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 6, 2014**

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 August 6, 2014

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 2014 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 2014. 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 2014 Guidance; Update of Full Year 2014 Guidance

We based our guidance for the three-month period ending September 30, 2014 and three-month and twelve-month periods ending December 31, 2014 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 5, 2014. 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 2014 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.plainsallamerican.com* (in particular the section under Investor Relations entitled "Guidance and Non-GAAP Reconciliations"), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. 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." 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.

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

	Actual	Guidance [a]					
	6 Months Ended	3 Months Ending Sep 30, 2014		3 Months Ending Dec 31, 2014		12 Months Ending Dec 31, 2014	
	Jun 30, 2014	Low	High	Low	High	Low	High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 1,972	$ 903	$ 938	$ 1,013	$ 1,048	$ 3,888	$ 3,958
Field operating costs	(696)	(377)	(367)	(352)	(342)	(1,425)	(1,405)
General and administrative expenses	(179)	(85)	(80)	(83)	(78)	(347)	(337)
	1,097	441	491	578	628	2,116	2,216
Depreciation and amortization expense	(196)	(94)	(90)	(95)	(91)	(385)	(377)
Interest expense, net	(161)	(88)	(84)	(90)	(86)	(339)	(331)
Income tax expense	(70)	(8)	(4)	(38)	(34)	(116)	(108)
Other income / (expense), net	2	—	—	—	—	2	2
Net Income	**672**	**251**	**313**	**355**	**417**	**1,278**	**1,402**
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(1)	(1)	(3)	(3)
Net Income Attributable to PAA	**$ 671**	**$ 250**	**$ 312**	**$ 354**	**$ 416**	**$ 1,275**	**$ 1,399**
Net Income to Limited Partners [b]	$ 435	$ 123	$ 184	$ 216	$ 279	$ 777	$ 898
Basic Net Income Per Limited Partner Unit [b]							
Weighted Average Units Outstanding	363	369	369	372	372	367	367
Net Income Per Unit	$ 1.19	$ 0.33	$ 0.49	$ 0.58	$ 0.75	$ 2.10	$ 2.43
Diluted Net Income Per Limited Partner Unit [b]							
Weighted Average Units Outstanding	365	372	372	374	374	369	369
Net Income Per Unit	$ 1.18	$ 0.33	$ 0.49	$ 0.58	$ 0.74	$ 2.09	$ 2.42
EBIT	**$ 903**	**$ 347**	**$ 401**	**$ 483**	**$ 537**	**$ 1,733**	**$ 1,841**
EBITDA	**$ 1,099**	**$ 441**	**$ 491**	**$ 578**	**$ 628**	**$ 2,118**	**$ 2,218**
Selected Items Impacting Comparability							
Equity-indexed compensation expense	$ (36)	$ (14)	$ (14)	$ (13)	$ (13)	$ (63)	$ (63)
Tax effect on selected items impacting comparability	(9)	—	—	—	—	(9)	(9)
Net gain / (loss) on foreign currency revaluation	6	—	—	—	—	6	6
Gains / (losses) from derivative activities, net of inventory valuation adjustments	50	—	—	—	—	50	50
Selected Items Impacting Comparability of Net Income attributable to PAA	$ 11	$ (14)	$ (14)	$ (13)	$ (13)	$ (16)	$ (16)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 443	$ 225	$ 235	$ 261	$ 271	$ 929	$ 949
Facilities	297	130	140	146	156	573	593
Supply and Logistics	338	100	130	184	214	622	682
Other income, net	1	—	—	—	—	1	1
Adjusted EBITDA	$ 1,079	$ 455	$ 505	$ 591	$ 641	$ 2,125	$ 2,225
Adjusted Net Income Attributable to PAA	$ 660	$ 264	$ 326	$ 367	$ 429	$ 1,291	$ 1,415
Basic Adjusted Net Income Per Limited Partner Unit [b]	$ 1.16	$ 0.36	$ 0.53	$ 0.62	$ 0.78	$ 2.14	$ 2.47
Diluted Adjusted Net Income Per Limited Partner Unit [b]	$ 1.15	$ 0.36	$ 0.53	$ 0.61	$ 0.78	$ 2.12	$ 2.46

(a) The assumed average foreign exchange rate is $1.10 Canadian to $1.00 U.S. for the six-month period ending December 31, 2014. The rate as of August 5, 2014 was $1.10 Canadian to $1.00 U.S. A $0.05 change in the FX rate will impact adjusted EBITDA for the six months ending December 31, 2014 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.

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
G&A	General and administrative
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. The Transportation segment generates 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 interests ranging from 22% to 50% and account for these under the equity method of accounting.

   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 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.

