliffs	21	25	25	23
Other	868	835	760	832
NGL Pipelines				
Co-Ed	54	55	55	55
Other	186	170	165	177
	3,513	3,655	3,700	3,598
Trucking	109	110	110	110
	3,622	3,765	3,810	3,708
Segment Profit per Barrel (\$/Bbl)				
Excluding Selected Items Impacting Comparability	\$ 0.52	\$ 0.59 ⁽¹⁾	\$ 0.65 ⁽¹⁾	\$ 0.57 ⁽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, natural gas and NGL, NGL fractionation and isomerization services and natural gas and condensate processing 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) terminal 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 rail terminals, (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 and condensate 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.

	<u>Actual</u>		<u>Guidance</u>	
	Six Months Ended Jun 30, 2013		Three Months Ending Sep 30, 2013	Three Months Ending Dec 31, 2013
Operating Data				
Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)	94	95	96	95
Rail Load / Unload Volumes (MBbl/d)	223	250	305	250
Natural Gas Storage (Bcf/Mo.)	95	97	97	96
NGL Fractionation (MBbls/d)	95	100	110	100
Facilities Activities Total				
Avg. Capacity (MMBbls/Mo.) ⁽¹⁾	120	122	125	122
Segment Profit per Barrel (\$/Bbl)				
Excluding Selected Items Impacting Comparability	\$ 0.43	\$ 0.37 ⁽²⁾	\$ 0.41 ⁽²⁾	\$ 0.41 ⁽²⁾

- (1) Calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes, 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, 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 merchant-related 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 from various delivery points to market hub locations or directly to end users such as refineries, processors and fractionation facilities.

We characterize a substantial portion of our baseline 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 September 30, 2013 reflect the current market structure and for the last six months of 2013 reflect the seasonal, weather-related variations in NGL sales. Our second-half guidance reflects an expectation for less favorable crude oil market conditions than those experienced during the first half of the year. 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 temporary market-driven storage and withdrawal of oil, 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 and quality differentials as well as contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	<u>Actual</u>		<u>Guidance</u>	
	Six Months Ended Jun 30, 2013		Three Months Ending Sep 30, 2013	Three Months Ending Dec 31, 2013
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering Purchases	855	860	880	863
NGL Sales	221	125	235	200
Waterborne Cargos	6	5	5	5
	1,082	990	1,120	1,068
Segment Profit per Barrel (\$/Bbl)				
Excluding Selected Items Impacting Comparability	\$ 2.86	\$ 0.99 ⁽¹⁾	\$ 1.55 ⁽¹⁾	\$ 2.08 ⁽¹⁾

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 \$1.6 billion for expansion projects with an additional \$175 to \$195 million for maintenance capital projects. During the first six months of 2013, we invested \$830 million and \$82 million for expansion and maintenance projects, respectively. The following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2013:

	<u>Calendar 2013</u> <u>(in millions)</u>
Expansion Capital	
· Mississippian Lime Pipeline	\$170
· Rainbow II Pipeline	135
· Yorktown Terminal Projects	100
· Gulf Coast Pipeline	95
· Eagle Ford Area Pipeline Projects	90
· White Cliffs Expansion	90
· Rail Terminal Projects ⁽¹⁾	80
· Cactus Pipeline	75
· Fort Saskatchewan Facility Expansions	75
· Eagle Ford JV Project	70
· St. James Terminal Projects	55
· Western Oklahoma Extension	45
· PAA Natural Gas Storage (Multiple Projects)	44
· Spraberry Area Pipeline Projects	40
· Gulf Coast Gas Processing Facility Enhancements	35
· Cushing Terminal Projects	30
· Shafter Expansion	25
· Other Projects ⁽²⁾	346
	<u>\$1,600</u>
Potential Adjustments for Timing / Scope Refinement ⁽³⁾	<u>- \$50 + \$100</u>
Total Projected Expansion Capital Expenditures	<u>\$1,550 - \$1,700</u>
Maintenance Capital Expenditures	\$175 - \$195

(1) Includes projects located at or near Tampa, CO, Bakersfield, CA and Van Hook, ND.

