PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
November 08, 2006

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2006

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)
(713) 646-4100
(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes þ No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes þ No

At November 1, 2006, there were outstanding 80,994,178 Common Units.

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in millions, except units)

	September 30, 2006	December 31, 2005
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 10.3	$ 9.6
Trade accounts receivable and other receivables, net	1,441.5	781.0
Inventory	1,351.5	910.3
Other current assets	188.9	104.3
Total current assets	2,992.2	1,805.2
PROPERTY AND EQUIPMENT	2,682.1	2,116.1
Accumulated depreciation	(323.1)	(258.9)
	2,359.0	1,857.2
OTHER ASSETS		
Pipeline linefill in owned assets	204.1	180.2
Inventory in third party assets	77.0	71.5
Investment in PAA/Vulcan Gas Storage, LLC	125.7	113.5
Goodwill	183.3	47.4
Other, net	106.6	45.3
Total assets	$ 6,047.9	$ 4,120.3
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,822.9	$ 1,293.6
Due to related parties	7.9	6.8
Short-term debt	993.7	378.4
Other current liabilities	116.7	114.5
Total current liabilities	2,941.2	1,793.3
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	3.6	4.7

Senior notes, net of unamortized discount of $3.2 and $3.0, respectively	1,196.8	947.0
Other long-term liabilities and deferred credits	66.9	44.6
Total liabilities	4,208.5	2,789.6
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS CAPITAL		
Common unitholders (80,994,178 and 73,768,576 units outstanding at September 30, 2006 and December 31, 2005, respectively)	1,792.6	1,294.1
General partner	46.8	36.6
Total partners capital	1,839.4	1,330.7
	$ 6,047.9	$ 4,120.3

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(unaudited)		(unaudited)	
REVENUES				
Crude oil and LPG sales (includes buy/sell transactions of $4,442.8 million in the three months ended September 30, 2005 and $4,717.7 million and $11,630.0 million in the nine months ended September 30, 2006 and 2005, respectively)	$ 4,264.7	$ 8,387.1	$ 17,272.5	$ 21,724.4
Other gathering, marketing, terminalling and storage revenues	19.8	8.5	55.5	28.0
Pipeline margin activities revenues (includes buy/sell transactions of $52.2 million in the three months ended September 30, 2005 and $45.3 million and $125.8 million in the nine months ended September 30, 2006 and 2005, respectively)	174.6	209.8	542.3	542.3
Pipeline tariff activities revenues	66.7	59.0	183.3	168.9
Total revenues	4,525.8	8,664.4	18,053.6	22,463.6
COSTS AND EXPENSES				
Crude oil and LPG purchases and related costs (includes buy/sell transactions of $4,425.4 million in the three months ended September 30, 2005 and $4,749.4 million and $11,426.0 million in the nine months ended September 30, 2006 and 2005, respectively)	4,096.4	8,258.2	16,830.1	21,397.0
Pipeline margin activities purchases (includes buy/sell transactions of $47.1 million in the three months ended September 30, 2005 and $45.7 million and $115.9 million in the nine months ended September 30, 2006 and 2005, respectively)	167.6	206.5	521.3	525.5
Field operating costs	91.6	68.3	260.5	200.0
General and administrative expenses	33.0	26.5	92.2	74.8
Depreciation and amortization	24.2	20.0	67.1	58.1
Total costs and expenses	4,412.8	8,579.5	17,771.2	22,255.4
OPERATING INCOME	113.0	84.9	282.4	208.2
OTHER INCOME/(EXPENSE)				
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.3		2.2	

Interest expense (net of capitalized interest of $1.7 million and $0.5 million in the three months and $3.4 million and $1.5 million in the nine months ended September 30, 2006 and 2005, respectively)		(19.2)		(15.6)		(52.5)		(44.4)
Interest income and other income (expense), net		0.3		(0.3)		0.7		0.3
Income before cumulative effect of change in accounting principle		95.4		69.0		232.8		164.1
Cumulative effect of change in accounting principle						6.3		
NET INCOME	$	95.4	$	69.0	$	239.1	$	164.1
NET INCOME-LIMITED PARTNERS	$	84.6	$	63.9	$	212.7	$	150.8
NET INCOME-GENERAL PARTNER	$	10.8	$	5.1	$	26.4	$	13.3
BASIC NET INCOME PER LIMITED PARTNER UNIT								
Income before cumulative effect of change in accounting principle	$	0.90	$	0.81	$	2.37	$	2.11
Cumulative effect of change in accounting principle						0.08		
Net income	$	0.90	$	0.81	$	2.45	$	2.11
DILUTED NET INCOME PER LIMITED PARTNER UNIT								
Income before cumulative effect of change in accounting principle	$	0.89	$	0.79	$	2.35	$	2.07
Cumulative effect of change in accounting principle						0.08		
Net income	$	0.89	$	0.79	$	2.43	$	2.07
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		79.9		68.0		77.0		67.8
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		80.8		69.4		77.8		68.9

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Nine Months Ended September 30, 2006	2005
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 239.1	$ 164.1
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	67.1	58.1
Cumulative effect of change in accounting principle	(6.3)	
SFAS 133 mark-to-market adjustment	(14.8)	20.0
Long-Term Incentive Plan charge	27.1	16.9
Noncash amortization of terminated interest rate hedging instruments	1.2	1.2
Loss on foreign currency revaluation	2.1	1.4
Net cash paid for terminated interest rate hedging instruments		(0.9)
Equity earnings in PAA/Vulcan Gas Storage, LLC	(2.2)	
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(595.3)	(584.0)
Inventory	(414.6)	(470.9)
Accounts payable and other current liabilities	512.4	339.7
Due to related parties	2.3	4.9
Net cash used in operating activities	(181.9)	(449.5)
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 3)	(560.2)	(17.7)
Additions to property and equipment	(223.1)	(122.1)
Investment in unconsolidated affiliates	(10.0)	(112.5)
Cash paid for linefill in assets owned	(4.8)	
Proceeds from sales of assets	3.8	3.8
Net cash used in investing activities	(794.3)	(248.5)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on long-term revolving credit facility	(7.7)	(143.7)
Net borrowings on working capital revolving credit facility	55.3	62.2
Net borrowings on short-term letter of credit and hedged inventory facility	559.5	538.5
Proceeds from the issuance of senior notes	249.5	149.3
Net proceeds from the issuance of common units (Note 7)	315.6	236.2
Distributions paid to unitholders and general partner (Note 7)	(189.4)	(141.5)
Other financing activities	(6.6)	(6.9)
Net cash provided by financing activities	976.2	694.1

Effect of translation adjustment on cash	0.7	(0.9)
Net increase (decrease) in cash and cash equivalents	0.7	(4.8)
Cash and cash equivalents, beginning of period	9.6	13.0
Cash and cash equivalents, end of period	$ 10.3	$ 8.2
Cash paid for interest, net of amounts capitalized	$ 74.3	$ 53.2

The accompanying notes are an integral part of these consolidated financial statements.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
(in millions)

	Common Units		General Partner	Total Partners Capital
	Units	Amount	Amount	Amount
		(unaudited)		
Balance at December 31, 2005	**73.8**	**$ 1,294.1**	**$ 36.6**	**$ 1,330.7**
Net Income		212.7	26.4	239.1
Distributions		(164.0)	(25.4)	(189.4)
Issuance of common units	7.2	309.3	6.3	315.6
Other comprehensive income		140.5	2.9	143.4
Balance at September 30, 2006	**81.0**	**$ 1,792.6**	**$ 46.8**	**$ 1,839.4**

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(unaudited)		(unaudited)	
Net income	$ 95.4	$ 69.0	$ 239.1	$ 164.1
Other comprehensive income/(loss)	123.8	75.1	143.4	(21.8)
Comprehensive income	$ 219.2	$ 144.1	$ 382.5	$ 142.3

