UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

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

Date of Report (Date of earliest event reported) **November 4, 2013**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

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

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

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

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

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

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

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

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

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

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated November 4, 2013

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

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its third-quarter 2013 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01, we are also providing detailed guidance for financial performance for the fourth quarter and full year 2013 as well as preliminary guidance for calendar 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 Fourth Quarter 2013 Guidance and Full Year 2014 Preliminary Guidance

We based our guidance for the three-month and twelve-month periods ending December 31, 2013 on assumptions and estimates that we believe are reasonable, given our assessment of historical trends (modified for changes in market conditions), business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as NGL sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so we can provide no assurance that actual performance will fall within the guidance ranges. Please refer to information under the caption Forward-Looking Statements and Associated Risks below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of November 3, 2013. We undertake no obligation to publicly update or revise any forward-looking statements.

To supplement our financial information presented in accordance with GAAP, management uses additional measures known as non-GAAP financial measures in its evaluation of past performance and prospects for the future. Management believes that the presentation of such additional financial measures provides useful information to investors regarding our financial condition and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operations and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income represents one of the two most directly comparable GAAP measures to EBIT and EBITDA. In Note 9 below, we reconcile net income to EBIT and EBITDA for the 2013 guidance periods presented. Cash flows from operating activities is the other most comparable GAAP measure. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA, because such reconciliations are impractical for forecasted periods. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliations), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. 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 9 Months Ended Sep 30, 2013	Guidance (a) 3 Months Ending December 31, 2013 Low	High	12 Months Ending December 31, 2013 Low	High
Segment Profit					
Net revenues (including equity earnings from unconsolidated entities)	$ 2,926	$ 924	$ 959	$ 3,850	$ 3,885
Field operating costs	(1,010)	(332)	(322)	(1,342)	(1,332)
General and administrative expenses	(276)	(86)	(81)	(362)	(357)
	1,640	506	556	2,146	2,196
Depreciation and amortization expense	(265)	(97)	(92)	(362)	(357)
Interest expense, net	(224)	(81)	(77)	(305)	(301)
Income tax expense	(79)	(30)	(26)	(109)	(105)
Other income / (expense), net	2	1	1	3	3
Net Income	**1,074**	**299**	**362**	**1,373**	**1,436**
Net income attributable to noncontrolling interests	(22)	(9)	(9)	(31)	(31)
Net Income Attributable to Plains	**$ 1,052**	**$ 290**	**$ 353**	**$ 1,342**	**$ 1,405**
Net Income to Limited Partners (b)	$ 764	$ 185	$ 247	$ 949	$ 1,011
Basic Net Income Per Limited Partner Unit (b)					
Weighted Average Units Outstanding	340	344	344	341	341
Net Income Per Unit	$ 2.23	$ 0.54	$ 0.72	$ 2.77	$ 2.95
Diluted Net Income Per Limited Partner Unit (b)					
Weighted Average Units Outstanding	342	346	346	343	343
Net Income Per Unit	$ 2.22	$ 0.53	$ 0.71	$ 2.75	$ 2.93
EBIT	**$ 1,377**	**$ 410**	**$ 465**	**$ 1,787**	**$ 1,842**
EBITDA	**$ 1,642**	**$ 507**	**$ 557**	**$ 2,149**	**$ 2,199**
Selected Items Impacting Comparability					
Equity-indexed compensation expense	$ (51)	$ (15)	$ (15)	$ (66)	$ (66)
Tax effect on selected items impacting comparability	8			8	8
Net gain on foreign currency revaluation	5			5	5
Gains / (losses) from derivative activities, net of inventory valuation adjustments	(9)	2	2	(7)	(7)
Other	3			3	3
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (44)	$ (13)	$ (13)	$ (57)	$ (57)
Excluding Selected Items Impacting Comparability					
Adjusted Segment Profit					
Transportation	$ 547	$ 213	$ 223	$ 760	$ 770
Facilities	459	144	154	603	613
Supply and Logistics	685	162	192	847	877
Other income, net	6	1	1	7	7

Adjusted EBITDA	$	1,697	$	520	$	570	$	2,217	$	2,267
Adjusted Net Income Attributable to Plains	$	1,096	$	303	$	366	$	1,399	$	1,462
Basic Adjusted Net Income Per Limited Partner Unit (b)	$	2.36	$	0.57	$	0.75	$	2.94	$	3.12
Diluted Adjusted Net Income Per Limited Partner Unit (b)	$	2.35	$	0.57	$	0.75	$	2.92	$	3.09

(a) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three-month period ending December 31, 2013.The rate as of November 1, 2013 was $1.00 Canadian to $0.96 U.S. A $0.05 change in the FX rate will impact annual adjusted EBITDA by approximately $8 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
General partner (GP)	As the context requires, general partner or GP refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.