	Actual	Guidance		
	Six Months Ended Jun 30, 2014	Three Months Ending Sep 30, 2014	Three Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
Average Daily Volumes (MBbls/d)				
Crude Oil Pipelines				
All American	36	35	35	35
Bakken Area Systems	138	155	160	148
Basin/Mesa	729	735	740	733
Capline	123	155	155	139
Eagle Ford Area Systems	199	230	260	222
Line 63 / 2000	116	120	145	124
Manito	44	45	45	45
Mid-Continent Area Systems	338	380	395	363
Permian Basin Area Systems	759	780	830	782
Rainbow	114	120	120	117
Rangeland	67	60	65	65
Salt Lake City Area Systems	131	140	130	133
South Saskatchewan	61	55	55	58
White Cliffs	24	25	35	27
Other	703	790	785	746
NGL Pipelines				
Co-Ed	56	55	60	57
Other	119	120	110	117
	3,757	4,000	4,125	3,911
Trucking	129	135	145	135
	3,886	4,135	4,270	4,046
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.63	$ 0.60 (1)	$ 0.68 (1)	$ 0.64 (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 and natural gas and condensate processing services. The Facilities segment generates 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) fees from NGL fractionation and isomerization, (v) fees from gas and condensate processing services and (vi) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing 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.

	Actual	Guidance		
	Six Months Ended Jun 30, 2014	Three Months Ending Sep 30, 2014	Three Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
Operating Data				
Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)	95	95	95	95
Rail Load / Unload Volumes (MBbls/d)	227	250	275	245
Natural Gas Storage (Bcf/Mo.)	97	97	97	97
NGL Fractionation (MBbls/d)	89	95	95	92
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) [1]	121	122	123	121
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.41	$ 0.37[2]	$ 0.41[2]	$ 0.40[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 and natural gas;
- 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;
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities; and
- the purchase and sale of natural gas.

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 G&A 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 market volatility as well as variable operating expenses. Forecasted operating results for the three-month period ending September 30, 2014 reflect the current market structure and forecasted operating results for the three and six month periods ending December 31, 2014 reflect seasonal and weather-related variations in NGL and natural gas sales. Our guidance is also based on an expectation that domestic crude 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 temporary market-driven storage and withdrawal of crude 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.

	Actual	Guidance		
	Six Months Ended Jun 30, 2014	Three Months Ending Sep 30, 2014	Three Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
Average Daily Volumes (MBbls/d)				
Crude Oil Lease Gathering Purchases	912	965	995	946
NGL Sales	205	135	255	200
	1,117	1,100	1,250	1,146
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 1.67	$ 1.14[1]	$ 1.73[1]	$ 1.56[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, acceleration of depreciation 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 the calendar year of 2014 to be approximately $1.95 billion for expansion projects with an additional $185 to $205 million for maintenance capital projects. During the first six months of 2014, we spent $1,012 million and $95 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, 2014:

	Calendar 2014 (in millions)
Expansion Capital	
· Permian Basin Area Projects	$480
· Cactus Pipeline	350
· Rail Terminal Projects (1)	220
· Ft. Sask Facility Projects / NGL Line	135
· Western Oklahoma Extension	80
· Eagle Ford JV Project	65
· Mississippian Lime Pipeline	50
· White Cliffs Expansion	40
· Line 63 Reactivation	35
· Natural Gas Storage Expansions	35
· Other Projects	460
	$1,950
Potential Adjustments for Timing / Scope Refinement (2)	- $100 + $100
Total Projected Expansion Capital Expenditures	$1,850 - $2,050
Maintenance Capital Expenditures	$185 - $205

(1) Includes projects located in or near Bakersfield, CA, Carr, CO, Van Hook, ND and Kerrobert, Canada.
(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 June 30, 2014 and adjusted for estimated equity issuances under our continuous offering program.

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 2014.

   Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for hedged inventory. We treat interest on hedged inventory borrowings as carrying costs of crude oil, NGL, and natural gas and include it in purchases and related costs.

7. *Income Taxes*. We expect our Canadian income tax expense to be approximately $6 million and $112 million for the three-month period ending September 30, 2014 and twelve-month period ending December 31,2014, respectively, of which approximately $5 million and $88 million, respectively, is classified as a current income tax expense. For the twelve-month period ending December 31, 2014 we expect to have a deferred tax expense of $24 million. All or part of the annual income tax expense of $112 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 6, 2014, estimated vesting dates range from August 2014 to August 2019 and annualized benchmark distribution levels range from $2.05 to $3.10. 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, 2014, we declared an annualized distribution of $2.58 payable on August 14, 2014 to our unitholders of record as of August 1, 2014. For the purposes of guidance, we have made the assessment that an annualized $2.85 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $60 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) our then current probability assessment regarding distributions, and (iv) new equity-indexed compensation award grants, including the timing of such grant issuances. For example, a $2 change in the unit price would change 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 six-month period ended June 30, 2014, three-month period ending September 30, 2014, and the three-month and twelve-month periods

ending December 31, 2014.

