

PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
May 07, 2014

**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) **May 7, 2014**

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)

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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))
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Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated May 7, 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 first 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 second quarter and second half of 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 Second Quarter and Second Half 2014 Guidance

We based our guidance for the three-month period ending June 30, 2014 and the six-month period 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 May 6, 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 3 Months Ended Mar 31, 2014		3 Months Ending Jun 30, 2014		Guidance (a) 6 Months Ending Dec 31, 2014		12 Months Ending Dec 31, 2014	
	Low	High	Low	High	Low	High	Low	High
Segment Profit								
Net revenues (including equity earnings from unconsolidated entities)	\$ 1,034	\$ 877	\$ 912	\$ 1,942	\$ 1,977	\$ 3,853	\$ 3,923	
Field operating costs	(336)	(372)	(362)	(701)	(691)	(1,409)	(1,389)	
General and administrative expenses	(89)	(89)	(84)	(163)	(158)	(341)	(331)	
	609	416	466	1,078	1,128	2,103	2,203	
Depreciation and amortization expense	(96)	(99)	(95)	(192)	(184)	(387)	(375)	
Interest expense, net	(78)	(86)	(82)	(180)	(172)	(344)	(332)	
Income tax expense	(48)	(6)	(4)	(55)	(47)	(109)	(99)	
Other income / (expense), net	(2)					(2)	(2)	
Net Income	385	225	285	651	725	1,261	1,395	
Net income attributable to noncontrolling interests	(1)	(1)	(1)	(1)	(1)	(3)	(3)	
Net Income Attributable to PAA	\$ 384	\$ 224	\$ 284	\$ 650	\$ 724	\$ 1,258	\$ 1,392	
Net Income to Limited Partners (b)	\$ 268	\$ 105	\$ 164	\$ 389	\$ 461	\$ 762	\$ 893	
Basic Net Income Per Limited Partner Unit (b)								
Weighted Average Units Outstanding	360	365	365	369	369	366	366	
Net Income Per Unit	\$ 0.74	\$ 0.28	\$ 0.44	\$ 1.05	\$ 1.24	\$ 2.07	\$ 2.43	
Diluted Net Income Per Limited Partner Unit (b)								
Weighted Average Units Outstanding	363	367	367	371	371	368	368	
Net Income Per Unit	\$ 0.73	\$ 0.28	\$ 0.44	\$ 1.04	\$ 1.23	\$ 2.05	\$ 2.41	
EBIT	\$ 511	\$ 317	\$ 371	\$ 886	\$ 944	\$ 1,714	\$ 1,826	
EBITDA	\$ 607	\$ 416	\$ 466	\$ 1,078	\$ 1,128	\$ 2,101	\$ 2,201	

Selected Items Impacting

Comparability

Equity-indexed compensation expense	\$ (19)	\$ (14)	\$ (14)	\$ (25)	\$ (25)	\$ (58)	\$ (58)	
Tax effect on selected items impacting comparability	(9)					(9)	(9)	
Net gain / (loss) on foreign currency revaluation	(5)					(5)	(5)	
Gains / (losses) from derivative activities, net of inventory valuation adjustments	65					65	65	
Selected Items Impacting Comparability of Net Income attributable to PAA	\$ 32	\$ (14)	\$ (14)	\$ (25)	\$ (25)	\$ (7)	\$ (7)	

Excluding Selected Items Impacting

Comparability

Adjusted Segment Profit								
Transportation	\$ 213	\$ 200	\$ 210	\$ 477	\$ 487	\$ 890	\$ 910	
Facilities	159	131	141	300	310	590	610	
Supply and Logistics	194	99	129	326	356	619	679	
Other income, net	1					1	1	
Adjusted EBITDA	\$ 567	\$ 430	\$ 480	\$ 1,103	\$ 1,153	\$ 2,100	\$ 2,200	

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Adjusted Net Income Attributable to PAA	\$	352	\$	238	\$	298	\$	675	\$	749	\$	1,265	\$	1,399
Basic Adjusted Net Income Per Limited Partner Unit (b)	\$	0.65	\$	0.32	\$	0.48	\$	1.11	\$	1.31	\$	2.08	\$	2.44
Diluted Adjusted Net Income Per Limited Partner Unit (b)	\$	0.65	\$	0.32	\$	0.48	\$	1.10	\$	1.30	\$	2.07	\$	2.43

(a) The projected average foreign exchange rate is \$1.10 Canadian to \$1.00 U.S. for the three-month period ending June 30, 2014. The rate as of May 6, 2014 was \$1.09 Canadian to \$1.00 U.S. A \$0.05 change in the FX rate will impact adjusted EBITDA for the nine months ending December 31, 2014 by approximately \$18 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, <i>general partner</i> or <i>GP</i> 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 Three Months Ended Mar 31, 2014	Three Months Ending Jun 30, 2014	Guidance Six Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
Average Daily Volumes (MBbls/d)				
Crude Oil Pipelines				
All American	33	40	35	36
Bakken Area Systems	131	150	150	145
Basin/Mesa	745	760	760	756
Capline	126	140	160	147
Eagle Ford Area Systems	189	215	250	226
Line 63 / 2000	125	95	130	120
Manito	45	45	45	45
Mid-Continent Area Systems	315	355	385	360
Permian Basin Area Systems	760	755	770	764
Rainbow	120	110	115	115
Rangeland	69	55	65	63
Salt Lake City Area Systems	131	130	135	133
South Saskatchewan	64	55	55	57
White Cliffs	23	25	30	27
Other	661	695	780	729
NGL Pipelines				
Co-Ed	57	60	60	59
Other	116	120	110	114
	3,710	3,805	4,035	3,896
Trucking	130	145	145	141
	3,840	3,950	4,180	4,037
Segment Profit per Barrel (\$/Bbl)				
Excluding Selected Items Impacting Comparability	\$ 0.62	\$ 0.57(1)	\$ 0.63(1)	\$ 0.61(1)

(1) Mid-point of guidance.

b. *Facilities.* Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, NGL and natural gas, as well as NGL fractionation and isomerization services 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) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) fees from NGL fractionation and isomerization and (vi) 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.