CONSOLIDATED STATEMENT OF
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2005	$ (16.6)	$ 87.1	$ 70.5
Current period activity:			
Reclassification adjustment for settled contracts	(5.4)		(5.4)
Changes in fair value of outstanding hedge positions	136.0		136.0
Currency translation adjustment		12.8	12.8
Total period activity	130.6	12.8	143.4

Balance at September 30, 2006	$ 114.0	$ 99.9	$ 213.9

The accompanying notes are an integral part of these consolidated financial statements.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1 Organization and Accounting Policies

Plains All American Pipeline, L.P. (PAA) is a Delaware limited partnership formed in September 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as LPG. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. In the third quarter of 2006 we completed an acquisition that represents our initial entry into the refined products transportation business (See Note 3). In addition, through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we are engaged in the development and operation of natural gas storage facilities. Investments in 50% or less owned affiliates, over which we have significant influence, such as PAA/Vulcan, are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with APB 18: *The Equity Method of Accounting for Investments in Common Stock*. An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

The accompanying consolidated financial statements and related notes present (i) our consolidated financial position as of September 30, 2006 and December 31, 2005, (ii) the results of our consolidated operations for the three months and nine months ended September 30, 2006 and 2005, (iii) our consolidated cash flows for the nine months ended September 30, 2006 and 2005, (iv) our consolidated changes in partners capital for the nine months ended September 30, 2006, (v) our consolidated comprehensive income for the three months and nine months ended September 30, 2006 and 2005, and (vi) our changes in consolidated accumulated other comprehensive income for the nine months ended September 30, 2006. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission. All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for the interim periods have been reflected. All significant intercompany transactions have been eliminated. Certain reclassifications are made to prior periods to conform to current period presentation. The results of operations for the nine months ended September 30, 2006 should not be taken as indicative of the results to be expected for the full year. The consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2005 Annual Report on Form 10-K.

Note 2 Trade Accounts Receivable

The majority of our trade accounts receivable relates to our gathering and marketing activities, which can generally be described as high volume and low margin activities. As is customary in the industry, a portion of these receivables is reflected net of payables to the same counterparty based on contractual agreements. We routinely review our trade accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered, received or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses, as well as our historical experience and the facts and circumstances surrounding certain aged balances, we have established an allowance for doubtful trade accounts receivable as shown below. At September 30, 2006, substantially all of our net trade accounts receivable were less than 60 days past the scheduled invoice date.

The following is a summary of the changes in our allowance for doubtful trade accounts receivable balance (in millions):

Balance at December 31, 2005	$ 0.8

Applied to accounts receivable balances		(0.3)
Charged to expense		0.1
Balance at September 30, 2006	$	0.6

We consider this reserve adequate; however, actual amounts may vary significantly from estimated amounts. The discovery of previously unknown facts or adverse developments affecting one or more of our counterparties or the industry as a whole could adversely impact our results of operations.

Note 3 Acquisitions

We completed six acquisitions during the first nine months of 2006 for aggregate consideration of approximately $567 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The aggregate purchase price is preliminary pending the resolution of working capital adjustments and the finalization of certain estimated transaction related costs. These acquisitions include (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the Andrews Acquisition), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana, (iii) interests in various crude oil pipeline systems in Canada and the U.S. including a 100% interest in the Bay Marchand-to-Ostrica-to-Alliance (BOA) Pipeline, various interests in the High Island Pipeline System (HIPS), and a 64.35% interest in the Clovelly-to-Meraux (CAM) Pipeline system, and (iv) three refined products pipeline systems from Chevron Pipe Line Company. The preliminary purchase price allocation is as follows (in millions):

Inventory	$ 35.1
Linefill	19.1
Inventory in third party assets	2.3
Property and equipment	327.4
Goodwill [(1)]	134.3
Intangibles	48.7
Net other assets and liabilities	(0.3)
	$ 566.6

(1) Represents the preliminary amount in excess of the fair value of the net assets acquired and is associated with our view of the future results of operations of the businesses acquired based on the strategic location of the assets and the growth opportunities that we expect to realize as we integrate these assets into our

existing
business
strategy.

Pro Forma Data

The following unaudited pro forma data is presented as if the acquisitions and related financings, in the aggregate, had occurred as of the beginning of the periods reported (in millions, except per unit amounts):

	Three Months Ended September 30,[1]		Nine Months Ended September 30,[1]	
	2006	**2005**	**2006**	**2005**
		(unaudited)		
Revenues	$4,530.3	$8,952.9	$ 18,634.9	$ 23,045.2
Income before cumulative effect of change in accounting principle	$ 98.3	$ 74.6	$ 252.1	$ 170.6
Net income	$ 98.3	$ 74.6	$ 258.4	$ 170.6
Basic income before cumulative effect of change in accounting principle per limited partner unit	$ 0.91	$ 0.79	$ 2.44	$ 2.03
Diluted income before cumulative effect of change in accounting principle per limited partner unit	$ 0.90	$ 0.78	$ 242	$ 2.00
Basic net income per limited partner unit	$ 0.91	$ 0.79	$ 2.52	$ 2.03
Diluted net income per limited partner unit	$ 0.90	$ 0.78	$ 2.49	$ 2.00

(1) The pro forma financial information was prepared based on historical financial information, where available, and in other cases, internally prepared estimates based on reasonable assumptions concerning historical data.

In June 2006, Plains entered into a purchase agreement with LB Pacific, the owner of the general partner of Pacific Energy Partners, LP (Pacific Energy), pursuant to which Plains has agreed, subject to the terms and conditions set forth in the purchase agreement, to purchase from LB Pacific (i) all of the issued and outstanding limited partner interest in Pacific Energy GP, LP, a Delaware limited partnership and the general partner of Pacific Energy, (ii) the sole member interest in Pacific Energy Management LLC, a Delaware limited liability company and the general partner of Pacific Energy GP, LP, (iii) approximately 5.2 million Pacific Energy common units and (iv) approximately 5.2 million Pacific Energy subordinated units for an aggregate purchase price of $700 million in cash. This purchase and sale will occur immediately prior to the consummation of our merger with Pacific Energy pursuant to our Agreement and Plan of Merger dated June 11, 2006. As a result of the merger, we will acquire the balance of Pacific Energy s equity through a unit-for-unit exchange in which each remaining unitholder of Pacific Energy will receive 0.77 newly issued PAA common units for each Pacific Energy common unit. The total value of the transaction is approximately $2.4 billion, including the assumption of debt and estimated transaction costs. The completion of the transaction remains subject to the approval of the unitholders of PAA and Pacific Energy. The unitholder meetings are scheduled for November 9, 2006. Assuming a favorable unitholder vote, we anticipate closing the transaction on November 15, 2006.

In November 2006, we acquired a 50% interest in Settoon Towing, LLC (Settoon Towing) for approximately $33 million. Settoon Towing owns and operates a fleet of 57 transport and storage barges as well as 30 transport tugs. Its core business is the gathering and transportation of crude oil and produced water from inland production facilities across the Gulf Coast. We are currently Settoon s largest customer with 22 tugs and 22 tank barges under a five-year chartering agreement, which commenced May 1, 2006.

Note 4 Inventory and Linefill

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars that is valued at the lower of cost or market, with cost determined using an average cost method. Linefill and minimum working inventory requirements are recorded at historical cost and consist of crude oil and LPG used to fill our pipelines such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities.

Linefill and minimum working inventory requirements in third party assets are included in Inventory (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of Inventory, at average cost, and into Inventory in Third Party Assets (a long-term asset), which is reflected as a separate line item within other assets on the consolidated balance sheet.

