PLAINS ALL AMERICAN PIPELINE LP
Form 8-K
August 03, 2011

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 3, 2011**

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

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

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

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

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

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

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

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

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

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

Item 9.01. **Financial Statements and Exhibits**

(d) Exhibit 99.1 Press Release dated August 3, 2011.

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 2011 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. We are providing detailed guidance for financial performance for the third and fourth quarters of calendar 2011. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under Item 2.02 and Item 7.01 shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of Third Quarter and Fourth Quarter 2011 Guidance

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 10 below, we reconcile net income to EBIT and EBITDA for the 2011 guidance periods presented. Cash flow 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 a forecasted period. 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. In addition, we have highlighted the impact of (i) equity compensation expense, (ii) gains from other derivative activities, (iii) net loss on early repayment of senior notes, and (iv) other immaterial selected items impacting comparability. Due to the nature of the selected items, certain of the selected items impacting comparability may impact certain non-GAAP financial measures but not impact other non-GAAP financial measures.

We based our guidance for the three-month period ending September 30, 2011 and the three-month and twelve-month periods ending December 31, 2011 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 2, 2011. 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 6/30/2011	**3 Months Ending September 30, 2011 Low**	**3 Months Ending September 30, 2011 High**	**3 Months Ending December 31, 2011 Low**	**3 Months Ending December 31, 2011 High**	**12 Months Ending December 31, 2011 Low**	**12 Months Ending December 31, 2011 High**
Segment Profit							
Net revenues (including equity earnings from unconsolidated entities)	$ 1,277	$ 590	$ 612	$ 607	$ 629	$ 2,474	$ 2,518
Field operating costs	(420)	(229)	(223)	(224)	(218)	(873)	(861)
General and administrative expenses	(143)	(63)	(61)	(64)	(62)	(270)	(266)
	714	298	328	319	349	1,331	1,391
Depreciation and amortization expense	(126)	(62)	(59)	(62)	(59)	(250)	(244)
Interest expense, net	(128)	(65)	(62)	(66)	(63)	(259)	(253)
Income tax benefit (expense)	(22)	(7)	(5)	(7)	(5)	(36)	(32)
Other income (expense), net	(20)	1	1	1	1	(18)	(18)
Net Income	**418**	**165**	**203**	**185**	**223**	**768**	**844**
Less: Net income attributable to noncontrolling interests	(10)	(8)	(6)	(10)	(8)	(28)	(24)
Net Income attributable to Plains	**$ 408**	**$ 157**	**$ 197**	**$ 175**	**$ 215**	**$ 740**	**$ 820**
Net Income to Limited Partners	$ 305	$ 103	$ 142	$ 118	$ 157	$ 523	$ 601
Basic Net Income Per Limited Partner Unit (2)							
Weighted Average Units Outstanding	146	149	149	149	149	148	148
Net Income Per Unit	$ 2.04	$ 0.67	$ 0.93	$ 0.78	$ 1.04	$ 3.48	$ 4.03
Diluted Net Income Per Limited Partner Unit (2)							
Weighted Average Units Outstanding	147	150	150	150	150	148	148
Net Income Per Unit	$ 2.03	$ 0.66	$ 0.93	$ 0.77	$ 1.03	$ 3.46	$ 3.98
EBIT	**$ 568**	**$ 237**	**$ 270**	**$ 258**	**$ 291**	**$ 1,063**	**$ 1,129**
EBITDA	**$ 694**	**$ 299**	**$ 329**	**$ 320**	**$ 350**	**$ 1,313**	**$ 1,373**
Selected Items Impacting Comparability							
Equity compensation expense	$ (33)	$ (11)	$ (11)	$ (10)	$ (10)	$ (54)	$ (54)
Gains from other derivative activities	41					41	41
Net loss on early repayment of senior notes	(23)					(23)	(23)
Other, net (3)	(3)	1	1	1	1	(1)	(1)
Selected Items Impacting Comparability of Net Income attributable to Plains	$ (18)	$ (10)	$ (10)	$ (9)	$ (9)	$ (37)	$ (37)
Excluding Selected Items Impacting Comparability							
Adjusted Segment Profit							
Transportation	$ 280	$ 140	$ 148	$ 149	$ 157	$ 569	$ 585
Facilities	177	90	94	93	97	360	368
Supply and Logistics	253	79	97	87	105	419	455
Other income, net	4	1	1	1	1	6	6
Adjusted EBITDA	$ 714	$ 310	$ 340	$ 330	$ 360	$ 1,354	$ 1,414