	Actual 6 Months Ended Jun 30, 2014	Guidance 3 Months Ending Sep 30, 2014 Low	3 Months Ending Sep 30, 2014 High	3 Months Ending Dec 31, 2014 Low	3 Months Ending Dec 31, 2014 High	12 Months Ending Dec 31, 2014 Low	12 Months Ending Dec 31, 2014 High
				(in millions)			
Reconciliation to EBITDA and Adjusted EBITDA							
Net Income	$ 672	$ 251	$ 313	$ 355	$ 417	$ 1,278	$ 1,402
Interest expense, net	161	88	84	90	86	339	331
Income tax expense	70	8	4	38	34	116	108
EBIT	903	347	401	483	537	1,733	1,841
Depreciation and amortization	196	94	90	95	91	385	377
EBITDA	$ 1,099	$ 441	$ 491	$ 578	$ 628	$ 2,118	$ 2,218
Selected Items Impacting Comparability of EBITDA	(20)	14	14	13	13	7	7
Adjusted EBITDA	**$ 1,079**	**$ 455**	**$ 505**	**$ 591**	**$ 641**	**$ 2,125**	**$ 2,225**

10. *Implied DCF.* The following table reconciles adjusted EBITDA to implied DCF for the six-month period ended June 30, 2014, the three-month period ending September 30, 2014 and the three-month and twelve-month periods ending December 31, 2014.

	Actual Six Months Ended Jun 30, 2014	Mid-Point Guidance Three Months Ending Sep 30, 2014	Three Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
		(in millions)		
Adjusted EBITDA	$ 1,079	$ 480	$ 616	$ 2,175
Interest expense, net	(161)	(86)	(88)	(335)
Current income tax expense	(52)	(5)	(31)	(88)
Maintenance capital expenditures	(95)	(50)	(50)	(195)
Other, net	5	(3)	(1)	1
Implied DCF	$ 776	$ 336	$ 446	$ 1,558

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 the 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);
- 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;
- 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 occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- 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 currency exchange rate of the Canadian dollar;
- 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;

- shortages or cost increases of supplies, materials or labor;

- the effectiveness of our risk management activities;

- 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;

- 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;

- risks related to the development and operation of our facilities, including our ability to satisfy our contractual obligations to our customers at 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.

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 6, 2014	By: /s/ Charles Kingswell-Smith
	Name: Charles Kingswell-Smith
	Title: *Vice President and Treasurer*

PLAINS ALL AMERICAN PIPELINE, L.P. PLAINS GP HOLDINGS News Release

FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. and Plains GP Holdings Report Second-Quarter 2014 Results

(Houston — August 6, 2014) Plains All American Pipeline, L.P. (NYSE: PAA) and Plains GP Holdings (NYSE: PAGP) today reported second-quarter 2014 results, with PAA's results exceeding the midpoint of its quarterly guidance range by 13%. PAA's second-quarter 2014 results exceeded the midpoint of quarterly guidance in all three of PAA's segments.

Plains All American Pipeline, L.P.

Summary Financial Information [(1)]
(in millions, except per unit data)

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	% Change	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	% Change
Net income attributable to PAA	$ 287	$ 292	-2%	$ 671	$ 821	-18%
Diluted net income per limited partner unit	$ 0.45	$ 0.57	-21%	$ 1.18	$ 1.84	-36%
EBITDA	$ 492	$ 484	2%	$ 1,099	$ 1,232	-11%

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	% Change	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	% Change
Adjusted net income attributable to PAA	$ 307	$ 287	7%	$ 660	$ 811	-19%
Diluted adjusted net income per limited partner unit	$ 0.50	$ 0.56	-11%	$ 1.15	$ 1.82	-37%
Adjusted EBITDA	$ 512	$ 478	7%	$ 1,079	$ 1,217	-11%
Distribution per unit declared for the period	$ 0.6450	$ 0.5875	9.8%			

(1) PAA's reported results include the impact of items that affect comparability between reporting periods. The impact of certain 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 certain selected items that PAA 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.

"PAA delivered solid second-quarter results, exceeding the high-end of our initial guidance range and slightly ahead of our updated outlook provided in June," stated Greg L. Armstrong, Chairman and CEO of Plains All American. "These results were driven by over performance in our Transportation and Supply and Logistics segments."

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Armstrong added, "PAA remains on track to achieve its distribution growth objective of 10% for 2014, while maintaining attractive distribution coverage. PAA's quarterly distribution of $0.6450 per unit, to be paid next week, represents a 9.8% increase over the quarterly distribution paid in August 2013. Given PAA's trajectory, PAGP also remains on track to achieve its distribution growth objective of 25% for 2014. PAGP's quarterly distribution of $0.1834 per share represents a 7.5% increase over the quarterly distribution paid in May of 2014 and a 23.1% increase over the initial quarterly distribution included in PAGP's October 2013 initial public offering ("IPO") prospectus.