	Actual Three Months Ended Mar 31, 2014	Three Months Ending Jun 30, 2014	Guidance Six 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	94	95	95
Rail Load / Unload Volumes (MBbls/d)	229	280	305	280
Natural Gas Storage (Bcf/Mo.)	97	100	100	99
NGL Fractionation (MBbls/d)	92	105	100	100
Facilities Activities Total				
Avg. Capacity (MMBbls/Mo.) (1)	121	122	124	123
Segment Profit per Barrel (\$/Bbl)				
Excluding Selected Items Impacting Comparability	\$ 0.44	\$ 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 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 June 30, 2014 reflect the current market structure and for the six-month and twelve-month periods ending December 31, 2014 reflect seasonal, 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 Three Months Ended Mar 31, 2014	Three Months Ending Jun 30, 2014	Guidance Six Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
Average Daily Volumes (MBbls/d)				
Crude Oil Lease Gathering Purchases	893	940	985	951
NGL Sales	273	130	200	200
Waterborne Cargos				
	1,166	1,070	1,185	1,151
Segment Profit per Barrel (\$/Bbl)				
Excluding Selected Items Impacting Comparability	\$ 1.85	\$ 1.17(1)	\$ 1.56(1)	\$ 1.54(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 \$1.85 billion for expansion projects with an additional \$185 to \$205 million for maintenance capital projects. During the first three months of 2014, we spent \$563 million and \$46 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	\$470
• Cactus Pipeline	330
• Rail Terminal Projects (1)	215
• Ft. Sask Facility Projects / NGL Line	160
• Eagle Ford JV Project	70
• Western Oklahoma Extension	65
• Mississippian Lime Pipeline	50
• White Cliffs Expansion	40
• Line 63 Reactivation	40
• Natural Gas Storage Expansions	25
• Other Projects	385

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	\$1,850
Potential Adjustments for Timing / Scope Refinement (2)	- \$100 + \$100
Total Projected Expansion Capital Expenditures	\$1,750 - \$1,950
Maintenance Capital Expenditures	\$185 - \$205

(1) Includes projects located in or near Bakersfield, CA, Carr, CO, Van Hook, ND and Western 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 March 31, 2014 and adjusted for estimated equity issuances under our continuous offering program and the \$700 million of 4.7% 30-year senior notes issued in April 2014.

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 April 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 \$5 million and \$104 million for the three-month period ending June 30, 2014 and twelve-month period ending December 31, 2014, respectively, of which approximately \$2 million is classified as a current income tax benefit and \$78 million as a current income tax expense, respectively. For the twelve-month period ending December 31, 2014 we expect to have a deferred tax expense of \$26 million. All or part of the annual income tax expense of \$104 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 May 6, 2014, estimated vesting dates range from May 2014 to August 2019 and annualized benchmark distribution levels range from \$1.925 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 April 7, 2014, we declared an annualized distribution of \$2.52 payable on May 15, 2014 to our unitholders of record as of May 2, 2014. For the purposes of guidance, we have made the assessment that a \$2.75 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of \$55 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, including the timing of such grant issuances. For example, a \$2 change in the unit price would change the second-quarter equity-indexed compensation expense by approximately \$5 million and the full year equity-indexed compensation expense by approximately \$6 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 ended March 31, 2014, the three-month period ending June 30, 2014 and the six and twelve-month periods ending December 31, 2014.

Actual 3 Months	3 Months Ending	Guidance 6 Months Ending	12 Months Ending
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	Ended Mar 31, 2014		Jun 30, 2014		Dec 31, 2014		Dec 31, 2014							
			Low	High	Low	High	Low	High						
Reconciliation to EBITDA and Adjusted EBITDA														
Net Income	\$	385	\$	225	\$	285	\$	651	\$	725	\$	1,261	\$	1,395
Interest expense, net		78		86		82		180		172		344		332
Income tax expense		48		6		4		55		47		109		99
EBIT		511		317		371		886		944		1,714		1,826
Depreciation and amortization		96		99		95		192		184		387		375
EBITDA	\$	607	\$	416	\$	466	\$	1,078	\$	1,128	\$	2,101	\$	2,201
Selected Items Impacting Comparability of EBITDA		(40)		14		14		25		25		(1)		(1)
Adjusted EBITDA	\$	567	\$	430	\$	480	\$	1,103	\$	1,153	\$	2,100	\$	2,200

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

	Actual Three Months Ended Mar 31, 2014	Three Months Ending Jun 30, 2014	Mid-Point Guidance Six Months Ending Dec 31, 2014	Twelve Months Ending Dec 31, 2014
	(in millions)			
Adjusted EBITDA	\$ 567	\$ 455	\$ 1,128	\$ 2,150
Interest expense, net	(78)	(84)	(176)	(338)
Current income tax (expense) / benefit	(36)	2	(44)	(78)
Maintenance capital expenditures	(46)	(50)	(99)	(195)
Other, net	4	(2)	(1)	1
Implied DCF	\$ 411	\$ 321	\$ 808	\$ 1,540

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);
- 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;
- 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;
- weather interference with business operations or project construction, including the impact of extreme weather events or conditions;
- the effectiveness of our risk management activities;
- shortages or cost increases of supplies, materials or labor;
- 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: May 7, 2014

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