Adjusted Net Income attributable to Plains	$	426	$	167	$	207	$	184	$	224	$	777	$	857
Adjusted Basic Net Income per Limited Partner Unit	$	2.16	$	0.74	$	1.00	$	0.83	$	1.10	$	3.73	$	4.26
Adjusted Diluted Net Income per Limited Partner Unit	$	2.15	$	0.73	$	0.99	$	0.83	$	1.09	$	3.70	$	4.23

---

(1) The projected average foreign exchange rate is $1.00 Canadian to $1.00 U.S. for the three month period ending September 30, 2011 and $1.05 Canadian to $1.00 U.S. for the three month period ending December 31, 2011. The rate as of August 2, 2011 was $0.96 Canadian to $1.00 U.S. Dollar. A $0.05 change in the FX rate will impact EBITDA for the last six months of 2011 by approximately $5 million.

(2) Net income per unit has been calculated in accordance with FASB s requirement 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.

(3) Includes other immaterial selected items impacting comparability such as those impacting our subsidiary, PAA Natural Gas Storage, L.P. (PNG), as well as the noncontrolling interests portion of selected items.

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
FASB	Financial Accounting Standards Board
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.

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, Frontier and White Cliffs pipeline systems and Settoon Towing, 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 pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	Actual Six Months Ended Jun 30, 2011	Three Months Ending Sep 30, 2011	Guidance Three Months Ending Dec 31, 2011	Twelve Months Ending Dec 31, 2011
Average Daily Volumes (000 Bbls/d)				
All American	35	37	36	36
Basin	426	425	425	425
Capline	187	170	185	182
Line 63 / 2000	108	110	105	108
Salt Lake City Area Systems (1)	137	140	130	136
Permian Basin Area Systems (1)	398	405	415	404
Manito	67	70	60	66
Rainbow	151	70	135	127
Rangeland	55	55	60	56
Refined Products	97	90	85	92
Other	1,264	1,318	1,304	1,288
	2,925	2,890	2,940	2,920
Trucking	101	100	110	103
	3,026	2,990	3,050	3,023
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.51	$ 0.52(2)	$ 0.55(2)	$ 0.52(2)

(1) The aggregate of multiple systems in their respective areas.
(2) 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, 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.

	Actual Six Months Ended Jun 30, 2011	Three Months Ending Sep 30, 2011	Guidance Three Months Ending Dec 31, 2011	Twelve Months Ending Dec 31, 2011
Operating Data				
Crude oil, refined products and LPG storage (MMBbls/Mo.)	68	70	73	70
Natural Gas Storage (Bcf/Mo.)	67	75	75	71
LPG Processing (MBbl/d)	13	11	11	12
Facilities Activities Total (1)				
Avg. Capacity (MMBbls/Mo.)	80	83	86	82
Segment Profit per Barrel ($/Bbl)				
Excluding Selected Items Impacting Comparability	$ 0.37	$ 0.37(2)	$ 0.37(2)	$ 0.37(2)

(1) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by the gas to crude Btu equivalent ratio of 6 mcf of gas to 1 barrel of crude oil; and (iii) LPG processing volumes, in each case 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, the bulk purchase of crude oil at pipeline and terminal facilities, and 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.

We characterize a substantial portion of the 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 production at the wellhead 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 September 30, 2011 reflect the current market structure and, for the last six months of 2011, reflect the seasonal, weather-related variations in LPG 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, 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.

	Actual		**Guidance**	
	Six Months Ended Jun 30, 2011	**Three Months Ending Sep 30, 2011**	**Three Months Ending Dec 31, 2011**	**Twelve Months Ending Dec 31, 2011**
Average Daily Volumes (MBbl/d)				
Crude Oil Lease Gathering Purchases	722	720	725	722
LPG Sales	108	70	150	109
Waterborne cargos	28	40	20	29
	858	830	895	860
Segment Profit per Barrel ($/Bbl)				
	$ 1.63	$ 1.15(1)	$ 1.17(1)	$ 1.39(1)

Excluding Selected Items Impacting Comparability

---

(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 2011 to be approximately $625 million for expansion projects with an additional $95 to 105 million for maintenance capital projects. During the first six months of 2011, we spent $251 million and $52 million, respectively, for expansion and maintenance projects. Following are some of the more notable projects and forecasted expenditures for the year ending December 31, 2011:

	Calendar 2011 (in millions)		
Expansion Capital			
• PAA Natural Gas Storage (multiple projects)	$100		
• Cushing - Phases IX - XI	41		
• Rainbow II Pipeline	36		
• Basile Gas Processing Facility	35		
• Ross (Stanley) Rail Project	32		
• Eagle Ford Project	31		
• Bone Spring Expansion	25		
• Bumstead Facility	21		
• Patoka Phase IV	19		
• Mid-Continent Project	15		
• Nipisi Treater	13		
• Ridgelawn (Sidney) Propane Storage	13		
• Basin System Expansion	12		
• Other projects (1)	232		
	$625		
Potential Adjustments for Timing / Scope Refinement (2)	- $50		+ $25
Total Projected Expansion Capital Expenditures	$575	-	$650
Maintenance Capital	$95	-	$105

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2010.