As a result of PAA's first half performance and our outlook for near baseline performance for the remainder of the year, we have increased our full-year adjusted EBITDA guidance by $25 million to a mid-point of $2.175 billion," said Armstrong. "Our 2014 capital expansion program is proceeding well as we continue to advance a number of attractive projects included in our multi-billion dollar project portfolio. Furthermore, we are well positioned financially, ending the second quarter with a strong balance sheet, credit metrics favorable to PAA's targeted credit profile and approximately $2.2 billion of committed liquidity."

The following table summarizes selected PAA financial information by segment for the second quarter and first half of 2014:

Summary of Selected Financial Data by Segment [(1)]
(in millions)

	Three Months Ended June 30, 2014 Transportation	Three Months Ended June 30, 2014 Facilities	Three Months Ended June 30, 2014 Supply and Logistics	Three Months Ended June 30, 2013 Transportation	Three Months Ended June 30, 2013 Facilities	Three Months Ended June 30, 2013 Supply and Logistics
Reported segment profit	$ 221	$ 134	$ 133	$ 160	$ 149	$ 176
Selected items impacting the	8	4	11	7	4	(22)

comparability of segment profit (2)						
Adjusted segment profit	***$ 229***	***$ 138***	***$ 144***	***$ 167***	***$ 153***	***$ 154***
Percentage change in adjusted segment profit versus 2013 period	***37%***	***-10%***	***-6%***			

	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013		
	Transportation	**Facilities**	**Supply and Logistics**	**Transportation**	**Facilities**	**Supply and Logistics**
Reported segment profit	$ 427	$ 288	$ 382	$ 323	$ 300	$ 610
Selected items impacting the comparability of segment profit (2)	16	9	(44)	18	10	(49)
Adjusted segment profit	***$ 443***	***$ 297***	***$ 338***	***$ 341***	***$ 310***	***$ 561***
Percentage change in adjusted segment profit versus 2013 period	***30%***	***-4%***	***-40%***			

(1) PAA's reported results include the impact of items that affect comparability between reporting periods. The impact of certain 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 certain selected items that PAA 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 2014 Transportation adjusted segment profit increased 37% versus comparable 2013 results. This increase was primarily driven by higher crude oil pipeline volumes associated with recently completed organic growth projects and increased producer drilling activities, partially offset by the sale of our refined products pipelines in 2013.

Second-quarter 2014 Facilities adjusted segment profit decreased 10% over comparable 2013 results. This decrease was primarily due to the impact of recontracting capacity originally contracted at higher rates within our natural gas storage operations, as well as increased field operating costs. This impact was partially offset by increased profitability from our NGL storage and fractionation activities.

Second-quarter 2014 Supply and Logistics adjusted segment profit decreased by approximately 6% relative to comparable 2013 results. This decrease was primarily related to less favorable NGL market conditions and higher costs, primarily related to increased facility fees, in the second quarter of 2014 compared to the same 2013 period. These impacts were partially offset by more favorable crude oil market conditions during the second quarter of 2014.

Plains GP Holdings

PAGP's sole assets are its ownership interest in PAA's general partner and incentive distribution rights. As the control entity of PAA, PAGP consolidates PAA's results into its financial statements, which is reflected in the condensed consolidating balance sheet and income statement included at the end of this release. Information regarding PAGP's distributions is reflected below:

Summary Financial Information

	Q2 2014	Q1 2014	Distribution provided in IPO prospectus
Distribution per share for the period	$ 0.18340	$ 0.17055	$ 0.14904
Q2 2014 distribution percentage growth over previous benchmarks		7.5%	23.1%

Conference Call

PAA and PAGP will hold a conference call on August 7, 2014 (see details below). Prior to this conference call, PAA will furnish a current report on Form 8-K, which will include material in this news release as well as PAA's financial and operational guidance for the third quarter and full year of 2014. A copy of the Form 8-K will be available at www.plainsallamerican.com, where PAA and PAGP routinely post important information.

The PAA and PAGP conference call will be held at 11:00 a.m. EDT on Thursday, August 7, 2014 to discuss the following items:

1. PAA's second-quarter 2014 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 2014; and

5. PAA's and PAGP's outlook for the future.

Conference Call Access Instructions

To access the Internet webcast of the conference call, please go to www.plainsallamerican.com, choose "Investor Relations," and then choose "Events and Presentations." Following the live webcast, the call will be archived for a period of sixty (60) days on the website.

Alternatively, access to the live conference call is available by dialing toll free (800) 230-1085. International callers should dial (612) 332-0107. No password is required. The slide presentation accompanying the conference call will be available a few minutes prior to the call under the "Events and Presentations" tab of the PAA and PAGP Investor Relations sections of the above referenced website.

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 331340. The replay will be available beginning Thursday, August 7, 2014, at approximately 1:00 p.m. EDT and will continue until 11:59 p.m. EDT on September 7, 2014.