In the third quarter 2006, we recognized a $5.2 million non-cash charge primarily associated with the significant decline in oil prices and other product prices during the quarter and the related decline in the valuation of working inventory volumes. Approximately $3.4 million of the charge relates to crude oil linefill in pipelines owned by third parties and the remainder relates to LPG and other products inventory.

At September 30, 2006 and December 31, 2005, inventory and linefill consisted of :

	September 30, 2006			December 31, 2005		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory						
Crude oil	14,561	$ 1,009.0	$ 69.29	13,887	$ 755.7	$ 54.42
LPG	7,549	338.2	$ 44.80	3,649	149.0	$ 40.83
Parts and supplies	N/A	4.3	N/A	N/A	5.6	N/A
Inventory subtotal	22,110	1,351.5		17,536	910.3	
Inventory in third-party assets						
Crude oil	1,275	63.3	$ 49.65	1,248	58.6	$ 46.96
LPG	318	13.7	$ 43.08	318	12.9	$ 40.57
Inventory in third-party assets subtotal	1,593	77.0		1,566	71.5	
Pipeline linefill in owned assets						
Crude oil	6,578	203.0	$ 30.86	6,207	179.3	$ 28.89
LPG	31	1.1	$ 35.48	27	0.9	$ 33.33
Linefill subtotal	6,609	204.1		6,234	180.2	
Total	30,312	$ 1,632.6		25,336	$ 1,162.0	

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Note 5 Debt

In October 2006, we issued $400 million of 6.125% Senior Notes due 2017 and $600 million of 6.65% Senior Notes due 2037. The notes were sold at 99.56% and 99.17% of face value, respectively. Interest payments are due on January 15 and July 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for minor subsidiaries. We intend to use the proceeds to fund the cash portion of our proposed merger with Pacific Energy. Net proceeds in excess of the cash portion of the merger consideration will be used to repay amounts outstanding under our credit facilities and for general partnership purposes. If the merger with Pacific Energy is not closed on or prior to February 15, 2007 or the merger agreement relating to the Pacific Energy merger is terminated earlier, we will redeem the notes at 101% of the aggregate principal amount thereof plus accrued and unpaid interest to the date of redemption. In anticipation of the issuance of these notes, we had entered into $200 million notional principal amount of U.S. treasury locks to hedge the treasury rate portion of the interest rate on a portion of the notes. The treasury locks were entered into at an interest rate of 4.97%. See Note 9. Upon completion of the issuance of these notes, we terminated the $1.0 billion acquisition bridge facility that we entered into in July 2006 in contemplation of the Pacific Energy merger.

During May 2006, we completed the sale of $250 million aggregate principal amount of 6.70% Senior Notes due 2036. The notes were sold at 99.82% of face value. Interest payments are due on May 15 and November 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for minor subsidiaries. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

Below is a description of our debt as of:

	September 30, 2006	December 31, 2005
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 5.8% and 4.8% at September 30, 2006 and December 31, 2005, respectively	$ 778.8	$ 219.3
Working capital borrowings, bearing interest at a rate of 5.9% and 5.0% at September 30, 2006 and December 31, 2005, respectively [(1)]	212.0	155.4
Other	2.9	3.7
Total short-term debt	993.7	378.4
Long-term debt:		
4.75% senior notes due August 2009, net of unamortized discount of $0.5 million and $0.6 million at September 30, 2006 and December 31, 2005, respectively	174.5	174.4
7.75% senior notes due October 2012, net of unamortized discount of $0.2 million and $0.2 million at September 30, 2006 and December 31, 2005, respectively	199.8	199.8
5.63% senior notes due December 2013, net of unamortized discount of $0.5 million and $0.5 million at September 30, 2006 and December 31, 2005, respectively	249.5	249.5
5.25% senior notes due June 2015, net of unamortized discount of $0.6 million and $0.7 million at September 30, 2006 and December 31, 2005, respectively	149.4	149.3
5.88% senior notes due August 2016, net of unamortized discount of $0.9 million and $1.0 million at September 30, 2006 and December 31, 2005, respectively	174.1	174.0
6.70% senior notes due May 2036, net of unamortized discount of $0.5 million at September 30, 2006	249.5	

Senior notes, net of unamortized discount [2]	1,196.8	947.0
Long-term debt under credit facilities and other	3.6	4.7
Total long-term debt [1][2]	1,200.4	951.7
Total debt	$ 2,194.1	$ 1,330.1

(1) At September 30, 2006 and December 31, 2005, we have classified $212.0 million and $155.4 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) and Intercontinental exchange (ICE) margin deposits.

(2) At September 30, 2006, the aggregate fair value of our fixed rate senior notes is estimated to be

approximately
$1,223.6 million.

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In July 2006, we amended our senior unsecured revolving credit facility to increase the aggregate capacity from $1.0 billion to $1.6 billion and the sub-facility for Canadian borrowings from $400 million to $600 million. The amended facility can be expanded to $2.0 billion, subject to additional lender commitments, and has a final maturity of July 2011.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At September 30, 2006, we had outstanding letters of credit under our credit facility of approximately $93 million.

Note 6 Earnings Per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined by dividing net income available to limited partners by the weighted average number of limited partner units outstanding during the period. To calculate net income available to limited partners, income is first allocated to the general partner based on the amount of incentive distributions and the remainder is allocated between the limited partners and the general partner based on percentage ownership in the Partnership. EITF No. 03-06 (EITF 03-06), Participating Securities and the Two-Class Method under FASB Statement No. 128, addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. EITF 03-06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the period were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results, however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit.

The following sets forth the computation of basic and diluted earnings per limited partner unit.

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions, except per unit data)			
Numerator:				
Net income	$ 95.4	$ 69.0	$ 239.1	$ 164.1
Less: General partner s incentive distribution paid	(9.1)	(3.8)	(22.1)	(10.2)
Subtotal	86.3	65.2	217.0	153.9
General partner 2% ownership	(1.7)	(1.3)	(4.3)	(3.1)
Net income available to limited partners	84.6	63.9	212.7	150.8
EITF 03-06 additional general partner s distribution	(12.6)	(9.1)	(23.8)	(8.0)
Net income available to limited partners under EITF 03-06	$ 72.0	$ 54.8	$ 188.9	$ 142.8
Less: Limited partner 98% portion of cumulative effect of change in accounting principle			(6.2)	
Limited partner net income before cumulative effect of change in accounting principle	$ 72.0	$ 54.8	$ 182.7	$ 142.8
Denominator:				
Basic earnings per limited partner unit (weighted average number of limited partner units outstanding)	79.9	68.0	77.0	67.8
Effect of dilutive securities:				
Weighted average LTIP units outstanding (1)	0.9	1.4	0.8	1.1
Diluted earnings per limited partner unit (weighted average number of limited partner units outstanding)	80.8	69.4	77.8	68.9
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.90	$ 0.81	$ 2.37	$ 2.11
Cumulative effect of change in accounting principle per limited partner unit			0.08	
Basic net income per limited partner unit	$ 0.90	$ 0.81	$ 2.45	$ 2.11
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.89	$ 0.79	$ 2.35	$ 2.07
Cumulative effect of change in accounting principle per limited partner unit			0.08	
Diluted net income per limited partner unit	$ 0.89	$ 0.79	$ 2.43	$ 2.07

(1) Our LTIP awards that contemplate the issuance of common units described in Note 8 are considered dilutive securities unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in SFAS 128, Earnings per Share.

Note 7 Partners Capital and Distributions

Direct Placements of Common Units

We completed the following equity offerings of our common units during the nine months ended September 30, 2006 and 2005, respectively. See Note 10 Related Party Transactions.