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

(3) 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 June 30, 2013 and adjusted for estimated equity issuances under our continuous offering program. Also assumed in our guidance is that we expect to repay 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 and retained cash flow), accordingly these notes are classified as short-term on our balance sheet at June 30, 2013.
6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated capital expenditures for maintenance and expansion projects, anticipated equity proceeds from the continuous offering program, 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 LIBOR curve as of late July.

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 our Canadian income tax expense to be approximately \$9 million and \$100 million for the three-month period ending September 30, 2013 and twelve-month period ending December 31, 2013, respectively, of which approximately \$2 million and \$69 million, respectively, is classified as current income tax expense. For the twelve-month period ending December 31, 2013 we expect to have deferred tax expense of \$31 million. All or part of the income tax expense of \$100 million may result in a tax credit to our equity holders.

8. *Equity-Indexed Compensation Plans.* The majority of grants outstanding under our various equity-indexed 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 August 5, 2013, estimated vesting dates range from August 2013 to August 2019 and annualized benchmark distribution levels range from \$1.925 to \$2.85. 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 July 8, 2013, we declared an annualized distribution of \$2.35 payable on August 14, 2013 to our unitholders of record as of August 2, 2013. For the purposes of guidance, we have made the assessment that a \$2.50 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of \$56.00 per unit as well as an accrual associated with awards that will vest on a certain date. The actual amount of equity-indexed 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-indexed compensation award grants. For example, a \$2.00 change in the unit price would change both the third-quarter and full-year equity-indexed compensation expense by approximately \$4 million. Therefore, actual net income could differ from our projections.

9. *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 September 30, 2013 and the three-month and twelve-month periods ending December 31, 2013.

	Guidance					
	3 Months Ending September 30, 2013		3 Months Ending December 31, 2013		12 Months Ending December 31, 2013	
	Low	High	Low	High	Low	High
Reconciliation to EBITDA						
Net Income	\$ 205	\$ 268	\$ 305	\$ 368	\$ 1,347	\$ 1,473
Interest expense, net	84	80	85	81	321	313
Income tax expense	11	7	23	19	104	96
EBIT	300	355	413	468	1,772	1,882
Depreciation and amortization	91	86	92	87	356	346
EBITDA	\$ 391	\$ 441	\$ 505	\$ 555	\$ 2,128	\$ 2,228
Selected Items Impacting Comparability of EBITDA	14	14	13	13	12	12
Adjusted EBITDA	\$ 405	\$ 455	\$ 518	\$ 568	\$ 2,140	\$ 2,240

10. *Implied DCF.* The following table reconciles the mid-point of adjusted EBITDA to implied DCF for the three-month period ending September 30, 2013 and the three-month and twelve-month periods ending December 31, 2013.

	Mid-Point Guidance		
	Three Months Ending September 30, 2013	Three Months Ending December 31, 2013	Twelve Months Ending December 31, 2013
	(in millions)		
Adjusted EBITDA	\$ 430	\$ 543	\$ 2,190
Interest expense, net	(82)	(83)	(317)
Current income tax expense	(2)	(14)	(69)
Distributions to noncontrolling interests	(13)	(13)	(51)
Maintenance capital expenditures	(52)	(51)	(185)
Other, net	(1)	(2)	(4)
Implied DCF	\$ 280	\$ 380	\$ 1,564

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, 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 to be reasonable assumptions. Certain factors could cause actual results to differ materially from results 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 develop 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;

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- the currency exchange rate of the Canadian dollar;
- weather interference with business operations or project construction;
- risks related to the development and operation of our 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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC, its general partner

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

By: PLAINS ALL AMERICAN GP LLC, its general partner

Date: August 5, 2013

By: /s/ Charles Kingswell-Smith

Name: Charles Kingswell-Smith

Title: *Vice President and Treasurer*

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News Release

FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports Second-Quarter 2013 Results

