

PLAINS ALL AMERICAN PIPELINE LP  
Form 8-K  
February 11, 2009

**UNITED STATES SECURITIES AND EXCHANGE  
COMMISSION**

Washington, D.C. 20549

**FORM 8-K**

**CURRENT REPORT**

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

**Date of Report (Date of earliest event reported) February 11, 2009**

**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**

## Edgar Filing: PLAINS ALL AMERICAN PIPELINE LP - Form 8-K

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

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

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

**Item 9.01. Financial Statements and Exhibits**

(d) Exhibit 99.1 Press Release dated February 11, 2009.

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

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its fourth-quarter and annual 2008 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01 we are providing detailed guidance for financial performance for the first quarter of calendar 2009 and for the full year. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this Item 7.01 shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

**Disclosure of First Quarter and Full Year 2009 Guidance**

EBIT and EBITDA (each as defined below in Note 1 to the Operating and Financial Guidance table) are non-GAAP financial measures. Net income and cash flows from operating activities are the most directly comparable GAAP measures to EBIT and EBITDA. In Note 10 below, we reconcile EBITDA and EBIT to net income for the 2009 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for a forecasted period. We encourage you to visit our website at [www.paalp.com](http://www.paalp.com) (in particular the section entitled Non-GAAP Reconciliation), which presents a historical reconciliation of certain commonly used non-GAAP financial measures, including EBIT and EBITDA. We present EBIT and EBITDA because we believe they provide additional information with respect to both the performance of our fundamental business activities and our ability to meet our future debt service, capital expenditures and working capital requirements. We also believe that debt holders commonly use EBITDA to analyze partnership performance. In addition, we have highlighted the impact of our equity compensation plans on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three-month period ending March 31, 2009 and twelve-month period ending December 31, 2009 is based 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 LPG sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so no assurance can be provided that actual performance will fall within the guidance ranges. Please refer to information under the caption Forward-Looking Statements and Associated Risks below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of February 10, 2009. We undertake no obligation to publicly update or revise any forward-looking statements.

Plains All American Pipeline, L.P.

Operating and Financial Guidance

(in millions, except per unit data)

	2009 Guidance (1)			
	3 Months Ending March 31,		12 Months Ending December 31,	
	Low	High	Low	High
<b>Segment Profit</b>				
Net revenues (including equity earnings from unconsolidated entities)	\$ 444	\$ 458	\$ 1,753	\$ 1,788
Field operating costs	(170)	(166)	(664)	(654)
General and administrative expenses	(48)	(46)	(189)	(184)
	226	246	900	950
Depreciation and amortization expense	(57)	(55)	(232)	(226)
Interest expense, net	(54)	(52)	(214)	(207)
Income tax expense	(3)	(2)	(11)	(8)
Other income (expense), net	2	2	6	6
<b>Net Income</b>	<b>\$ 114</b>	<b>\$ 139</b>	<b>\$ 449</b>	<b>\$ 515</b>
Net Income to Limited Partners	\$ 81	\$ 106	\$ 312	\$ 375
Basic Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	123	123	123	123
Net Income Per Unit	\$ 0.66	\$ 0.86	\$ 2.54	\$ 3.05
Diluted Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	124	124	124	124
Net Income Per Unit	\$ 0.65	\$ 0.85	\$ 2.52	\$ 3.02
<b>EBIT</b>	<b>\$ 171</b>	<b>\$ 193</b>	<b>\$ 674</b>	<b>\$ 730</b>
<b>EBITDA</b>	<b>\$ 228</b>	<b>\$ 248</b>	<b>\$ 906</b>	<b>\$ 956</b>

<b>Selected Items Impacting Comparability</b>							
Equity compensation charge	\$	(7)	\$	(7)		(29)	(29)
<b>Excluding Selected Items Impacting Comparability</b>							
Adjusted Segment Profit							
Transportation	\$	107	\$	112	\$	476	\$ 488
Facilities		43		46		195	203
Marketing		83		95		258	288
Other Income (Expense), net		2		2		6	6
Adjusted EBITDA	\$	235	\$	255	\$	935	\$ 985
Adjusted Net Income	\$	121	\$	146	\$	478	\$ 544
Adjusted Basic Net Income per Limited Partner Unit	\$	0.72	\$	0.92	\$	2.76	\$ 3.28
Adjusted Diluted Net Income per Limited Partner Unit	\$	0.71	\$	0.91	\$	2.73	\$ 3.25

---

(1) The projected average foreign exchange rate is \$1.18 CAD to \$1 USD. The rate as of February 10, 2009 was \$1.25 CAD to \$1 USD. A \$0.10 change in the fx rate will impact annual EBITDA by approximately \$12 million.

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
Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
FX	Foreign currency exchange
General partner (GP)	As the context requires, <i>general partner</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.
Class B units	Class B units of Plains AAP, L.P.