2. *Operating Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. The following is a brief explanation of the operating activities for each segment as well as key metrics.

a. *Transportation.* Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. Our transportation segment also includes our equity earnings from our investments in Settoon Towing and the White Cliffs, Butte, Frontier and Eagle Ford pipeline systems, in which we own non-controlling interests.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and assumed completion of internal growth projects. Actual volumes will be influenced by maintenance schedules at refineries, production trends, weather and other natural occurrences 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	
	Nine Months Ended Sep 30, 2013	Three Months Ending Dec 31, 2013	Twelve Months Ending Dec 31, 2013
Average Daily Volumes (MBbls/d)			
Crude Oil / Refined Products Pipelines			
All American	39	40	39
Bakken Area Systems	130	145	134
Basin/Mesa	712	745	720
Capline	153	145	151
Eagle Ford Area Systems	81	205	112
Line 63 / 2000	113	105	111
Manito	46	50	47
Mid-Continent Area Systems	277	300	283
Permian Basin Area Systems	540	695	579
Rainbow	125	125	125
Rangeland	59	60	59
Salt Lake City Area Systems	132	130	131
South Saskatchewan	50	55	51
White Cliffs	22	20	21
Other	825	725	800
NGL Pipelines			
Co-Ed	55	55	55
Other	190	170	185
	3,549	3,770	3,603
Trucking	113	125	116
	3,662	3,895	3,719
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.55	$ 0.61(1)	$ 0.56(1)

(1) Mid-point of guidance.

b. *Facilities*. Our Facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, natural gas and NGL, NGL fractionation and isomerization services and natural gas and condensate processing services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements.

Revenues generated in this segment include (i) storage fees that are generated when we lease storage capacity, (ii) terminal throughput fees that are generated when we receive crude oil, refined products or NGL from one connecting source and redeliver the applicable product to another connecting carrier, (iii) loading and unloading fees at our rail terminals, (iv) hub service fees associated with natural gas park and loan activities, interruptible storage services and wheeling and balancing services, (v) revenues from the sale of natural gas, (vi) fees from NGL fractionation and isomerization and (vii) fees from gas and condensate processing services. Adjusted segment profit is forecasted using the volume assumptions in the table below, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

	Actual	Guidance	
	Nine Months Ended Sep 30, 2013	Three Months Ending Dec 31, 2013	Twelve Months Ending Dec 31, 2013
Operating Data			
Crude Oil, Refined Products, and NGL Terminalling and Storage (MMBbls/Mo.)	94	95	94
Rail Load / Unload Volumes (MBbl/d)	221	265	232
Natural Gas Storage (Bcf/Mo.)	96	97	96
NGL Fractionation (MBbls/d)	99	100	99
Facilities Activities Total Avg. Capacity (MMBbls/Mo.) (1)	120	122	120
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 0.43	$ 0.41(2)	$ 0.42(2)

(1) Calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes, multiplied by the number of days in the period and divided by the number of months in the period; (iii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes, multiplied by the number of days in the period and divided by the number of months in the period.

(2) Mid-point of guidance.

c. *Supply and Logistics*. Our Supply and Logistics segment operations generally consist of the following merchant-related activities:

- the purchase of U.S. and Canadian crude oil at the wellhead, the bulk purchase of crude oil at pipeline, terminal and rail facilities, and the purchase of cargos at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of NGL;
- the purchase of NGL from producers, refiners, processors and other marketers;
- the resale or exchange of crude oil and NGL at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil and NGL on trucks, barges, railcars, pipelines and ocean-going vessels from various delivery points, market hub locations or directly to end users such as refineries, processors and fractionation facilities.