(Houston — August 5, 2013) Plains All American Pipeline, L.P. (NYSE: PAA) reported second-quarter 2013 results as summarized below:

Summary Financial Information ⁽¹⁾

(in millions, except per unit data)

	Three Months Ended June 30,			% Change	Six Months Ended June 30,			% Change
	2013	2012			2013	2012		
Net income attributable to Plains	\$ 292	\$ 378		-23%	\$ 821	\$ 609		35%
Diluted net income per limited partner unit	\$ 0.57	\$ 0.93		-39%	\$ 1.84	\$ 1.44		28%
EBITDA	\$ 484	\$ 557		-13%	\$ 1,232	\$ 940		31%
	Three Months Ended June 30,			% Change	Six Months Ended June 30,			% Change
	2013	2012			2013	2012		
Adjusted net income attributable to Plains	\$ 287	\$ 343		-16%	\$ 811	\$ 663		22%
Diluted adjusted net income per limited partner unit	\$ 0.56	\$ 0.82		-32%	\$ 1.82	\$ 1.61		13%
Adjusted EBITDA	\$ 478	\$ 522		-8%	\$ 1,217	\$ 995		22%
Distribution declared for the period	\$ 0.5875	\$ 0.5325		10.3%				

⁽¹⁾ The Partnership's reported results include the impact of items that affect comparability between reporting periods. The impact of these items is excluded from adjusted results. See the section of this release entitled "Non-GAAP Financial Measures and Selected Items Impacting Comparability" and the tables attached hereto for information regarding selected items that the Partnership believes impact comparability of financial results between reporting periods, as well as for information regarding non-GAAP financial measures (such as adjusted EBITDA) and their reconciliation to the most directly comparable GAAP measures.

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"PAA delivered solid second-quarter results, exceeding the high-end of our guidance and in line with our updated outlook provided in late May," said Greg L. Armstrong, Chairman and CEO of Plains All American. "These results include an approximate \$25 million adverse impact associated with certain operational issues that occurred during the second quarter of 2013.

"This performance was driven by continued strong fundamentals and favorable market conditions, albeit less favorable than experienced during the first quarter of 2013 or the second quarter of 2012. We have increased the midpoint of our 2013 adjusted EBITDA guidance by \$30 million to \$2.19 billion, incorporating our strong performance to date and an assumed return to baseline performance levels in our Supply and Logistics segment in the second half of the year.

"We have performed well thus far this year and we are on track to achieve our 2013 goals. Our distribution payable next week represents a 10.3% increase over our distribution paid in August 2012, which is consistent with our 2013 target of 9 to 10% year-over-year distribution growth, and we expect distribution coverage for 2013 to exceed 130%. We have increased our expansion capital program by \$200 million to \$1.6 billion and continue to advance our multi-billion dollar project portfolio. Furthermore, PAA remains financially well-positioned, ending the quarter with a strong balance sheet, favorable credit metrics compared to our targets, and approximately \$2.6 billion in committed liquidity."

The following table summarizes selected financial information by segment for the second quarter and first half of 2013:

Summary of Selected Financial Data by Segment ⁽¹⁾

(in millions)

	Three Months Ended June 30, 2013			Three Months Ended June 30, 2012		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Reported segment profit	\$ 160	\$ 149	\$ 176	\$ 169	\$ 114	\$ 274
Selected items impacting the comparability of segment profit ⁽²⁾	7	4	(22)	11	5	(53)
Adjusted segment profit	\$ 167	\$ 153	\$ 154	\$ 180	\$ 119	\$ 221
Percentage change in adjusted segment profit versus 2012 period	-7%	29%	-30%			

