PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 04, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 8-K
CURRENT REPORT
Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934
Date of Report (Date of earliest event reported) August 4, 2010
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))

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Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 Press Release dated August 4, 2010.

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

Plains All American Pipeline, L.P. (the Partnership) today issued a press release reporting its second-quarter 2010 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 third and fourth quarters of calendar 2010 and updating our previous guidance for financial performance for the full calendar year of 2010 (which supersedes guidance pertaining to 2010 contained in our Form 8-K furnished on May 5, 2010). 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 Third and Fourth Quarter 2010 Guidance; Update of Full Year 2010 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 9 below, we reconcile net income to EBIT and EBITDA for the 2010 guidance periods presented. We do not, however, reconcile cash flows from operating activities to EBIT and EBITDA because such reconciliations are impractical for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled Non-GAAP Reconciliation), which presents a historical reconciliation of EBIT and EBITDA as well as certain other commonly used non-GAAP financial measures. 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, gains and losses from other derivative activities, net loss on early repayment of senior notes, and PNGS contingent consideration fair value adjustment on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

We based our guidance for the three months ending September 30 and December 31, 2010 and twelve months ending December 31, 2010 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 August 3, 2010. 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)

	Actual	Guidance [1]					
	6 Months Ended 6/30/2010	3 Months Ending September 30, 2010 Low	3 Months Ending September 30, 2010 High	3 Months Ending December 31, 2010 Low	3 Months Ending December 31, 2010 High	12 Months Ending December 31, 2010 Low	12 Months Ending December 31, 2010 High
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 987	$ 470	$ 488	$ 492	$ 510	$ 1,949	$ 1,985
Field operating costs	(334)	(184)	(179)	(175)	(170)	(693)	(683)
General and administrative expenses	(117)	(54)	(52)	(54)	(52)	(225)	(221)
	536	232	257	263	288	1,031	1,081
Depreciation and amortization expense	(131)	(63)	(61)	(61)	(59)	(255)	(251)
Interest expense, net	(120)	(67)	(65)	(64)	(62)	(251)	(247)
Income tax expense		(1)		(1)		(2)	
Other income (expense), net	(1)	(6)	(6)			(7)	(7)
Net Income	**$ 284**	**$ 95**	**$ 125**	**$ 137**	**$ 167**	**$ 516**	**$ 576**
Less: Net income attributable to the noncontrolling interest	(2)	(3)	(3)	(3)	(3)	(8)	(8)
Net Income attributable to Plains	**$ 282**	**$ 92**	**$ 122**	**$ 134**	**$ 164**	**$ 508**	**$ 568**
Net Income to Limited Partners	$ 201	$ 51	$ 80	$ 90	$ 120	$ 342	$ 401
Basic Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	136	136	136	136	136	136	136
Net Income Per Unit	$ 1.45	$ 0.36	$ 0.57	$ 0.65	$ 0.87	$ 2.47	$ 2.90
Diluted Net Income Per Limited Partner Unit							
Weighted Average Units Outstanding	137	137	137	137	137	137	137
Net Income Per Unit	$ 1.45	$ 0.35	$ 0.57	$ 0.65	$ 0.86	$ 2.46	$ 2.90
EBIT	**$ 404**	**$ 163**	**$ 190**	**$ 202**	**$ 229**	**$ 769**	**$ 823**
EBITDA	**$ 535**	**$ 226**	**$ 251**	**$ 263**	**$ 288**	**$ 1,024**	**$ 1,074**

Selected Items Impacting Comparability							
Equity compensation charge	$ (24)	$ (8)	$ (8)	$ (7)	$ (7)	$ (39)	$ (39)
Inventory Valuation Adjustments Net of Gains/(Losses) from related derivative activities	(1)					(1)	(1)
Gains / (Losses) from other derivative activities	41					41	41
Net loss on early repayment of senior notes		(6)	(6)			(6)	(6)
PNGS contingent consideration fair value adjustment	(2)					(2)	(2)
	$ 14	$ (14)	$ (14)	$ (7)	$ (7)	$ (7)	$ (7)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 269	$ 132	$ 137	$ 143	$ 148	$ 544	$ 554
Facilities	134	68	72	65	69	267	275
Supply and Logistics	120	40	56	62	78	222	254
Other Income (Expense), net	(2)					(2)	(2)
Adjusted EBITDA	$ 521	$ 240	$ 265	$ 270	$ 295	$ 1,031	$ 1,081
Adjusted Net Income attributable to Plains	$ 268	$ 106	$ 136	$ 141	$ 171	$ 515	$ 575
Adjusted Basic Net Income per Limited Partner Unit	$ 1.35	$ 0.46	$ 0.67	$ 0.70	$ 0.92	$ 2.51	$ 2.94
Adjusted Diluted Net Income per Limited Partner Unit	$ 1.34	$ 0.45	$ 0.67	$ 0.70	$ 0.91	$ 2.50	$ 2.93