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, PAA maintains on its website (www.plainsallamerican.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 "Plains All American Pipeline, L.P." under the "Investor Relations" link on the home page, select the "Guidance & Non-GAAP Reconciliations" link and navigate to the "Non-GAAP Reconciliations" tab.

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); 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; 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 occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems; weather interference with business operations or project construction, including the impact of extreme weather events or conditions; 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 currency exchange rate of the Canadian dollar; 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; shortages or cost increases of supplies, materials or labor; the effectiveness of our risk management activities; 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; 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; risks related to the development and operation of our facilities, including our ability to satisfy our contractual obligations to our customers at 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 Partnerships' filings with the Securities and Exchange Commission.

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Plains All American Pipeline, L.P. is a publicly traded master limited partnership that owns and operates midstream energy infrastructure and provides logistics services for crude oil, natural gas liquids ("NGL"), natural gas and refined products. PAA owns an extensive network of pipeline transportation, terminalling, storage and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. On average, PAA handles over 3.5 million barrels per day of crude oil and NGL on its pipelines. PAA is headquartered in Houston, Texas.

Plains GP Holdings is a publicly traded entity that owns an interest in the general partner and incentive distribution rights of Plains All American Pipeline, L.P., one of the largest energy infrastructure and logistics companies in North America. PAGP 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, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
REVENUES	$ 11,195	$ 10,295	$ 22,878	$ 20,915
COSTS AND EXPENSES				
Purchases and related costs	10,280	9,387	20,950	18,825
Field operating costs	360	343	696	684
General and administrative expenses	90	91	179	196
Depreciation and amortization	100	91	196	173
Total costs and expenses	10,830	9,912	22,021	19,878
OPERATING INCOME	365	383	857	1,037
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	23	11	44	23
Interest expense, net	(82)	(75)	(161)	(152)
Other income/(expense), net	4	(1)	2	(1)
INCOME BEFORE TAX	310	318	742	907
Current income tax expense	(16)	(8)	(52)	(53)
Deferred income tax expense	(6)	(10)	(18)	(17)
NET INCOME	288	300	672	837
Net income attributable to noncontrolling interests	(1)	(8)	(1)	(16)
NET INCOME ATTRIBUTABLE TO PAA	$ 287	$ 292	$ 671	$ 821
NET INCOME ATTRIBUTABLE TO PAA:				
LIMITED PARTNERS	$ 166	$ 197	$ 435	$ 631
GENERAL PARTNER	$ 121	$ 95	$ 236	$ 190

BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.45	$ 0.58	$ 1.19	$ 1.85
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.45	$ 0.57	$ 1.18	$ 1.84
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	365	340	363	338
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	367	342	365	341

ADJUSTED RESULTS
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
ADJUSTED NET INCOME ATTRIBUTABLE TO PAA	$ 307	$ 287	$ 660	$ 811
DILUTED ADJUSTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.50	$ 0.56	$ 1.15	$ 1.82
ADJUSTED EBITDA	$ 512	$ 478	$ 1,079	$ 1,217

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

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(in millions)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets	$ 5,168	$ 4,964
Property and equipment, net	11,613	10,819
Goodwill	2,502	2,503
Linefill and base gas	895	798
Long-term inventory	287	251
Investments in unconsolidated entities	545	485
Other, net	485	540
Total assets	$ 21,495	$ 20,360
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities	$ 5,423	$ 5,411
Senior notes, net of unamortized discount	7,409	6,710
Long-term debt under credit facilities and other	5	5
Other long-term liabilities and deferred credits	546	531
Total liabilities	13,383	12,657
Partners' capital excluding noncontrolling interests	8,053	7,644
Noncontrolling interests	59	59
Total partners' capital	8,112	7,703
Total liabilities and partners' capital	$ 21,495	$ 20,360

DEBT CAPITALIZATION RATIOS
(in millions)

	June 30, 2014	December 31, 2013
Short-term debt	$ 763	$ 1,113
Long-term debt	7,414	6,715
Total debt	$ 8,177	$ 7,828
Long-term debt	$ 7,414	$ 6,715
Partners' capital	8,112	7,703
Total book capitalization	$ 15,526	$ 14,418
Total book capitalization, including short-term debt	$ 16,289	$ 15,531
Long-term debt-to-total book capitalization	48%	47%

Total debt-to-total book capitalization, including short-term debt	50%	50%

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

SELECTED FINANCIAL DATA BY SEGMENT
(in millions)