	Six Months Ended June 30, 2013			Six Months Ended June 30, 2012		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Reported segment profit	\$ 323	\$ 300	\$ 610	\$ 332	\$ 204	\$ 402
Selected items impacting the comparability of segment profit ⁽²⁾	18	10	(49)	21	15	17
Adjusted segment profit	\$ 341	\$ 310	\$ 561	\$ 353	\$ 219	\$ 419
Percentage change in adjusted segment profit versus 2012 period	-3%	42%	34%			

⁽¹⁾ The Partnership's reported results include the impact of items that affect comparability between reporting periods. The impact of these items is excluded from adjusted results. See the section of this release entitled "Non-GAAP Financial Measures and Selected Items Impacting Comparability" and the tables attached hereto for information regarding selected items that the Partnership believes impact comparability of financial results between reporting periods.

⁽²⁾ Certain of our non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

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Second-quarter 2013 Transportation adjusted segment profit decreased 7% versus comparable 2012 results. This decrease was driven by lost revenue and incremental expenses related to operational issues that occurred during the second quarter of 2013. This impact was partially offset by the benefit of increased volumes from increased producer drilling activities and recently completed organic growth projects.

Second-quarter 2013 Facilities adjusted segment profit increased 29% over comparable 2012 results. This increase was primarily related to the benefit of a recently completed crude oil rail acquisition and rail-related organic growth projects as well as increased profitability from NGL fractionation and gas processing activities.

Second-quarter 2013 Supply and Logistics adjusted segment profit exceeded our guidance, but represented a 30% decrease relative to comparable 2012 results. This decrease was primarily related to relatively less favorable crude oil market conditions, particularly narrower crude oil differentials, partially offset by higher net margins in the NGL business.

The Partnership will hold a conference call on August 6, 2013 (see details below). Prior to this conference call, the Partnership will furnish a current report on Form 8-K, which will include material in this news release as well as financial and operational guidance for the third 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, where PAA routinely posts important information about the Partnership.

Conference Call

The Partnership's conference call will be held at 11:00 a.m. EDT on Tuesday, August 6, 2013 to discuss the following items:

1. The Partnership's second-quarter 2013 performance;
2. The status of major expansion projects;
3. Capitalization and liquidity;
4. Financial and operating guidance for the third quarter and full year of 2013; and
5. The Partnership's outlook for the future.

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Conference Call Access Instructions

To access the Internet webcast of the conference call, 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, access to the live conference call is available by dialing toll free (888) 276-0010. International callers should dial (612) 332-1210. No password is required. The slide presentation accompanying the conference call will be 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 the PAA website at www.paalp.com.

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial (800) 475-6701 or (320) 365-3844 for international callers and enter replay access code 295443. The replay will be available beginning Tuesday, August 6, 2013, at approximately 1:00 p.m. EDT and will continue until 12:59 a.m. EDT on September 7, 2013.

Non-GAAP Financial Measures and Selected Items Impacting Comparability

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as "non-GAAP financial measures" (such as adjusted EBITDA and implied distributable cash flow) 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 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), (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." We consider an understanding of these selected items impacting comparability to be material to the evaluation of our operating results and prospects.

Although we present selected items that we consider in evaluating our performance, you should also be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions and numerous other factors. These types of variations are not separately identified in this release, but will be discussed, as applicable, in management's discussion and analysis of operating results in our Quarterly Report on Form 10-Q.

Adjusted EBITDA and other non-GAAP financial measures are reconciled to the most comparable GAAP measures for the periods presented in the tables attached to this release, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and notes thereto. In addition, the Partnership maintains on its website (www.paalp.com) a reconciliation of adjusted EBITDA and certain commonly used non-GAAP financial information 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.

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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, 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 volumes 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 develop 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 our 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 also owns and operates natural gas storage facilities. PAA is headquartered in Houston, Texas.