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Period	Units	Gross Per Unit Price	Proceeds from Sale	GP Contribution	Costs	Net Proceeds
	(in millions, except unit amounts and per unit price)					
July/August 2006	3,720,930	$43.00	$160.0	$ 3.3	$(0.1)	$163.2
March/April 2006	3,504,672	$42.80	$150.0	$ 3.0	$(0.6)	$152.4
September/October 2005	5,854,000	$42.00	$246.0	$ 5.0	$(9.1)	$241.9
February 2005	575,000	$38.13	$ 21.9	$ 0.5	$(0.1)	$ 22.3

Distributions

The following table details the distributions we have declared and paid in the nine months ended September 30, 2006 and 2005 (in millions, except per unit amounts):

	Distributions Paid				
	Common Units	GP Incentive	2%	Total	Distribution per unit
August 14, 2006	$ 58.7	$ 9.1	$ 1.2	$ 69.0	$ 0.7250
May 15, 2006	54.6	7.4	1.1	63.1	$ 0.7075
February 14, 2006	50.7	5.6	1.0	57.3	$ 0.6875
2006 Total	$ 164.0	$ 22.1	$ 3.3	$ 189.4	

	Distributions Paid				
	Common Units	GP Incentive	2%	Total	Distribution per unit
August 12, 2005	$ 44.1	$ 3.8	$ 0.9	$ 48.8	$ 0.6500
May 13, 2005	43.3	3.5	0.9	47.7	$ 0.6375
February 14, 2005	41.2	2.9	0.9	45.0	$ 0.6125
2005 Total	$ 128.6	$ 10.2	$ 2.7	$ 141.5	

On October 24, 2006, we declared a cash distribution of $0.75 per unit on our outstanding common units. The distribution is payable on November 14, 2006, to unitholders of record on November 3, 2006, for the period July 1, 2006 through September 30, 2006. The total distribution to be paid is approximately $73 million, with approximately $61 million to be paid to our common unitholders and approximately $1 million and $11 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

Note 8 Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan and the 2005 Long-Term Incentive Plan, collectively referred to as Long-Term Incentive Plans (LTIP), for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the compensation committee or the board of directors of our general partner (each an Award). Under the LTIP, up to 4.4 million units may be issued in satisfaction of Awards. Certain Awards may also include distribution equivalent rights (DERs) at the discretion of the compensation committee or the board of directors of our general partner. Subject to applicable vesting criteria, a DER entitles the grantee to a cash payment equal to cash distributions paid on an outstanding common unit. Upon vesting, certain of the Awards may be settled in common units or equivalent cash value at the election of our general partner. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the LTIP.

As of September 30, 2006, there were approximately 2.2 million unvested phantom units outstanding with a weighted average grant-date fair value of approximately $32.22 per unit. In addition, approximately 1.6 million of these Awards include DERs. Approximately 1.5 million of the Awards vest over a six-year period from the grant date (with performance accelerators), while the remaining awards vest over time only if certain performance conditions are met and are forfeited after six years if the performance conditions are not met. The DERs vest over time (with performance accelerators) and terminate with the vesting or forfeiture of the related phantom units.

Our non-employee directors receive LTIP awards or cash equivalent awards as part of their compensation. These awards vest annually in 25% increments over a four-year period and have an automatic re-grant feature such that as they vest, an equivalent amount is granted. The three non-employee directors who serve on our audit committee each receive a grant of 10,000 units (vesting 2,500 units per year). The remaining three non-employee directors each receive 5,000 units (vesting 1,250 per year) or their cash equivalent.

We adopted Statement of Financial Accounting Standards No. 123(R) (revised 2004), Share Based Payment (SFAS 123(R)) on January 1, 2006 (See Note 13 for a discussion of recent accounting pronouncements). Under SFAS 123(R) the fair value of the Awards, which are subject to liability classification, is calculated based on the market price of our units at the balance sheet date adjusted for (i) the present value of any distributions that are probable of occurring on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is then expensed over the period the Awards are earned. In addition, we recognize compensation expense for DER payments in the period the payment is earned.

We recognized expense related to the LTIP of approximately $10 million and $7 million during the third quarters of 2006 and 2005, respectively, and $27 million and $17 million during the first nine months, of 2006 and 2005, respectively. Additionally, as of September 30, 2006, we have an accrued liability of approximately $43 million associated with the LTIP, of which $12 million is current.

As of September 30, 2006, the weighted average remaining contractual life of our outstanding Awards was approximately five years. Based on the September 30, 2006 fair value measurement, we expect to recognize an additional $54 million of expense over the life of our outstanding Awards related to the remaining unrecognized fair value. This estimate is based on the market price of our limited partner units at the end of the period and actual amounts may differ materially as a result of a change in market price. We estimate that the remaining fair value will be recognized in expense in the following years (in millions):

Year	**LTIP Fair Value Amortization**
2006 [1]	$ 7.3
2007	21.0
2008	14.1
2009	9.2
2010	2.6
Total	$ 54.2

[1] Includes LTIP fair value amortization for the remaining three months of 2006.

During October 2006, our general partner adopted the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the 2006 Plan) and subsequently granted approximately 0.8 million tracking units to non-executive employees. These awards contain performance related provisions that provide for vesting upon achieving distribution targets of $3.50, $3.75 and $4.00 per unit, subject to minimum service periods through 2010, but provides that 50% of the un-vested units will vest in 2012, subject to continued employment through such period. All remaining tracking units that have not vested by 2013 will terminate. Upon vesting, tracking units will be settled through cash payments based on the equivalent value of an equal number of common units. The aggregate grant date fair value of the tracking units awarded under the 2006 Plan is approximately $24.9 million.

Note 9 Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of the hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil, LPG and natural gas as well as with respect to expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, ICE and over-the-counter, including commodity swap and option contracts entered into with financial institutions and other energy companies.

The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to Accumulated Other Comprehensive Income (OCI) and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective (as defined in SFAS No. 133, Accounting For Derivative Instruments and Hedging Activities, as amended (SFAS 133)) in offsetting changes in cash flows of the hedged items are marked-to-market in revenues each period.

During the first nine months of 2006, our earnings include a net gain of approximately $80 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes:

a) A net mark-to-market gain of approximately $15 million (a $3 million loss in the first half of the year and a $18 million gain in the third quarter of 2006), which is primarily comprised of the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting,

b) A net gain of approximately $66 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during the first nine months of 2006, and

c) A net loss of approximately $1 million related to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated investments.

The following table summarizes the net assets and liabilities related to the fair value of our open derivative positions on our consolidated balance sheet as of September 30, 2006 and December 31, 2005, respectively (in millions):

	September 30, 2006	**December 31, 2005**
Other current assets	$ 165.9	$ 45.7
Other long-term assets	13.5	5.5
Other current liabilities	(40.7)	(72.5)
Other long-term liabilities and deferred credits	(22.3)	(6.5)
Net asset (liability)	$ 116.4	$ (27.8)

The net asset as of September 30, 2006 includes approximately $2 million of unrealized losses recognized in earnings and $118 million of unrealized gains on effective cash flow hedges that are deferred to OCI. The majority of the $2 million of unrealized losses that have been recognized in earnings relate to activities associated with our storage assets. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month to month.

We enter into derivative contracts,

including futures and options, that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. These derivatives do not qualify for hedge accounting because the contracts will not necessarily result in physical delivery.

At September 30, 2006, there was a total unrealized net gain of approximately $114 million deferred to OCI. This included approximately $118 million unrealized gains (referenced above), which predominantly related to unrealized gains on derivatives used to hedge physical inventory in storage that receive hedge accounting, and approximately $4 million deferred losses relating to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short futures positions that will result in gains when futures prices fall. These hedge gains are offset by a decrease in the physical inventory value and will be reclassed into earnings from OCI in the same period that the underlying physical inventory is sold. The total amount of deferred net gains recorded in OCI is expected to be reclassified to future earnings contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest.