We characterize a substantial portion of our baseline profit generated by our Supply and Logistics segment as fee equivalent. This portion of the segment profit is generated by the purchase and resale of crude oil on an index-related basis, which results in us generating a gross margin for such activities. This gross margin is reduced by the transportation, facilities and other logistical costs associated with delivering the crude oil to market as well as any operating and general and administrative expenses. The level of profit associated with a portion of the other activities we conduct in the Supply and Logistics segment is influenced by overall market structure and the degree of volatility in the crude oil market, as well as variable operating expenses. Forecasted operating results for the three-month period ending December 31, 2013 reflect the current market structure and seasonal, weather-related variations in NGL sales. Variations in weather, market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast adjusted segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory, based on current and anticipated market conditions. Actual volumes are influenced by temporary market-driven storage and withdrawal of oil, maintenance schedules at refineries, actual production levels, weather, and other external factors beyond our control. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location and quality differentials as well as contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	Actual	Guidance	
	Nine Months Ended Sep 30, 2013	Three Months Ending Dec 31, 2013	Twelve Months Ending Dec 31, 2013
Average Daily Volumes (MBbl/d)			
Crude Oil Lease Gathering Purchases	855	885	863
NGL Sales	196	240	207
Waterborne Cargos	5	5	5
	1,056	1,130	1,075
Segment Profit per Barrel ($/Bbl)			
Excluding Selected Items Impacting Comparability	$ 2.37	$ 1.70(1)	$ 2.20(1)

(1) Mid-point of guidance.

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, forecasted capital expenditures and projected in-service dates. Depreciation may vary due to gains and losses on intermittent sales of assets, asset retirement obligations, asset impairments or foreign exchange rates.

4. *Capital Expenditures and Acquisitions.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions that we may commit to after the date hereof. We forecast capital expenditures during calendar 2013 to be approximately $1.65 billion for expansion projects with an additional $165 to $185 million for maintenance capital projects. During the first nine months of 2013, we invested $1,253 million and $124 million for expansion and maintenance projects, respectively. The following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2013:

	Calendar 2013 (in millions)
Expansion Capital	
• Mississippian Lime Pipeline	$175
• Rainbow II Pipeline	135
• Gulf Coast Pipeline	110
• Yorktown Terminal Projects	110
• Eagle Ford Area Pipeline Projects	90
• Rail Terminal Projects (1)	85
• White Cliffs Expansion	75
• Cactus Pipeline	70
• Eagle Ford JV Project	60
• Fort Saskatchewan Facility Expansions	60
• St. James Terminal Projects	55
• Western Oklahoma Extension	55
• Spraberry Area Pipeline Projects	50
• PAA Natural Gas Storage (Multiple Projects)	44
• Cushing Terminal Projects	35
• Gulf Coast Gas Processing Facility Enhancements	35
• Shafter Expansion	30
• Other Projects (2)	376

	$1,650
Potential Adjustments for Timing / Scope Refinement (3)	- $50 + $75
Total Projected Expansion Capital Expenditures	$1,600 - $1,725
Maintenance Capital Expenditures	$165 - $185

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

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

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

5. *Capital Structure.* This guidance is based on our capital structure as of September 30, 2013 and adjusted for estimated equity issuances under our continuous offering program. Also assumed in our guidance is that we expect to repay our $250 million 5.625% senior notes that mature December 15, 2013 with short-term borrowings from our credit facility as a result of prefunding during 2012 (equity and retained cash flow), accordingly these notes are classified as short-term on our balance sheet at September 30, 2013.

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated capital expenditures for maintenance and expansion projects, anticipated equity proceeds from the continuous offering program, expected timing of collections and payments and forecasted levels of inventory and other working capital sources and uses. Interest rate assumptions for variable-rate debt are based on the LIBOR curve as of late October.

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 and NGL and include it in purchases and related costs.

7. *Income Taxes*. We expect our Canadian income tax expense to be approximately $28 million and $107 million for the three-month and twelve-month periods ending December 31, 2013, respectively, of which approximately $23 million and $92 million, respectively, is classified as current income tax expense. For the twelve-month period ending December 31, 2013 we expect to have a deferred tax expense of $15 million. All or part of the income tax expense of $107 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 November 4, 2013, estimated vesting dates range from November 2013 to August 2019 and annualized benchmark distribution levels range from $1.925 to $2.85. For some awards, a percentage of any units remaining unvested as of a certain date will vest on such date and all others will be forfeited.