(1) The projected average foreign exchange rate is $1.05 Canadian dollar to $1 U.S. Dollar, for the remainder of 2010. The rate as of August 3, 2010 was

$1.024 Canadian dollar to $1 U.S. Dollar. A $0.10 change in the FX rate will impact forecasted EBITDA for the last six months of 2010 by approximately $7 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, general partner 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. *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 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. Our transportation segment also includes our equity earnings from our investments in the Butte and Frontier pipeline systems and Settoon Towing, in which we own noncontrolling 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 declines, weather and other natural disasters 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 pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

			2010	
	Actual		Guidance	
	Six Months Ended June 30,	Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Average Daily Volumes (000 Bbls/d)				
All American	41	40	40	41
Basin	363	395	390	378

Capline	203	260	250	229
Line 63 / 2000	111	110	115	112
Salt Lake City Area Systems [1]	132	140	135	135
West Texas / New Mexico Area Systems [1]	376	400	385	384
Rainbow	195	185	190	191
Manito	60	60	60	60
Rangeland	51	50	50	51
Refined Products	121	120	120	120
Other	1,193	1,210	1,185	1,195
	2,846	2,970	2,920	2,896
Trucking	92	90	90	91
	2,938	3,060	3,010	2,987
Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability	$ 0.51	$ 0.48[2]	$ 0.53[2]	$ 0.50[2]

[1] The aggregate of multiple systems in the respective areas.

[2] Mid-point of guidance.

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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, LPG and natural gas, 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.

Adjusted 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.

		2010 Guidance		
	Actual Six Months Ended June 30,	Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Operating Data				
Crude oil, refined products and LPG storage (MMBbls/Mo.)	60	62	62	61
Natural Gas Storage (Bcf/Mo.)	45	50	50	48
LPG Processing (MBbl/d)	13	19	18	16
Facilities Activities Total [1] Avg. Capacity (MMBbls/Mo.)	68	71	71	69
Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability	$ 0.33	$ 0.33[2]	$ 0.32[2]	$ 0.32[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. *Supply and Logistics*. Our supply and logistics segment operations generally consist of the following activities:

- the purchase of 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 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 remainder of 2010 reflect the current market structure and seasonal, weather-related variations in LPG sales. The fourth quarter of 2010 reflects our expectation of normal winter weather for our LPG business. 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, production declines, 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, 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.

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	Actual	2010 Guidance		
	Six Months Ended June 30,	Three Months Ending September 30,	Three Months Ending December 31,	Twelve Months Ending December 31,
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering Purchases	611	625	610	614
LPG Sales	94	72	164	106
Refined Products Sales	41	48	58	47
Waterborne foreign crude oil imported	73	70	65	70
	819	815	897	837
Segment Profit per Barrel ($/Bbl) Excluding Selected Items Impacting Comparability	$ 0.81	$ 0.60[1]	$ 0.95[1]	$ 0.78[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 during any one period due to gains and losses on intermittent sales of assets, asset retirement obligations, asset impairments or foreign exchange rates.

4. *Acquisitions and Other Capital Expenditures.* Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated estimates do not include any forecasts for acquisitions to which we may commit after the date hereof. We forecast capital expenditures during calendar 2010 to be approximately $360 million for expansion projects with an additional $85 million for maintenance capital projects. During the first six months of 2010, we spent $163 million and $33 million, respectively, for expansion and maintenance projects. Following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2010:

	Calendar 2010 (in millions)
Expansion Capital	
PAA Natural Gas Storage	95
Patoka Phase III	18
West Texas gathering lines	18
Cushing Phase VII	17
Edmonton land purchase	16
St. James Phase III	15
Cushing Phase VIII	15
Wichita Falls tanks	11
Other projects[(1)]	155

	360
Maintenance Capital	85
Total Projected Capital Expenditures (excluding acquisitions)	445

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

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5. *Capital Structure.* This guidance is based on our capital structure as of June 30, 2010, as adjusted to give effect to the issuance on July 14, 2010 of $400 million of 3.95% 5-year senior notes as well as the anticipated redemption in September of our $175 million 6.25% senior notes due 2015.

6. *Interest Expense.* Debt balances are projected based on estimated cash flows, estimated distribution rates, estimated 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.

7. *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.