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

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
REVENUES	\$ 10,295	\$ 9,786	\$ 20,915	\$ 19,004
COSTS AND EXPENSES				
Purchases and related costs	9,387	8,830	18,825	17,332
Field operating costs	343	319	684	568
General and administrative expenses	91	89	196	182
Depreciation and amortization	91	86	173	146
Total costs and expenses	9,912	9,324	19,878	18,228
OPERATING INCOME	383	462	1,037	776
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	11	9	23	16
Interest expense, net	(75)	(75)	(152)	(140)
Other income/(expense), net	(1)	—	(1)	2
INCOME BEFORE TAX	318	396	907	654
Current income tax expense	(8)	(6)	(53)	(23)
Deferred income tax expense	(10)	(4)	(17)	(7)
NET INCOME	300	386	837	624
Net income attributable to noncontrolling interests	(8)	(8)	(16)	(15)
NET INCOME ATTRIBUTABLE TO PLAINS	\$ 292	\$ 378	\$ 821	\$ 609
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	\$ 197	\$ 303	\$ 631	\$ 465
GENERAL PARTNER	\$ 95	\$ 75	\$ 190	\$ 144
BASIC NET INCOME PER LIMITED PARTNER UNIT	\$ 0.58	\$ 0.93	\$ 1.85	\$ 1.45
DILUTED NET INCOME PER LIMITED PARTNER UNIT	\$ 0.57	\$ 0.93	\$ 1.84	\$ 1.44
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	340	323	338	319
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	342	326	341	321

ADJUSTED RESULTS:

(in millions, except per unit data)

Three Months Ended

Six Months Ended

	June 30,		June 30,	
	2013	2012	2013	2012
ADJUSTED NET INCOME ATTRIBUTABLE TO PLAINS	\$ 287	\$ 343	\$ 811	\$ 663
DILUTED ADJUSTED NET INCOME PER LIMITED PARTNER UNIT	\$ 0.56	\$ 0.82	\$ 1.82	\$ 1.61
ADJUSTED EBITDA	\$ 478	\$ 522	\$ 1,217	\$ 995

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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CONDENSED CONSOLIDATED BALANCE SHEET DATA

(in millions)

	June 30, 2013	December 31, 2012
ASSETS		
Current assets	\$ 4,841	\$ 5,147
Property and equipment, net	10,181	9,643
Goodwill	2,503	2,535
Linefill and base gas	707	707
Long-term inventory	207	274
Investments in unconsolidated entities	442	343
Other, net	543	586
Total assets	\$ 19,424	\$ 19,235
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	\$ 4,924	\$ 5,183
Senior notes, net of unamortized discount	6,011	6,010
Long-term debt under credit facilities and other	302	310
Other long-term liabilities and deferred credits	558	586
Total liabilities	11,795	12,089
Partners' capital excluding noncontrolling interests	7,098	6,637
Noncontrolling interests	531	509
Total partners' capital	7,629	7,146
Total liabilities and partners' capital	\$ 19,424	\$ 19,235

DEBT CAPITALIZATION RATIOS

(in millions)

	June 30, 2013	December 31, 2012
Short-term debt	\$ 902	\$ 1,086
Long-term debt	6,313	6,320
Total debt	\$ 7,215	\$ 7,406
Long-term debt	\$ 6,313	\$ 6,320
Partners' capital	7,629	7,146
Total book capitalization	\$ 13,942	\$ 13,466
Total book capitalization, including short-term debt	\$ 14,844	\$ 14,552
Long-term debt-to-total book capitalization	45%	47%
Total debt-to-total book capitalization, including short-term debt	49%	51%

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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SELECTED FINANCIAL DATA BY SEGMENT

(in millions)