During August 2006, we entered into two treasury locks with large creditworthy financial institutions in anticipation of a debt issuance in conjunction with our acquisition of Pacific Energy. A treasury lock is a financial derivative instrument that enables a company to lock in the U.S. Treasury Note rate. The U.S. Treasury Note rate was the benchmark interest rate for our anticipated debt issuance. The two treasury locks had a combined notional principal amount of $200 million and an effective interest rate of 4.97%. Both treasury locks mature in November 2006. The treasury locks are qualified cash flow hedges and the changes in fair value of the treasury locks are therefore deferred in OCI. At September 30, 2006, we had a net loss of approximately $6 million deferred in OCI related to the treasury locks. In October 2006, both treasury locks were terminated prior to maturity for an aggregate cash payment of $2 million in connection with the debt issuance in October 2006.

Of the total net gain deferred in OCI at September 30, 2006, a net gain of approximately $124 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the nine months ended September 30, 2006, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring.

Note 10 Related Party Transactions

Gas Hedges. PAA/Vulcan is developing a natural gas storage facility through its wholly owned subsidiary, Pine Prairie Energy Center, LLC (Pine Prairie). Proper functioning of the Pine Prairie storage caverns will require a minimum operating inventory contained in the caverns at all times (referred to as base gas). It is estimated that it will require approximately 7.3 billion cubic feet of base gas. During the first quarter of 2006, we arranged to provide the base gas for the storage facility to Pine Prairie at a price not to exceed $8.50 per million cubic feet. In conjunction with this arrangement, we executed hedges on the NYMEX for the relevant delivery periods of 2007, 2008 and 2009. We received a fee of approximately $1 million for our services to own and manage the hedge positions and to deliver the natural gas.

Equity Offerings. In March and April of 2006, we sold 3,504,672 common units, approximately 20% of which were sold to investment funds affiliated with Kayne Anderson Capital Advisors, L.P. (KACALP). The net proceeds were used to fund a portion of the Andrews acquisition, to reduce indebtedness and for general partnership purposes. In addition, in July and August 2006, we sold a total of 3,720,930 common units, approximately 12.5% and 18.7% of which were sold to investment funds affiliated with KACALP and Vulcan Capital, respectively. KAFU Holdings, L.P., which owns 20.3% of our general partner and has a representative on our board of directors, is managed by KACALP. Vulcan Capital, the investment arm of Paul G. Allen, and its subsidiaries own approximately 54% of our general partner interest and has a representative on our board of directors. The proceeds from the third quarter offering were used to fund acquisition costs, repay indebtedness under our credit facilities and for general partnership purposes.

On February 25, 2005, we issued 575,000 common units in a private placement to a subsidiary of Vulcan Energy Corporation (Valcan Energy). The sale price was $38.13 per unit, which represented a 2.8% discount to the closing price of the units on February 24, 2005. The sale resulted in net proceeds, including the general partner s proportionate capital contribution ($0.5 million) and net of expenses associated with the sale, of approximately $22.3 million.

Long-Term Incentive Plans. During the third quarter of 2006, we purchased 15,105 common units from our general partner for an average price of $46.03 per unit. The common units were used to satisfy our obligations with respect to awards that vested under our 1998 LTIP.

Administrative Services Agreement. On October 14, 2005, Plains All American GP LLC (GP LLC) and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the Services Agreement). Pursuant to the Services Agreement, GP LLC provides administrative services to Vulcan Energy for an annual fee plus reimbursement of certain expenses. The Services Agreement will be effective for a period of three years, at which time it will automatically renew for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Effective October 1, 2006, the annual fee was increased from $650,000 to $1 million.

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Note 11 Commitments and Contingencies

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency (EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4.5 million to $5.0 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act. We are cooperating in the investigation. Our assessment is that it is probable we will pay penalties related to the two releases. We have accrued the estimated loss contingency, which is included in the estimated aggregate costs set forth above. It is reasonably possible that the loss contingency may exceed our estimate with respect to penalties assessed by EPA; however, we have no indication from EPA or the Department of Justice of what penalties might be sought. As a result, we are unable to estimate the range of a reasonably possible loss contingency in excess of our accrual.

General. We, in the ordinary course of business, are a claimant and /or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Other. A pipeline, terminal or other facility may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. As a result of the significant wind damage claims filed following hurricanes Katrina, Rita and Wilma, the insurance industry has indicated that it will materially reduce the amount of coverage available for windstorm damages. Absent a material favorable change in the insurance markets, these trends are expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, no assurance can be given that we will be able to maintain adequate insurance in the future at rates we consider reasonable, or that we have established adequate reserves to the extent that such risks are not insured.

Long-term Contract. Effective May 1, 2006, we entered into a five-year agreement with Settoon Towing to charter 22 inland tugboats and 22 tank barges. Annual charter costs are projected to be approximately $22 million, subject to escalation limited by the increase in the Producer Price Index Finished Goods. Also, see Note 3.

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Note 12 Operating Segments

Our operations consist of two operating segments: (i) pipeline transportation operations (Pipeline) and (ii) gathering, marketing, terminalling and storage operations (GMT&S). Through our Pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain, and we operate certain terminalling and storage assets. The following tables reflect certain financial data for each segment for the periods indicated:

	Pipeline	GMT&S (in millions)	Total
Three Months Ended September 30, 2006			
Revenues:			
External Customers[(1)]	$ 241.3	$ 4,284.5	$ 4,525.8
Intersegment[(2)]	40.2	0.3	40.5
Total revenues of reportable segments	$ 281.5	$ 4,284.8	$ 4,566.3
Segment profit [(3)(4)(5)]	$ 52.2	$ 85.0	$ 137.2
SFAS 133 impact [(3)]	$	$ 17.9	$ 17.9
Maintenance capital	$ 5.3	$ 2.9	$ 8.2
Three Months Ended September 30, 2005			
Revenues:			
External Customers (includes buy/sell revenues of $52.2, $4,442.8, and $4,495.0 for Pipeline, GMT&S, and Total, respectively)	$ 268.8	$ 8,395.6	$ 8,664.4
Intersegment[(2)]	34.5	0.2	34.7
Total revenues of reportable segments	$ 303.3	$ 8,395.8	$ 8,699.1
Segment profit [(3)(4)(5)]	$ 45.7	$ 59.2	$ 104.9
SFAS 133 impact [(3)]	$	$ 6.3	$ 6.3
Maintenance capital	$ 2.9	$ 1.3	$ 4.2

	Pipeline	GMT&S (in millions)	Total
Nine Months Ended September 30, 2006			
Revenues:			
External Customers (includes buy/sell revenues of $45.3, $4,717.7, and $4,763.0 for Pipeline, GMT&S, and Total, respectively)	$ 725.6	$ 17,328.0	$ 18,053.6
Intersegment[(2)]	115.8	0.7	116.5

Total revenues of reportable segments	$ 841.4	$ 17,328.7	$ 18,170.1
Segment profit (3)(4)(5)	$ 143.3	$ 206.2	$ 349.5
SFAS 133 impact (3)	$	$ 14.8	$ 14.8
Maintenance capital	$ 11.5	$ 5.8	$ 17.3
Nine Months Ended September 30, 2005			
Revenues:			
External Customers (includes buy/sell revenues of $125.8, $11,630.0, and $11,755.8 for Pipeline, GMT&S, and Total, respectively)	$ 711.3	$ 21,752.3	$ 22,463.6
Intersegment(2)	99.8	0.7	100.5
Total revenues of reportable segments	$ 811.1	$ 21,753.0	$ 22,564.1
Segment profit (3)(4)(5)	$ 137.1	$ 129.2	$ 266.3
SFAS 133 impact (3)	$	$ (20.0)	$ (20.0)
Maintenance capital	$ 8.2	$ 4.0	$ 12.2

(1) The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statement of operations. See Note 13.