	Three Months Ended June 30, 2014			Three Months Ended June 30, 2013		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 412	$ 277	$ 10,860	$ 365	$ 348	$ 9,934
Purchases and related costs [1]	(41)	(12)	(10,578)	(39)	(83)	(9,614)
Field operating costs (excluding equity-indexed compensation expense) [1]	(137)	(106)	(112)	(138)	(94)	(109)
Equity-indexed compensation expense - operations	(5)	(2)	(1)	(4)	—	(1)
Segment G&A expenses (excluding equity-indexed compensation expense) [2]	(21)	(16)	(27)	(26)	(16)	(27)
Equity-indexed compensation expense - general and administrative	(10)	(7)	(9)	(9)	(6)	(7)
Equity earnings in unconsolidated entities	23	—	—	11	—	—
Reported segment profit	$ 221	$ 134	$ 133	$ 160	$ 149	$ 176
Selected items impacting comparability of segment profit [3]	8	4	11	7	4	(22)
Adjusted segment profit	$ 229	$ 138	$ 144	$ 167	$ 153	$ 154
Maintenance capital	$ 42	$ 5	$ 1	$ 23	$ 11	$ 5

	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013		
	Transportation	Facilities	Supply and Logistics	Transportation	Facilities	Supply and Logistics
Revenues [1]	$ 798	$ 576	$ 22,228	$ 732	$ 703	$ 20,158
Purchases and related costs [1]	(78)	(38)	(21,553)	(74)	(174)	(19,249)
Field operating costs (excluding equity-indexed compensation expense) [1]	(265)	(204)	(218)	(270)	(180)	(224)
Equity-indexed compensation expense - operations	(10)	(2)	(2)	(13)	(1)	(2)
Segment G&A expenses (excluding equity-indexed compensation expense) [2]	(43)	(29)	(53)	(49)	(32)	(53)
Equity-indexed compensation expense - general and administrative	(19)	(15)	(20)	(26)	(16)	(20)
Equity earnings in unconsolidated entities	44	—	—	23	—	—
Reported segment profit	$ 427	$ 288	$ 382	$ 323	$ 300	$ 610
Selected items impacting comparability of segment profit [3]	16	9	(44)	18	10	(49)
Adjusted segment profit	$ 443	$ 297	$ 338	$ 341	$ 310	$ 561
Maintenance capital	$ 76	$ 15	$ 4	$ 55	$ 18	$ 9

(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.
(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, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Transportation activities (average daily volumes in thousands of barrels per day):				
Tariff activities				
Crude Oil Pipelines				
All American	38	38	36	39
Bakken Area Systems	145	130	138	127
Basin / Mesa	714	680	729	702
Capline	121	158	123	157
Eagle Ford Area Systems	209	74	199	61
Line 63 / Line 2000	106	108	116	113
Manito	44	46	44	46
Mid-Continent Area Systems	360	282	338	287
Permian Basin Area Systems	759	548	759	513
Rainbow	108	125	114	124
Rangeland	65	56	67	62
Salt Lake City Area Systems	130	131	131	133
South Saskatchewan	58	33	61	46
White Cliffs	24	21	24	21
Other	745	739	703	737
NGL Pipelines				
Co-Ed	55	51	56	54
Other	123	165	119	186
Refined Products Pipelines	—	110	—	105
Tariff activities total	3,804	3,495	3,757	3,513
Trucking	127	108	129	109
Transportation activities total	3,931	3,603	3,886	3,622
Facilities activities (average monthly volumes):				
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	95	95	94
Rail load / unload volumes (average volumes in thousands of barrels per day)	224	231	227	223
Natural gas storage (average monthly capacity in billions of cubic feet)	97	97	97	95
NGL fractionation (average volumes in thousands of barrels per day)	86	90	89	95
Facilities activities total (average monthly volumes in millions of barrels) [(2)]	120	121	121	120
Supply and Logistics activities (average daily volumes in thousands of barrels per day):				
Crude oil lease gathering purchases	931	853	912	855
NGL sales	139	160	205	221
Waterborne cargos	—	7	—	6
Supply and Logistics activities total	1,070	1,020	1,117	1,082

(1) Volumes associated with assets employed through acquisitions and internal growth projects represent total volumes (attributable to our interest) for the number of days or months we employed 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, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
Basic Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 287	$ 292	$ 671	$ 821

Less: General partner's incentive distribution [1]	(117)	(91)	(227)	(177)
Less: General partner 2% ownership [1]	(4)	(4)	(9)	(13)
Net income available to limited partners	166	197	435	631
Less: Undistributed earnings allocated and distributions to participating securities [1]	(1)	(1)	(3)	(5)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 165	$ 196	$ 432	$ 626
Basic weighted average number of limited partner units outstanding	365	340	363	338
Basic net income per limited partner unit	$ 0.45	$ 0.58	$ 1.19	$ 1.85
Diluted Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 287	$ 292	$ 671	$ 821
Less: General partner's incentive distribution [1]	(117)	(91)	(227)	(177)
Less: General partner 2% ownership [1]	(4)	(4)	(9)	(13)
Net income available to limited partners	166	197	435	631
Less: Undistributed earnings allocated and distributions to participating securities [1]	(1)	(1)	(3)	(3)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 165	$ 196	$ 432	$ 628
Basic weighted average number of limited partner units outstanding	365	340	363	338
Effect of dilutive securities: Weighted average LTIP units [2]	2	2	2	3
Diluted weighted average number of limited partner units outstanding	367	342	365	341
Diluted net income per limited partner unit	$ 0.45	$ 0.57	$ 1.18	$ 1.84