	Actual	Guidance[1]					
	6 Months Ended	3 Months Ending September 30, 2010		3 Months Ending December 31, 2010		12 Months Ending December 31, 2010	
	6/30/2010	Low	High	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:							
Net Income attributable to Plains	$ 282	$ 92	$ 122	$ 134	$ 164	$ 508	$ 568
Less: General partners incentive distribution paid (1)	(77)	(40)	(40)	(42)	(42)	(159)	(159)
Subtotal	205	52	82	92	122	349	409
Less: General partner 2% ownership (1)	(4)	(2)	(2)	(2)	(2)	(7)	(8)
Net income available to limited partners	201	51	80	90	120	342	401
Adjustment in accordance with application of the two-class method for MLPs (1)	(3)	(2)	(2)	(1)	(2)	(6)	(7)
Net income available to limited partners in accordance with application of the	$ 198	$ 49	$ 78	$ 89	$ 118	$ 336	$ 394

two-class method for MLPs							
Denominator:							
Basic weighted average number of limited partner units	136	136	136	136	136	136	136
Effect of dilutive securities:							
Weighted average LTIP units	1	1	1	1	1	1	1
Diluted weighted average number of limited partner units	137	137	137	137	137	137	137
Basic net income per limited partner unit	$ 1.45	$ 0.36	$ 0.57	$ 0.65	$ 0.87	$ 2.47	$ 2.90
Diluted net income per limited partner unit	$ 1.45	$ 0.35	$ 0.57	$ 0.65	$ 0.86	$ 2.46	$ 2.90

(1) We calculate net income to our general partner based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). However, FASB guidance requires that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized within

the earnings per unit calculation. After adjusting for this distribution, the remaining undistributed earnings or excess distribution over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement for earnings per unit calculation purposes. We reflect the impact of the difference in (i) the distribution utilized and (ii) the calculation of the excess 2% general partner interest as the Adjustment in accordance with application of the two-class method for MLP s.

In conjunction with the Pacific, Rainbow and PNGS acquisitions, our general partner reduced the amounts due it as incentive distributions by an aggregate amount of $83 million. Approximately $68.75 million of this reduction was realized as of June 30, 2010. Incentive distributions will be reduced by $7.0 million for the balance of 2010 ($3.75 million and $3.25 million, respectively, for third quarter and fourth quarter 2010) and $7.25 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 net income available for limited partners by approximately $7.0 million ($0.05 per unit) on an annualized basis.

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8. *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 vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of August 4, 2010, estimated vesting dates range from August 2010 to May 2019 and annualized distribution levels range from $3.50 to $4.50. For some awards, a percentage of any units remaining unvested as of a date certain will vest on such date and all others will be forfeited.

   On July 13, 2010, we declared an annualized distribution of $3.77 payable on August 13, 2010 to our unitholders of record as of August 3, 2010. We have made the assessment that a $3.90 distribution level is probable of occurring and accordingly, for grants that vest at annualized distribution levels of $3.90 or less, guidance includes an accrual over the applicable service period at an assumed market price of $59.00 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 vesting date, (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 September 30, 2010 would change the third-quarter equity compensation expense by approximately $5 million. Therefore, actual net income could differ materially from our projections. Similarly, if an assessment was made that a $4.00 distribution level was probable, third-quarter equity compensation expense would increase by approximately $27 million (approximately $26 million for the cumulative effect of prior service periods and approximately $1 million for the current service period amortization).

9. *Reconciliation of Net Income to EBIT and EBITDA.* The following table reconciles net income to EBIT and EBITDA, for the three-month guidance periods ending September 30 and December 31, 2010 and twelve-month guidance period ending December 31, 2010.

	Guidance					
	3 Months Ending September 30, 2010		**3 Months Ending December 31, 2010**		**12 Months Ending December 31, 2010**	
	Low	**High**	**Low**	**High**	**Low**	**High**
Reconciliation to EBITDA						
Net Income	$ 95	$ 125	$ 137	$ 167	$ 516	$ 576
Interest expense	67	65	64	62	251	247
Income tax expense	1		1		2	
EBIT	163	190	202	229	769	823
Depreciation and amortization	63	61	61	59	255	251
EBITDA	$ 226	$ 251	$ 263	$ 288	$ 1,024	$ 1,074

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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, inte forecast, as well as similar expressions and statements regarding our business strategy, plans and objectives 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 to be 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 effectiveness 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;

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 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;

unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related 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;

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

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SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC, its general partner

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

By: PLAINS ALL AMERICAN GP LLC, its general partner

Date: August 4, 2010

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

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