(2) Intersegment sales are conducted at arms length.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(4) GMT&S segment profit includes interest expense on contango purchases of \$14.5 million and \$7.2 million for the third quarter and \$35.9 million and \$16.4 million

for the nine months ended September 30, 2006 and 2005, respectively.

(5) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle (in millions):

	For the three months ended September 30,		For the nine months ended September 30,	
	2006	2005	2006	2005
Segment profit	$ 137.2	$ 104.9	$ 349.5	$ 266.3
Depreciation and amortization	(24.2)	(20.0)	(67.1)	(58.1)
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.3		2.2	
Interest expense	(19.2)	(15.6)	(52.5)	(44.4)
Interest income and other income (expense), net	0.3	(0.3)	0.7	0.3
Income before cumulative effect of change in accounting principle	$ 95.4	$ 69.0	$ 232.8	$ 164.1

Note 13 Recent Accounting Pronouncements

In December 2004, SFAS 123(R) was issued, which amends SFAS No. 123, Accounting for Stock-Based Compensation, and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. Following our general partner s adoption of Emerging Issues Task Force Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, we are part of the same consolidated group and thus SFAS 123 (R) will be applicable to our general partner s long-term incentive plan. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a cumulative effect of change in accounting principle of approximately $6 million. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair-value based liability as calculated under a SFAS 123(R) methodology. Our LTIPs are administered by our general partner. We are required to reimburse all costs incurred by our general partner through LTIP settlements. As a result, our LTIP awards are classified as liabilities under SFAS 123(R). Under the modified prospective transition method, we are not required to adjust our prior period financial statements for our LTIP awards.

In September 2005, the Emerging Issues Task Force (EITF) issued Issue No. 04-13 (EITF 04-13), Accounting for Purchases and Sales of Inventory with the Same Counterparty. The EITF concluded that inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 became effective in reporting periods beginning after March 15, 2006.

We adopted EITF 04-13 on April 1, 2006. The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statement of operations. In conformity with EITF 04-13, prior periods are not affected, although we have parenthetically disclosed prior period buy/sell transactions in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases on our income statement but does not impact our financial position, net income, or liquidity.

In September 2006, the SEC staff issued Staff Accounting Bulletin (SAB) Topic 1N, *Financial Statements - Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in Current Year Financial Statements* (SAB 108). SAB 108 addresses how the effects of prior-year uncorrected misstatements should be considered when quantifying misstatements in current-year financial statements. SAB 108 requires registrants to quantify misstatements using both the balance sheet and income statement approaches and to evaluate whether either approach results in quantifying an error that is material in light of relevant quantitative and qualitative factors. The provisions of SAB 108 will be effective for the fiscal years ending after November 15, 2006. Upon adoption, we do not expect SAB 108 to have a material impact on our financial position or results of operations.

Item 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Consolidated Financial Statements.

Highlights Third Quarter and First Nine Months of 2006

Net income for the third quarter of 2006 was approximately $95 million, or $0.89 per diluted limited partner unit, which is an increase of 38% and 13%, respectively, over net income of $69 million, or $0.79 per diluted limited partner unit for the third quarter of 2005. For the first nine months of 2006, net income was approximately $239 million, or $2.43 per diluted limited partner unit, representing increases of 46% and 17%, respectively, over net income of approximately $164 million, or $2.07 per limited partner unit, for the first nine months of 2005.

Earnings per limited partner unit (both basic and diluted) was reduced by $0.16 and $0.13 for the three months ended and $0.31 and $0.12 for the nine months ended September 30, 2006 and 2005, respectively, attributable to the application of Emerging Issues Task Force Issue No. 03-06, Participating Securities and the Two-Class Method under FASB Statement No. 128 . See Note 6 to our Consolidated Financial Statements.

Key items impacting the first nine months of 2006 include:

Balance Sheet and Capital Structure

- An issuance of $250 million senior notes due 2036 for net proceeds of approximately $249.5 million.
- The sale of 7.2 million limited partner units for net proceeds of approximately $316 million.
- The completion of six acquisitions for aggregate consideration of $567 million.
- An increase in 2006 planned capital expenditures for internal growth projects by $80 million to $310 million, of which approximately $214 million has been incurred.

Income Statement

- Favorable execution of our risk management strategies around our gathering, marketing, terminalling and storage assets in a pronounced contango market with a high level of overall crude oil volatility.
- Increased volumes and related tariff revenues on our pipeline systems.
- The inclusion in the third quarter and first nine months of 2006 of an aggregate charge of approximately $10 million and $27 million, respectively, related to our Long-Term Incentive Plans.
- An increase in costs and expenses primarily associated with our continued growth from internal growth projects and acquisitions.

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Acquisitions and Internal Growth Projects

The following table summarizes our capital expenditures incurred in the periods indicated (in millions):

	Nine Months Ended September 30,	
	2006	2005
Acquisition capital [1]	$ 566.6	$ 129.1
Investment in PAA/Vulcan Gas Storage, LLC	10.0	
Internal growth projects	213.6	106.9
Maintenance capital	17.3	12.2
	$ 807.5	$ 248.2

(1) The 2005 acquisition capital includes a deposit of approximately $12 million that was paid in 2004.

Acquisitions

We completed six transactions during the first nine months of 2006 for aggregate consideration of approximately $567 million. During the third quarter, we completed the acquisition of (i) a 64.35% interest in the CAM Pipeline system for a total purchase price of approximately $54 million and (ii) three refined products pipeline systems from Chevron Pipe Line Company for approximately $65 million. See Note 3 to our Consolidated Financial Statements.

In addition, in June 2006, we entered into a definitive agreement to purchase Pacific Energy for approximately $2.4 billion, including the assumption of debt and estimated transaction costs. The completion of the transaction remains subject to the approval of the unitholders of PAA and Pacific Energy. The unitholder meetings are scheduled for November 9, 2006. Assuming a favorable unitholder vote, we anticipate closing the transaction on November 15, 2006.

In November 2006, we acquired a 50% interest in Settoon Towing, LLC (Settoon Towing) for approximately $33 million. Settoon Towing owns and operates a fleet of 57 transport and storage barges as well as 30 transport tugs. Its core business is the gathering and transportation of crude oil and produced water from inland production facilities across the Gulf Coast. We are currently Settoon s largest customer with 22 tugs and 22 tank barges under a five year chartering agreement.

Internal Growth Projects

Capital expenditures for expansion projects are forecast to be approximately $310 million during calendar 2006 of which approximately $214 million was incurred in the first nine months. These projects include the construction and expansion of pipeline systems and crude oil and LPG storage facilities. Following are some of the more notable projects to be undertaken in 2006 and the estimated expenditures for the year (in millions):

Projects	2006
St. James, Louisiana storage facility Phase I	$ 72
St. James, Louisiana storage facility Phase II	12
Kerrobert tankage	31
East Texas/Louisiana tankage	17
Spraberry System expansion	15
Cushing Tankage Phase VI	14

High Prairie rail terminals	13
Midale/Regina truck terminal	13
Truck trailers	9
Wichita Falls tankage	8
Basin connection Oklahoma	8
Mobile/Ten Mile tankage and metering	6
Other Projects	92
Total	$ 310

St. James Terminal. On October 10, 2006, we announced we are proceeding with the Phase II development of the St. James Terminal facility. The initial construction of the St. James Terminal, referred to as the Phase I development, commenced in mid-2005 and is anticipated to become operational during the first quarter of 2007 at a total cost of approximately $93 million. Phase I consists of seven crude oil storage tanks with an aggregate shell capacity of approximately 3.5 million barrels along with the manifold and pumping system. Under the Phase II project, we will construct approximately 2.7 million barrels of additional tankage at the facility. The Phase II project will expand the total capacity of the facility to 6.2 million barrels and is expected to cost approximately $64 million. We estimate that the Phase II tankage will become operational during the first quarter of 2008.