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

SELECTED ITEMS IMPACTING COMPARABILITY
(in millions, except per unit data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Selected Items Impacting Comparability - Income/(Loss) [1]:				
Gains/(losses) from derivative activities net of inventory valuation adjustments [2]	$ (14)	$ 26	$ 50	$ 50
Equity-indexed compensation expense [3]	(17)	(16)	(36)	(39)
Net gain/(loss) on foreign currency revaluation	11	(4)	6	4
Tax effect on selected items impacting comparability	—	(1)	(9)	(6)
Other [4]	—	—	—	1
Selected items impacting comparability of net income attributable to PAA	$ (20)	$ 5	$ 11	$ 10
Impact to basic net income per limited partner unit	$ (0.06)	$ 0.02	$ 0.03	$ 0.02
Impact to diluted net income per limited partner unit	$ (0.05)	$ 0.01	$ 0.03	$ 0.02

[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, as applicable.

[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.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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,	
	2014	2013	2014	2013
Basic Adjusted Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 287	$ 292	$ 671	$ 821
Selected items impacting comparability of net income attributable to PAA (1)	20	(5)	(11)	(10)
Adjusted net income attributable to PAA	307	287	660	811
Less: General partner's incentive distribution (2)	(117)	(91)	(227)	(177)
Less: General partner 2% ownership (2)	(4)	(4)	(9)	(13)
Adjusted net income available to limited partners	186	192	424	621
Less: Undistributed earnings allocated and distributions to participating securities (2)	(1)	(1)	(3)	(4)
Adjusted limited partners' net income	$ 185	$ 191	$ 421	$ 617
Basic weighted average number of limited partner units outstanding	365	340	363	338
Basic adjusted net income per limited partner unit	$ 0.51	$ 0.56	$ 1.16	$ 1.83
Diluted Adjusted Net Income per Limited Partner Unit				
Net income attributable to PAA	$ 287	$ 292	$ 671	$ 821
Selected items impacting comparability of net income attributable to PAA (1)	20	(5)	(11)	(10)
Adjusted net income attributable to PAA	307	287	660	811
Less: General partner's incentive distribution (2)	(117)	(91)	(227)	(177)
Less: General partner 2% ownership (2)	(4)	(4)	(9)	(13)
Adjusted net income available to limited partners	186	192	424	621
Less: Undistributed earnings allocated and distributions to participating securities (2)	(1)	(1)	(3)	(3)
Adjusted limited partners' net income	$ 185	$ 191	$ 421	$ 618
Diluted weighted average number of limited partner units outstanding	367	342	365	341
Diluted adjusted net income per limited partner unit	$ 0.50	$ 0.56	$ 1.15	$ 1.82

(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.

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,	
	2014	2013	2014	2013
Net Income to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") and Excluding Selected Items Impacting Comparability ("Adjusted EBITDA") Reconciliations				

	Three Months Ended June 30, 2014	2013	Six Months Ended June 30, 2014	2013
Net Income	$ 288	$ 300	$ 672	$ 837
Add: Interest expense, net	82	75	161	152
Add: Income tax expense	22	18	70	70
Add: Depreciation and amortization	100	91	196	173
EBITDA	$ 492	$ 484	$ 1,099	$ 1,232
Selected items impacting comparability of EBITDA [1]	20	(6)	(20)	(15)
Adjusted EBITDA	$ 512	$ 478	$ 1,079	$ 1,217

[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,	
	2014	2013	2014	2013
Adjusted EBITDA to Implied Distributable Cash Flow (“DCF”)				
Adjusted EBITDA	$ 512	$ 478	$ 1,079	$ 1,217
Interest expense, net	(82)	(75)	(161)	(152)
Maintenance capital	(48)	(39)	(95)	(82)
Current income tax expense	(16)	(8)	(52)	(53)
Equity earnings in unconsolidated entities, net of distributions	2	(1)	7	(1)
Distributions to noncontrolling interests [1]	(1)	(13)	(2)	(25)
Implied DCF	$ 367	$ 342	$ 776	$ 904

[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,	
	2014	2013	2014	2013
Cash Flow from Operating Activities Reconciliation				
EBITDA	$ 492	$ 484	$ 1,099	$ 1,232
Current income tax expense	(16)	(8)	(52)	(53)
Interest expense, net	(82)	(75)	(161)	(152)
Net change in assets and liabilities, net of acquisitions	(287)	(70)	9	232
Other items to reconcile to cash flows from operating activities:				
Equity-indexed compensation expense	34	27	68	78
Net cash provided by operating activities	$ 141	$ 358	$ 963	$ 1,337

PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING STATEMENTS OF OPERATIONS

(in millions, except per share data)

	Three Months Ended June 30, 2014			Six Months Ended June 30, 2014		
	PAA	Consolidating Adjustments [1]	PAGP	PAA	Consolidating Adjustments [1]	PAGP
REVENUES	$ 11,195	$ —	$ 11,195	$ 22,878	$ —	$ 22,878
COSTS AND EXPENSES						
Purchases and related costs	10,280	—	10,280	20,950	—	20,950
Field operating costs	360	—	360	696	—	696
General and administrative expenses	90	1	91	179	2	181
Depreciation and amortization	100	—	100	196	1	197
Total costs and expenses	10,830	1	10,831	22,021	3	22,024
OPERATING INCOME	365	(1)	364	857	(3)	854
OTHER INCOME/(EXPENSE)						
Equity earnings in unconsolidated entities	23	—	23	44	—	44
Interest expense, net	(82)	(3)	(85)	(161)	(5)	(166)
Other income/(expense), net	4	—	4	2	—	2
INCOME BEFORE TAX	310	(4)	306	742	(8)	734
Current income tax expense	(16)	—	(16)	(52)	—	(52)
Deferred income tax expense	(6)	(9)	(15)	(18)	(17)	(35)
NET INCOME	288	(13)	275	672	(25)	647
Net income attributable to noncontrolling interests	(1)	(259)	(260)	(1)	(617)	(618)
NET INCOME ATTRIBUTABLE TO PAGP	$ 287	$ (272)	$ 15	$ 671	$ (642)	$ 29
BASIC AND DILUTED NET INCOME PER CLASS A SHARE			$ 0.11			$ 0.21

BASIC AND DILUTED WEIGHTED AVERAGE CLASS A SHARES OUTSTANDING	136	135

(1) Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATING BALANCE SHEET DATA
(in millions)

	June 30, 2014		
	PAA	**Consolidating Adjustments [1]**	**PAGP**
ASSETS			
Current assets	$ 5,168	$ 2	$ 5,170
Property and equipment, net	11,613	21	11,634
Goodwill	2,502	—	2,502
Linefill and base gas	895	—	895
Long-term inventory	287	—	287
Investments in unconsolidated entities	545	—	545
Other, net	485	1,076	1,561
Total assets	$ 21,495	$ 1,099	$ 22,594
LIABILITIES AND PARTNERS’ CAPITAL			
Current liabilities	$ 5,423	$ 1	$ 5,424
Senior notes, net of unamortized discount	7,409	—	7,409
Long-term debt under credit facilities and other	5	526	531
Other long-term liabilities and deferred credits	546	—	546
Total liabilities	13,383	527	13,910
Partners’ capital excluding noncontrolling interests	8,053	(7,007)	1,046
Noncontrolling interests	59	7,579	7,638
Total partners’ capital	8,112	572	8,684
Total liabilities and partners’ capital	$ 21,495	$ 1,099	$ 22,594

(1) Represents the aggregate consolidating adjustments necessary to produce consolidated financial statements for PAGP.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
DISTRIBUTION SUMMARY (unaudited)

Q2 2014 PAGP DISTRIBUTION SUMMARY
(in millions, except per unit and per share data)

	Q2 2014 [1]
PAA Distribution/LP Unit	$ 0.6450
GP Distribution/LP Unit	$ 0.3312
Total Distribution/LP Unit	$ 0.9762
PAA LP Units Outstanding at 8/1/14	369
Gross GP Distribution	$ 128
Less: IDR Reduction	(6)
Net Distribution from PAA to AAP	$ 122
Less: Debt Service	(2)
Less: G&A Expense	(1)
Less: Other	—

Cash Available for Distribution by AAP	$	119
Distributions to AAP Partners		
Direct AAP Owners & AAP Management (79.1% economic interest)	$	94
PAGP (20.9% economic interest)		25
Total distributions to AAP Partners	$	119
Distribution to PAGP Investors	$	25
PAGP Class A Shares Outstanding at 8/1/14		136
PAGP Distribution/Class A Share	$	0.18340

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(1) Amounts may not recalculate due to rounding.

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PLAINS GP HOLDINGS AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

COMPUTATION OF BASIC AND DILUTED NET INCOME PER CLASS A SHARE
(in millions, except per share data)

	Three Months Ended June 30, 2014	Six Months Ended June 30, 2014
Basic and Diluted Net Income per Class A Share		
Net income attributable to PAGP	$ 15	$ 29
Basic and diluted weighted average number of Class A shares outstanding	136	135
Basic and diluted net income per Class A share	$ 0.11	$ 0.21

Contacts:

Ryan Smith
Director, Investor Relations
(866) 809-1291

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

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