On October 1, 2013, we declared an annualized distribution of $2.40 payable on November 14, 2013 to our unitholders of record as of November 1, 2013. For the purposes of guidance, we have made the assessment that a $2.65 distribution level is probable of occurring, and accordingly, guidance includes an accrual over the applicable service period at an assumed market price of $53.00 per unit as well as an accrual associated with awards that will vest on a certain date. The actual amount of equity-indexed compensation expense in any given period will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the vesting date, (iii) the probability assessment regarding distributions, and (iv) new equity-indexed compensation award grants. For example, a $2.00 change in the unit price would change the fourth-quarter equity-indexed compensation expense by approximately $4 million. Therefore, actual net income could differ from our projections.

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

	Guidance			
	3 Months Ending December 31, 2013		**12 Months Ending December 31, 2013**	
	Low	**High**	**Low**	**High**

Reconciliation to EBITDA				
Net Income	$ 299	$ 362	$ 1,373	$ 1,436
Interest expense, net	81	77	305	301
Income tax expense	30	26	109	105
EBIT	410	465	1,787	1,842
Depreciation and amortization	97	92	362	357
EBITDA	$ 507	$ 557	$ 2,149	$ 2,199
Selected Items Impacting Comparability of EBITDA	13	13	68	68
Adjusted EBITDA	**$ 520**	**$ 570**	**$ 2,217**	**$ 2,267**

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

	Mid-Point Guidance	
	Three Months Ending December 31, 2013	**Twelve Months Ending December 31, 2013**
Adjusted EBITDA	$ 545	$ 2,242
Interest expense, net	(79)	(303)
Current income tax expense	(23)	(92)
Distributions to noncontrolling interests	(12)	(50)
Maintenance capital expenditures	(51)	(175)
Other, net	(1)	(8)
Implied DCF	$ 379	$ 1,614

Preliminary 2014 Guidance

Our preliminary adjusted EBITDA guidance for 2014 is based on (i) operating and financial performance of our existing assets that is assumed to be generally in line with recent performance trends, appropriately adjusted for known and expected developments as well as estimated market conditions and (ii) contributions from expansion capital projects and recent acquisitions in line with our expectations. In addition, our preliminary 2014 guidance does not include any forecast for acquisitions that we may commit to after the date hereof. The following table summarizes the range of selected key financial data of our preliminary guidance for calendar year 2014.

Preliminary Calendar 2014 Guidance (in millions) (1)

	Low	**High**
Adjusted EBITDA	$ 2,100	$ 2,250
Interest expense, net	(350)	(340)
Current income tax benefit (expense)	(70)	(60)
Maintenance capital expenditures	(205)	(185)
Other, net	(10)	(5)
Implied DCF	$ 1,465	$ 1,660
Expansion Capital	$ 1,300	$ 1,500

(1) Assumes PAA s proposed acquisition of the publicly traded units of PAA Natural Gas Storage is completed as of

January 1, 2014, resulting in the issuance of 14.7 million common units of PAA as well as an incremental $12 million reduction in the general partner s incentive distribution rights related to such transaction is implemented in 2014.

Our preliminary guidance for interest expense is based on our capital structure as of September 30, 2013 and adjusted for estimated equity issuances under our continuous equity offering program, approved capital projects for 2013, and the assumption that 2014 capital projects will range between $1.3 billion and $1.5 billion. Our preliminary guidance for maintenance capital expenditures is based on our estimated average level of recurring expenditures of approximately $195 million. Our preliminary guidance for adjusted net income and adjusted EBITDA does not include a forecast of selected items impacting comparability, such as equity compensation expense, as it is impractical to forecast such items.

Forward-Looking Statements and Associated Risks

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

- failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our access to capital;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the effectiveness of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to or slowdown in the development of additional oil and gas reserves or other factors;

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

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- the availability of, and our ability to consummate, acquisition or combination opportunities;

- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- non-utilization of our assets and facilities;
- the effects of competition;
- interruptions in service on third-party pipelines;
- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- the currency exchange rate of the Canadian dollar;
- weather interference with business operations or project construction;
- risks related to the development and operation of our facilities;
- factors affecting demand for natural gas and natural gas storage services and rates;
- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

We undertake no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in our filings with the Securities and Exchange Commission, which information is incorporated by reference herein.

SIGNATURES

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

	PLAINS ALL AMERICAN PIPELINE, L.P.		
	By:	PAA GP LLC, its general partner	
	By:	PLAINS AAP, L. P., its sole member	
	By:	PLAINS ALL AMERICAN GP LLC, its general partner	
Date: November 4, 2013	By:	/s/ Charles Kingswell-Smith	
		Name:	Charles Kingswell-Smith
		Title:	*Vice President and Treasurer*