	Three Months Ended June 30, 2013			Three Months Ended June 30, 2012		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues ⁽¹⁾	\$ 365	\$ 348	\$ 9,934	\$ 361	\$ 287	\$ 9,442
Purchases and related costs ⁽¹⁾	(39)	(83)	(9,614)	(35)	(65)	(9,030)
Field operating costs (excluding equity-indexed compensation expense) ⁽¹⁾	(138)	(94)	(109)	(128)	(86)	(105)
Equity-indexed compensation expense - operations	(4)	—	(1)	(3)	—	(1)
Segment G&A expenses (excluding equity- indexed compensation expense) ⁽²⁾	(26)	(16)	(27)	(28)	(18)	(27)
Equity-indexed compensation expense - general and administrative	(9)	(6)	(7)	(7)	(4)	(5)
Equity earnings in unconsolidated entities	11	—	—	9	—	—
Reported segment profit	\$ 160	\$ 149	\$ 176	\$ 169	\$ 114	\$ 274
Selected items impacting comparability of segment profit ⁽³⁾	7	4	(22)	11	5	(53)
Segment profit excluding selected items impacting comparability	\$ 167	\$ 153	\$ 154	\$ 180	\$ 119	\$ 221
Maintenance capital	\$ 23	\$ 11	\$ 5	\$ 27	\$ 10	\$ 3
	Six Months Ended June 30, 2013			Six Months Ended June 30, 2012		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues ⁽¹⁾	\$ 732	\$ 703	\$ 20,158	\$ 678	\$ 523	\$ 18,319
Purchases and related costs ⁽¹⁾	(74)	(174)	(19,249)	(63)	(139)	(17,638)
Field operating costs (excluding equity-indexed compensation expense) ⁽¹⁾	(270)	(180)	(224)	(224)	(133)	(207)
Equity-indexed compensation expense - operations	(13)	(1)	(2)	(10)	(1)	(1)
Segment G&A expenses (excluding equity- indexed compensation expense) ⁽²⁾	(49)	(32)	(53)	(49)	(32)	(53)
Equity-indexed compensation expense - general and administrative	(26)	(16)	(20)	(16)	(14)	(18)
Equity earnings in unconsolidated entities	23	—	—	16	—	—
Reported segment profit	\$ 323	\$ 300	\$ 610	\$ 332	\$ 204	\$ 402
Selected items impacting comparability of segment profit ⁽³⁾	18	10	(49)	21	15	17
Segment profit excluding selected items impacting comparability	\$ 341	\$ 310	\$ 561	\$ 353	\$ 219	\$ 419
Maintenance capital	\$ 55	\$ 18	\$ 9	\$ 52	\$ 17	\$ 7

⁽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. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period. Includes acquisition-related expenses for the 2012 period.⁽³⁾ Certain non-GAAP financial measures may not be impacted by each of the selected items impacting comparability.

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**PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)****OPERATING DATA ⁽¹⁾**

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012

**Transportation activities (average daily volumes in thousands of
barrels):**

Tariff activities

Crude Oil Pipelines

All American	38	31	39	28
Bakken Area Systems	130	135	127	136
Basin / Mesa	680	707	702	675
Capline	158	149	157	136
Eagle Ford Area Systems	74	15	61	12
Line 63 / Line 2000	108	130	113	124
Manito	46	57	46	62
Mid-Continent Area Systems	255	262	261	242
Permian Basin Area Systems	548	447	513	451
Rainbow	125	156	124	149
Rangeland	56	61	62	62
Salt Lake City Area Systems	131	157	133	148
South Saskatchewan	33	59	46	60
White Cliffs	21	17	21	17
Other	766	743	763	735
NGL Pipelines				
Co-Ed	51	64	54	32
Other	165	159	186	79
Refined Products Pipelines	110	118	105	115
Tariff activities total	3,495	3,467	3,513	3,263
Trucking	108	96	109	102
Transportation activities total	3,603	3,563	3,622	3,365

Facilities activities (average monthly volumes):

Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	95	93	94	85
Rail load / unload volumes (average throughput in thousands of barrels per day)	231	—	223	—
Natural gas storage (average monthly capacity in billions of cubic feet)	97	80	95	78
NGL fractionation (average throughput in thousands of barrels per day)	90	108	95	60
Facilities activities total (average monthly capacity in millions of barrels) ⁽²⁾	121	109	120	100

Supply and Logistics activities (average daily volumes in thousands of barrels):