2. *Business Segments.* We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. 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 refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. We also include in this segment our equity earnings from our non-controlling interest in the Butte and Frontier pipeline systems and Settoon Towing.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. Segment profit is forecast 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 pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

Edgar Filing: PLAINS ALL AMERICAN PIPELINE LP - Form 8-K

	2009 Guidance	
	Three Months Ending March 31,	Twelve Months Ending December 31,
Average Daily Volumes (000 Bbls/d)		
All American	43	43
Basin	360	360
Capline	210	220
Line 63 / 2000	140	140
Salt Lake City Area Systems (1) (2)	140	145
West Texas / New Mexico Area Systems (1)	365	360
Rainbow	200	200
Manito	70	70
Rangeland	60	55
Refined Products	115	115
Other	1,157	1,217
	2,860	2,925
Trucking	100	110
	2,960	3,035
Average Segment Profit (\$/Bbl)		
Excluding Selected Items Impacting Comparability	\$ 0.41(3)	\$ 0.44(3)

(1) The aggregate of multiple systems in the respective areas.

(2) With the completion of the new expansion project, reported volumes will increase approximately 40,000 Bbl/d. However, not all of the increase is incremental volume.

(3) 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 and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. This segment also includes our equity earnings from our 50% investment in PAA/Vulcan Gas Storage, LLC, which owns and operates approximately 31 Bcf of underground natural gas storage capacity and is constructing an additional projected 19 Bcf of underground storage capacity.

Segment profit is forecast 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.

	2009 Guidance	
	Three Months Ending March 31,	Twelve Months Ending December 31,
Operating Data		
Crude oil, refined products and LPG storage (MMBbls/Mo.)	56	57
Natural Gas Storage (Bcf/Mo.)	16	19
LPG Processing (MBbl/d)	18	18
Facilities Activities Total (1)		

Edgar Filing: PLAINS ALL AMERICAN PIPELINE LP - Form 8-K

Avg. Capacity (MMBbls/Mo.)	59	61
Segment Profit per Barrel (\$/Bbl)		
Excluding Selected Items Impacting Comparability	\$ 0.25(2)	\$ 0.27(2)

---

(1) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to barrel of crude oil ratio; and (iii) LPG processing 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. *Marketing*. Our marketing segment operations generally consist of the following merchant activities:

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of LPG;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

The level of profit in the marketing segment is influenced by overall market structure and the degree of volatility in the crude oil market as well as variable operating expenses. Forecasted operating results for the three-month period ending March 31, 2009 reflect the current market structure and seasonal, weather-related variations in LPG sales. Variations in market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast 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. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location, quality and contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	<b>2009 Guidance</b>	
	<b>Three Months Ending March 31,</b>	<b>Twelve Months Ending December 31,</b>
Average Daily Volumes (MBbl/d)		
Crude Oil Lease Gathering	640	640
LPG Sales	165	105
Refined Products	30	30
Waterborne foreign crude imported	75	75
	910	850
Segment Profit per Barrel (\$/Bbl)		
Excluding Selected Items Impacting Comparability	\$ 1.09(1)	\$ 0.88(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 is computed using the straight-line method over estimated useful lives, which range from 3 years (for office furniture and equipment) to 40 years (for certain pipelines, crude oil terminals and facilities). Depreciation may vary during any one period due to gains

and losses on intermittent sales of assets, asset retirement obligations, or asset impairments.

4. *Selected Items Impacting Comparability.* Our actual results will reflect certain mark-to-market items such as gains and losses related to derivative activities, gains and losses from unrealized foreign currency transactions, and inventory revaluation adjustments. Our adjusted results exclude these selected items impacting comparability until such time that the underlying and offsetting physical transaction settles. Although the economics of these transactions as a whole are embedded in our guidance presented here, our selected items impacting comparability do not reflect these items as there is no accurate way to forecast the magnitude and timing. The timing of when these items will impact our results is primarily dependent on the timing of the purchase or sale of the underlying inventory which is dependent on market variables and other factors. The magnitude of these items is dependent on market prices and exchange rates at a point in time. As such, our actual results could differ materially from our projections.

5. *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 may be made after the date hereof. Capital expenditures during calendar 2009 are forecasted to be approximately \$295 million for expansion projects with an additional \$70 to \$80 million for maintenance projects. Following are some of the more notable projects and forecasted expenditures for the year:

	Calendar 2009 (in millions)	
Expansion Capital		
• St. James Phase III (1)		\$85
• Kerrobert pumping project		34
• Cushing - Phase VII		29
• Rangeland tankage and connections		29
• Nipisi storage and truck terminal		20
• Patoka Phase II		20
• Paulsboro tankage		13
• Other projects, including acquisition related expansion projects (2)		65
		295
Maintenance Capital	\$70	\$80
Total Projected Capital Expenditures (excluding acquisitions)	\$365	\$375

(1) Includes a dock and condensate tanks.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2008.

6. *Capital Structure.* This guidance is based on our capital structure as of December 31, 2008.
7. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, forecasted capital expenditures for maintenance and expansion projects, expected timing of collections and payments, and forecasted levels of inventory and other working capital sources and uses. Interest rate assumptions for variable rate debt are based on the current forward LIBOR curve.

Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, deferred amounts associated with terminated interest-rate hedges and interest on short-term debt for non-contango inventory (primarily hedged LPG inventory and New York Mercantile Exchange and IntercontinentalExchange margin deposits). Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for inventory stored in a contango market. We treat interest on contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

8. *Net Income per Unit.* Basic net income per limited partner unit is calculated by dividing net income allocated to limited partners by the basic weighted average units outstanding during the period.

	Guidance (in millions, except per unit data)			
	Three Months Ending March 31, 2009		Twelve Months Ending December 31, 2009	
	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:				
Net Income	\$ 114	\$ 139	\$ 449	\$ 515
General partner's incentive distribution	(36)	(36)	(151)	(151)
General partner's incentive distribution reduction	5	5	19	19
General partner 2% ownership	(2)	(2)	(5)	(8)
Net income available to limited partners	\$ 81	\$ 106	\$ 312	\$ 375
Denominator:				
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units				
	123	123	123	123
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units				
	124	124	124	124
Basic net income per limited partner unit	\$ 0.66	\$ 0.86	\$ 2.54	\$ 3.05
Diluted net income per limited partner unit	\$ 0.65	\$ 0.85	\$ 2.52	\$ 3.02

In conjunction with the Pacific and Rainbow acquisitions, the general partner reduced the amounts due it as incentive distributions by an aggregate amount of \$75 million. Approximately \$38 million of this reduction was realized as of December 31, 2008. Incentive distributions will be reduced by \$21 million in 2009, \$11 million in 2010 and \$5 million in 2011.

The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Based on the current number of units outstanding, each \$0.05 per unit annual increase or decrease in the distribution relative to forecasted amounts decreases or increases, respectively, net income available for limited partners by approximately \$6 million (\$0.05 per unit) on an annualized basis.

9. *Equity Compensation Plans.* The majority of grants outstanding under our equity compensation plans (LTIP and Class B units) contain vesting criteria that are based on a combination of performance benchmarks and service period. The grants will vest in various percentages, typically on the later to occur of specified earliest vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of February 10, 2009, estimated vesting dates range from May 2009 to January 2016 and minimum

## Edgar Filing: PLAINS ALL AMERICAN PIPELINE LP - Form 8-K

annualized distribution levels range from \$2.80 to \$4.50. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012 and all others are forfeited.

On January 14, 2009, we declared an annualized distribution of \$3.57 payable on February 13, 2009 to our unitholders of record as of February 3, 2009. We have made the assessment that a \$3.75 distribution level is probable of occurring and accordingly, for grants that vest at annualized distribution levels of \$3.75 or less, guidance includes an accrual over the applicable service period at an assumed market price of \$40.00 per unit as well as the fair value associated with awards that will vest on a date certain. The actual amount of equity compensation expense amortization 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 date of actual vesting, (iii) the amount of the amortization in the early years, (iv) the probability assessment of achieving future distribution rates, and (v) new equity compensation award grants. For example, a \$3.00 change in the unit price assumption at March 31, 2009 would change the first-quarter equity compensation expense by approximately \$2 million. Therefore, actual net income

could differ materially from our projections.

10. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the three-month and twelve month guidance ranges ending March 31, 2009 and December 31, 2009, respectively, for EBITDA and EBIT to net income.

	Three Months Ending March 31, 2009		Twelve Months Ending December 31, 2009	
	Low	High	Low	High
	(in millions)		(in millions)	
<b>Reconciliation to Net Income</b>				
EBITDA	\$ 228	\$ 248	\$ 906	\$ 956
Depreciation and amortization	57	55	232	226
EBIT	171	193	674	730
Interest expense	54	52	214	207
Income tax expense	3	2	11	8
Net Income	\$ 114	\$ 139	\$ 449	\$ 515

#### 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 identified by the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. The absence of these 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 are reasonable assumptions. Certain factors could cause actual results to differ materially from results anticipated in the forward-looking statements. These factors include, but are not limited to:

- failure to implement or capitalize on planned internal growth projects;
- 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 success of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;
- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;
- shortages or cost increases of power supplies, materials or labor;
- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;
- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- our ability to obtain debt or equity financing on satisfactory terms to fund expansion projects,

working capital requirements and the repayment or refinancing of indebtedness;

- the future performance of acquired assets and businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- unanticipated changes in crude oil market structure and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations and interpretations;
- the effects of competition;
- interruptions in service and fluctuations in tariffs or volumes on third-party pipelines;
- increased costs or lack of availability of insurance;
- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;
- the currency exchange rate of the Canadian dollar;
- weather interference with business operations or project construction;
- risks related to the development and operation of natural gas storage facilities;
- future developments and circumstances at the time distributions are declared;
- general economic, market or business conditions and the amplification of other risks caused by deteriorated financial markets, capital constraints and pervasive liquidity concerns; and
- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

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



**SIGNATURES**

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

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC, its general partner

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

By: PLAINS ALL AMERICAN GP LLC, its general partner

Date: February 11, 2009

By: /s/ AL SWANSON

Name: Al Swanson  
Title: *Senior Vice President and  
Chief Financial Officer*