Cushing Terminal Expansion. On September 19, 2006, we announced our Phase VI expansion of our Cushing Terminal facility. Under the Phase VI expansion, we will construct approximately 3.4 million barrels of additional tankage at our crude oil storage and terminalling facility in Cushing, Oklahoma. The Phase VI project will expand the total capacity of the facility to 10.8 million barrels and, including manifold modifications, is expected to cost approximately $48 million. We anticipate spending approximately $14 million of the $48 million in 2006 and the remainder in 2007. We estimate that the new tankage will become operational during the fourth quarter of 2007. The expansion is supported by multi-year lease agreements with customers.

Results of Operations

Analysis of Operating Segments

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative (G&A) expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our available cash (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period s earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which mitigate the actual decline in the useful life of our principal fixed assets. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining available cash, consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 12 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Pipeline Operations

As of September 30, 2006, we owned approximately 16,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada (of which approximately 14,000 miles are included in our Pipeline segment). Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third party leases of pipeline capacity (collectively referred to as tariff activities), as well as barrel exchanges and buy/sell arrangements (collectively referred to as pipeline margin activities). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable costs of operating the pipeline. Segment profit from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

The following table sets forth our operating results from our Pipeline segment for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2006	2005	2006	2005
	(in millions)		(in millions)	
Operating Results (1)				
Tariff activities	$ 106.9	$ 93.5	$ 299.1	$ 268.8
Pipeline margin activities (2)	174.6	209.8	542.3	542.3
Total pipeline operations revenues	281.5	303.3	841.4	811.1
Costs and Expenses				
Pipeline margin activities purchases (3)	(167.8)	(206.7)	(522.0)	(526.2)
Field operating costs (excluding LTIP charge)	(47.2)	(37.0)	(137.1)	(108.8)
LTIP charge operations	(0.4)	(0.3)	(1.0)	(0.7)
Segment G&A expenses (excluding LTIP charge) (4)	(9.8)	(10.2)	(27.1)	(29.6)
LTIP charge general and administrative (4)	(4.1)	(3.4)	(10.9)	(8.7)
Segment profit	$ 52.2	$ 45.7	$ 143.3	$ 137.1
Maintenance capital	$ 5.3	$ 2.9	$ 11.5	$ 8.2
Average Daily Volumes (thousands of barrels per day) (5)				
Tariff activities				
All American	50	51	49	51
Basin	324	290	323	283
BOA/CAM	168		57	
Capline	183	129	149	144
Cushing to Broome	69	79	73	62
North Dakota/Trenton	94	85	88	73
West Texas/New Mexico Area Systems (6)	416	428	445	422
Canada	249	250	247	255
Other	486	437	464	424
Total tariff activities	2,039	1,749	1,895	1,714
Pipeline margin activities	93	65	89	69
Total	2,132	1,814	1,984	1,783

(1) Revenues and purchases include intersegment amounts.

(2) Include revenues

associated with buy/sell arrangements of $52.2 million for the quarter ended September 30, 2005 and $45.3 million and $125.8 million for the nine months ended September 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 12,500 barrels per day for the quarter ended September 30, 2005 and 21,500 and 11,800 barrels per day for the nine months ended September 30, 2006 and 2005, respectively.

(3) Includes purchases associated with buy/sell arrangements of $47.1 million for the quarter ended September 30, 2005 and $45.7 million and $115.9 million for the nine months ended September 30,

2006 and 2005, respectively. Volumes associated with these arrangements were approximately 11,100 barrels per day for the quarter ended September 30, 2005 and 21,800 and 11,400 barrels per day for the nine months ended September 30, 2006 and 2005, respectively.

(4) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(5) Volumes associated with acquisitions

represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(6) The aggregate of multiple systems in the West Texas/New Mexico area.

Segment profit, our primary measure of segment performance, was driven by the following:

Increased volumes and related tariff revenues The increase in tariff revenues resulted from (i) higher volumes primarily from multi-year contracts on our Basin and Capline systems, (ii) increased volumes associated with the acquisitions, including the BOA/CAM/HIPS systems and the refined products systems, (iii) higher volumes on various other systems, and (iv) increased revenues from loss allowance oil of approximately $2 million and $8 million in the third quarter and first nine months of 2006, respectively. As is common in the industry, our crude oil tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. The loss allowance factor averages approximately 0.2%, by volume. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Gains or losses on sales of allowance oil barrels are also included in tariff revenues.

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- Increased volumes and higher crude oil prices during the third quarter and first nine months of 2006 as compared to the third quarter and first nine months of 2005 have resulted in increased revenues related to loss allowance oil. The NYMEX averages were $70.64 and $68.26 for the third quarter and first nine months of 2006, respectively, as compared to $63.26 and $55.51 for the third quarter and first nine months of 2005, respectively.

- Field operating costs and general and administrative expenses Field operating costs have increased for most categories of costs for the third quarter and first nine months of 2006 as we have continued to grow through acquisitions and expansion projects over the last year. The most significant cost increases have been related to (i) payroll and benefits and (ii) utilities. Utilities increased approximately $9 million for the first nine months of 2006 over the prior year period due to a variety of factors including (i) an increase in electricity consumption related to increased volumes partially offset by lower electricity market prices and (ii) a true-up of prior and current accruals following receipt of final billing information upon expiration of an existing term arrangement with a significant electricity provider. General and administrative expenses have decreased period over period primarily related to a decrease in the percentage of indirect costs allocated to the Pipeline segment in the 2006 period offset by increased LTIP expenses.

Total revenues for our Pipeline segment increased for the nine-month period ended September 30, 2006 as compared to the same period ended September 30, 2005 due to a combination of the following factors:

- An increase in tariff activities volumes due to (i) new multi-year contracts with shippers, (ii) the acquisition of the BOA/CAM/HIPS systems completed during the third quarter of 2006, as well as (iii) an increase in tariff activities revenues due to loss allowance oil (see discussion above);

- Pipeline margin activities revenues were constant for the nine-month period due to an increase in the average NYMEX price for crude oil sold and transported on our San Joaquin Valley (SJV) in 2006 as compared to 2005. Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales. Pipeline margin activities revenues were negatively impacted due to the adoption of EITF 04-13 which was equally offset with pipeline margin activities purchases and does not impact segment profit (see Note 13 to our Consolidated Financial Statements).

Total revenues for our Pipeline segment decreased for the three-month period ended September 30, 2006 as compared to the same period ended September 30, 2005 due to the following factors:

- Pipeline margin activities revenues were negatively impacted primarily due to the adoption of EITF 04-13 which was equally offset with pipeline margin activities purchases and does not impact segment profit (see Note 13 to our Consolidated Financial Statements); partially offset by

- An increase in tariff activities volumes due to (i) new multi-year contracts with shippers, (ii) the acquisition of the BOA/CAM/HIPS systems completed during third quarter 2006, as well as (iii) an increase in tariff activities revenues due to loss allowance oil (see discussion above).