(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 regulatory approvals and weather

5. *Capital Structure.* This guidance is based on our capital structure as of June 30, 2011.

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. *Income Taxes*. Effective January 1, 2011, our Canadian entities that were previously pass-through entities for Canadian tax purposes became taxpaying entities. For U.S. tax purposes, these entities will continue to be treated as pass-through entities. As a result of this and other related organizational modifications, we expect our Canadian income tax expense to increase to approximately $34 million, of which approximately $28 million is classified as current. In addition, withholding tax payments of approximately $10 million are estimated to be payable in 2011. Such withholding payments will reduce distributable cash flow. Both the Canadian income tax expense of $34 million and the $10 million of withholding tax may result in a tax credit to our equity holders and the $10 million of withholding tax will be reflected as a distribution in partners capital.

8. *Reconciliation of Adjusted EBITDA to Implied DCF.* The following table reconciles the mid-point of adjusted EBITDA to implied distributable cash flow for the three-month period ending September 30, 2011 and for the three-month and twelve-month periods ending December 31, 2011.

	Actual 6 Months Ended Jun 30, 2011	3 Months Ending Sep 30, 2011	Mid-Point Guidance 3 Months Ending Dec 31, 2011	12 Months Ending Dec 31, 2011
Adjusted EBITDA	$ 714	$ 325	$ 345	$ 1,384
Interest expense, net	(128)	(64)	(65)	(256)
Cash income taxes	(18)	(5)	(5)	(28)
Withholding taxes			(10)	(10)
Distributions to non-controlling interests	(23)	(11)	(11)	(45)
Maintenance capital expenditures	(52)	(24)	(24)	(100)
Other, net	5	(1)	(1)	3
Implied DCF	$ 498	$ 220	$ 229	$ 948

9. *Equity Compensation Plans.* The majority of grants outstanding under our various equity compensation plans contain vesting criteria that are based on a combination of performance benchmarks and service periods. The grants will vest in various percentages, typically on the later to occur of specified vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of August 3, 2011, estimated vesting dates range from August 2011 to May 2019 and annualized distribution levels range from $3.60 to $4.80. 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 11, 2011, we declared an annualized distribution of $3.93 payable on August 12, 2011 to our unitholders of record as of August 2, 2011. We have made the assessment that a $4.10 distribution level is probable of occurring, and accordingly, for grants that vest at annualized distribution levels of $4.10 or less, guidance includes an accrual over the applicable service period at an assumed market price of $64.00 per unit as well as an accrual 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 probability assessment regarding distributions, and (iv) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at September 30, 2011 would change the third-quarter equity compensation expense by approximately $5 million and the fourth-quarter equity compensation expense by approximately $6 million. Therefore, actual net income could differ materially from our projections. Similarly, if an assessment was made that a $4.20 distribution level was probable, third-quarter equity compensation expense would increase by approximately $7 million (approximately $6 million for the cumulative effect of prior service periods and approximately $1 million for the current service period amortization). Additionally, compensation expense for the three months ending December 31, 2011 would increase approximately $1 million.

10. *Reconciliation of Net Income to EBIT and EBITDA.* The following table reconciles net income to EBIT and EBITDA for the three-month period ending September 30, 2011 and for the three-month and twelve-month periods ending December 31, 2011.

	3 Months Ending September 30, 2011		Guidance 3 Months Ending December 31, 2011		12 Months Ending December 31, 2011	
	Low	High	Low	High	Low	High
	(in millions, except per unit amounts)					
Reconciliation to EBITDA						
Net Income	$ 165	$ 203	$ 185	$ 223	$ 768	$ 844
Interest expense	65	62	66	63	259	253
Income tax expense	7	5	7	5	36	32
EBIT	237	270	258	291	1,063	1,129

Depreciation and amortization		62		59		62		59		250		244
EBITDA	$	299	$	329	$	320	$	350	$	1,313	$	1,373

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 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;

- 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;

- 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 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;

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

- 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 natural gas storage facilities;
- factors affecting demand for natural gas and natural gas storage services and rates;
- 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.

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 3, 2011	By:	/s/ Charles Kingswell-Smith	
		Name:	Charles Kingswell-Smith
		Title:	*Vice President and Treasurer*