Crude oil lease gathering purchases	853	814	855	806
NGL sales	160	153	221	144
Waterborne cargos	7	4	6	2
Supply and Logistics activities total	1,020	971	1,082	952

⁽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⁾ Facilities total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes 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 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)

COMPUTATION OF BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Basic Net Income per Limited Partner Unit:				
Net income attributable to Plains	\$ 292	\$ 378	\$ 821	\$ 609
Less: General partner's incentive distribution ⁽¹⁾	(91)	(69)	(177)	(134)
Less: General partner 2% ownership ⁽¹⁾	(4)	(6)	(13)	(10)
Net income available to limited partners	197	303	631	465
Less: Undistributed earnings allocated and distributions to participating securities ⁽¹⁾	(1)	(2)	(5)	(3)
Net income available to limited partners in accordance with application of the two-class method for MLPs	\$ 196	\$ 301	\$ 626	\$ 462

Basic weighted average number of limited partner units outstanding	340	323	338	319
Basic net income per limited partner unit	\$ 0.58	\$ 0.93	\$ 1.85	\$ 1.45
Diluted Net Income per Limited Partner Unit:				
Net income attributable to Plains	\$ 292	\$ 378	\$ 821	\$ 609
Less: General partner's incentive distribution ⁽¹⁾	(91)	(69)	(177)	(134)
Less: General partner 2% ownership ⁽¹⁾	(4)	(6)	(13)	(10)
Net income available to limited partners	197	303	631	465
Less: Undistributed earnings allocated and distributions to participating securities ⁽¹⁾	(1)	(1)	(3)	(2)
Net income available to limited partners in accordance with application of the two-class method for MLPs	\$ 196	\$ 302	\$ 628	\$ 463
Basic weighted average number of limited partner units outstanding	340	323	338	319
Effect of dilutive securities: Weighted average LTIP units ⁽²⁾	2	3	3	2
Diluted weighted average number of limited partner units outstanding	342	326	341	321
Diluted net income per limited partner unit	\$ 0.57	\$ 0.93	\$ 1.84	\$ 1.44

⁽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 Long-term Incentive Plan ("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.

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FINANCIAL SUMMARY (unaudited)

SELECTED ITEMS IMPACTING COMPARABILITY

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Selected Items Impacting Comparability - Income/(Loss) ⁽¹⁾:				
Gains/(losses) from derivative activities net of inventory valuation adjustments ⁽²⁾	\$ 26	\$ 72	\$ 50	\$ 13
Equity-indexed compensation expense ⁽³⁾	(16)	(12)	(39)	(38)
Net gain/(loss) on foreign currency revaluation	(4)	(16)	4	(16)
Tax effect on selected items impacting comparability	(1)	—	(6)	—
Significant acquisition-related expenses	—	(9)	—	(13)
Other ⁽⁴⁾	—	—	1	—
Selected items impacting comparability of net income attributable to Plains	\$ 5	\$ 35	\$ 10	\$ (54)
Impact to basic net income per limited partner unit	\$ 0.02	\$ 0.11	\$ 0.02	\$ (0.16)
Impact to diluted net income per limited partner unit	\$ 0.01	\$ 0.11	\$ 0.02	\$ (0.17)

⁽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⁾ Equity-indexed compensation expense above excludes the portion of equity-indexed compensation expense represented by grants under LTIP that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units.

⁽⁴⁾ Includes other immaterial selected items impacting comparability, as well as the noncontrolling interests' portion of selected items.

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FINANCIAL SUMMARY (unaudited)

COMPUTATION OF ADJUSTED BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT

(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Basic Adjusted Net Income per Limited Partner Unit				
Net income attributable to Plains	\$ 292	\$ 378	\$ 821	\$ 609
Selected items impacting comparability of net income attributable to Plains ⁽¹⁾	(5)	(35)	(10)	54
Adjusted net income attributable to Plains	287	343	811	663
Less: General partner's incentive distribution ⁽²⁾	(91)	(69)	(177)	(134)
Less: General partner 2% ownership ⁽²⁾	(4)	(5)	(13)	(11)
Adjusted net income available to limited partners	192	269	621	518
Less: Undistributed earnings allocated and distributions to participating securities ⁽²⁾	(1)	(2)	(4)	(3)
Adjusted limited partners' net income	<u>\$ 191</u>	<u>\$ 267</u>	<u>\$ 617</u>	<u>\$ 515</u>
Basic weighted average number of limited partner units outstanding	340	323	338	319
Basic adjusted net income per limited partner unit	<u>\$ 0.56</u>	<u>\$ 0.82</u>	<u>\$ 1.83</u>	<u>\$ 1.61</u>
Diluted Adjusted Net Income per Limited Partner Unit				
Net income attributable to Plains	\$ 292	\$ 378	\$ 821	\$ 609
Selected items impacting comparability of net income attributable to Plains ⁽¹⁾	(5)	(35)	(10)	54
Adjusted net income attributable to Plains	287	343	811	663
Less: General partner's incentive distribution ⁽²⁾	(91)	(69)	(177)	(134)
Less: General partner 2% ownership ⁽²⁾	(4)	(5)	(13)	(11)
Adjusted net income available to limited partners	192	269	621	518
Less: Undistributed earnings allocated and distributions to participating securities ⁽²⁾	(1)	(1)	(3)	(2)
Adjusted limited partners' net income	<u>\$ 191</u>	<u>\$ 268</u>	<u>\$ 618</u>	<u>\$ 516</u>
Diluted weighted average number of limited partner units outstanding	342	326	341	321
Diluted adjusted net income per limited partner unit	<u>\$ 0.56</u>	<u>\$ 0.82</u>	<u>\$ 1.82</u>	<u>\$ 1.61</u>

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

⁽²⁾ 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.

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

FINANCIAL DATA RECONCILIATIONS

(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net Income to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") and Excluding Selected Items Impacting Comparability ("Adjusted EBITDA") Reconciliations				
Net Income	\$ 300	\$ 386	\$ 837	\$ 624
Add: Interest expense	75	75	152	140
Add: Income tax expense	18	10	70	30
Add: Depreciation and amortization	91	86	173	146
EBITDA	<u>\$ 484</u>	<u>\$ 557</u>	<u>\$ 1,232</u>	<u>\$ 940</u>
Selected items impacting comparability of EBITDA ⁽¹⁾	(6)	(35)	(15)	55
Adjusted EBITDA	<u>\$ 478</u>	<u>\$ 522</u>	<u>\$ 1,217</u>	<u>\$ 995</u>

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Adjusted EBITDA to Implied Distributable Cash Flow (“DCF”)				
Adjusted EBITDA	\$ 478	\$ 522	\$ 1,217	\$ 995
Interest expense	(75)	(75)	(152)	(140)
Maintenance capital	(39)	(40)	(82)	(76)
Current income tax expense	(8)	(6)	(53)	(23)
Equity earnings in unconsolidated entities, net of distributions	(1)	1	(1)	—
Distributions to noncontrolling interests ⁽¹⁾	(13)	(12)	(25)	(24)
Implied DCF	<u>\$ 342</u>	<u>\$ 390</u>	<u>\$ 904</u>	<u>\$ 732</u>

(1) Includes distributions that pertain to the current period’s net income, which are paid in the subsequent period.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Cash Flow from Operating Activities Reconciliation				
EBITDA	\$ 484	\$ 557	\$ 1,232	\$ 940
Current income tax expense	(8)	(6)	(53)	(23)
Interest expense	(75)	(75)	(152)	(140)
Net change in assets and liabilities, net of acquisitions	(70)	(466)	232	(489)
Other items to reconcile to cash flows from operating activities:				
Equity-indexed compensation expense	27	20	78	60
Net cash provided by operating activities	<u>\$ 358</u>	<u>\$ 30</u>	<u>\$ 1,337</u>	<u>\$ 348</u>

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