Gathering, Marketing, Terminalling and Storage Operations

As of September 30, 2006, we owned approximately 39 million barrels of active above-ground crude oil terminalling and storage facilities, approximately 16 million barrels of which relate to our gathering, marketing, terminalling and storage segment (the remaining approximately 23 million barrels of tankage are associated with our pipeline transportation operations within our Pipeline segment). These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and is the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. In September 2006, we announced our Phase VI expansion of our Cushing terminal, in which we will construct approximately 3.4 million barrels of additional tankage and will expand the total capacity of the facility to 10.8 million barrels. In 2005, we began construction of a 3.5 million barrel crude oil terminal at the St. James crude oil interchange in Louisiana, which is also a major crude oil trading location. In October 2006, we announced we are proceeding with Phase II of the project and will construct approximately 2.7

million barrels of additional tankage at the facility. See *Internal Growth Projects* above for the current status of the St. James and Cushing terminal projects.

On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and thus the level of tankage that we allocate for our merchant activities (and therefore not available for lease to third parties) varies throughout crude oil market cycles. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery resulting from higher demand) provide an offset to this reduced cash flow. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. We believe that this combination of our terminalling and storage activities, gathering and marketing activities and our hedging activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities in an effort to maintain a base level of margin irrespective of whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions. We also believe that this balance enables us to protect against downside risk while at the same time providing us with upside opportunities in volatile market conditions.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, as well as isomerization, fractionation, marketing and transportation of natural gas liquids, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Total revenues for our GMT&S segment decreased for both the three and nine month periods ended September 30, 2006 as compared to the same periods ended September 30, 2005 due to a combination of the following factors:

- A decrease in our third quarter 2006 GMT&S revenues due to the adoption of EITF 04-13 which was equally offset with purchases and related costs and does not impact segment profit (see Note 13 to our Consolidated Financial Statements); offset by

- An increase in the average NYMEX price for crude oil in 2006 as compared to 2005 (as discussed above in Pipeline Operations). Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our GMT&S segment volumes, which are comprised of (i) lease gathered volumes, (ii) LPG sales and third party processing volumes and (iii) waterborne foreign crude imported. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business, our storage assets and our hedging activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period.

In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) GMT&S segment volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our GMT&S segment for the comparable periods indicated:

	Three months ended September 30,		Nine months ended September 30,	
	2006	2005	2006	2005
	(in millions, except per barrel amounts)		(in millions, except per barrel amounts)	
Operating Results[1]				
Revenues [2] [3]	$ 4,284.8	$ 8,395.8	$ 17,328.7	$ 21,753.0
Purchases and related costs [4] [5]	(4,136.7)	(8,292.7)	(16,945.9)	(21,496.8)
Field operating costs (excluding LTIP charge)	(43.4)	(30.4)	(120.7)	(89.0)
LTIP charge operations	(0.6)	(0.6)	(1.7)	(1.5)
Segment G&A expenses (excluding LTIP charge) [6]	(13.9)	(10.5)	(40.7)	(30.5)
LTIP charge general and administrative [6]	(5.2)	(2.4)	(13.5)	(6.0)
Segment profit [3]	$ 85.0	$ 59.2	$ 206.2	$ 129.2
SFAS 133 mark-to-market adjustment [3]	$ 17.9	$ 6.3	$ 14.8	$ (20.0)
Maintenance capital	$ 2.9	$ 1.3	$ 5.8	$ 4.0
Segment profit per barrel [7]	$ 1.18	$ 0.92	$ 1.00	$ 0.65

Average Daily Volumes (thousands of barrels per day) [8]				
Crude oil lease gathering	650	598	639	616
LPG sales and third party processing	55	41	60	50
Waterborne foreign crude imported	80	61	59	60
GMT&S Activities Total	785	700	758	726

(1) Revenues and purchases and related costs include intersegment amounts.

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(2) Includes revenues associated with buy/sell arrangements of $4,442.8 million for the quarter ended September 30, 2005 and $4,717.7 million and $11,630.0 million for the nine months ended September 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 810,000 barrels per day for the quarter ended September 30, 2005 and 898,000 and 826,000 barrels per day for the nine months ended September 30, 2006 and 2005, respectively.

(3) Amounts related to SFAS 133 are included in revenues and impact segment profit.

(4) Includes purchases associated with buy/sell arrangements of $4,425.4 million

for the quarter ended September 30, 2005 and $4,749.4 million and $11,426.0 million for the nine months ended September 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 831,000 barrels per day for the quarter ended September 30, 2005 and 905,000 and 823,000 barrels per day for the nine months ended September 30, 2006 and 2005, respectively.

(5) Purchases and related costs include interest expense on contango inventory purchases of approximately $14.5 million and $7.2 million for the quarters ended September 30, 2006 and 2005, respectively, and $35.9 million and $16.4 million for the nine months ended September 30, 2006 and 2005,

respectively.

(6) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each year.

(7) Calculated based on crude oil lease gathered, LPG sales and third party processing and waterborne foreign crude imported volumes.

(8) Volumes associated with acquistions represent total volumes for the number of days we actually owned the assets divided by the number of days in the period.

Segment profit for the third quarter and first nine months of 2006 exceeded the comparable 2005 period. The increase was primarily related to the following factors:

Acquisitions During the second quarter of 2006 we purchased Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids throughout the Western United States. In addition, during the second quarter we purchased crude oil gathering and transportation assets and related contracts in South Louisiana. See Note 3 to our Consolidated Financial Statements. These assets have partially contributed to the increase in crude oil lease gathered and LPG sales and third party processing volumes.

Favorable market conditions and execution of our risk management strategies During the first nine months of 2006 and 2005, the crude oil market has experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil has ranged from $57.55 to $78.40 during the first nine months of 2006. The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of both our gathering and marketing and our terminalling and storage assets. The market was in contango for most of the first nine months of 2006 and the time spread of prices averaged approximately $1.12 versus $0.80 for the same period in 2005, this increase in spreads was partially offset by an increase in the cost to carry the inventory that was not only impacted by the increase in LIBOR rates but also by the increase in NYMEX prices. Included in our GMT&S segment profit is contango and other hedged inventory related interest expense of approximately $14.5 and $35.9 million for the third quarter of 2006 and the first nine months of 2006, respectively, which is included in Purchases and related costs in the table above.

SFAS 133 mark-to-market The third quarter and first nine months of 2006 include SFAS 133 mark-to-market gains of $17.9 million and $14.8 million, respectively, compared to a gain of $6.3 million and a loss of $20.0 million for the comparable 2005 periods.

Inventory Adjustment In the third quarter 2006, we recognized a $5.2 million non-cash charge primarily associated with the significant decline in oil prices and other product prices during the quarter and the related decline in the valuation of working inventory volumes. Approximately $3.4 million of the charge relates to crude oil linefill in pipelines owned by third parties and the remainder relates to LPG and other products inventory.

Field operating costs and general and administrative expenses Partially offsetting these factors are increased field operating costs and general and administrative expenses of $19 million and $50 million for the three- and nine-month periods. Costs have increased primarily as a result of acquisitions in 2006. In addition, the third quarter of 2006 and the nine months ended September 30, 2006 include approximately $4 million and $12 million, respectively, of costs that are primarily related to third-party trucking transportation services, which were classified as Purchases and related costs in the 2005 period. The increase in general and administrative expenses is primarily the result of (i) an increase in the percentage of indirect costs allocated to the GMT&S segment in the 2006 period as the operations have grown and (ii) LTIP expenses.

Segment profit per barrel (calculated based on our GMT&S volumes included in the table above) was $1.18 for the quarter ended September 30, 2006, compared to $0.92 for the quarter ended September 30, 2005. Segment profit per barrel was $1.00 for the first nine months of 2006, compared to $0.65 for the first nine months of 2005. As discussed above, our current period results were strongly impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as have recently been experienced, and these operating results may not be indicative of sustainable performance.

Other Expenses

Depreciation and Amortization

Depreciation and amortization expense increased $4 million for the third quarter of 2006 and $9 million for the first nine months of 2006 compared to the comparable 2005 periods primarily as a result of continued expansion in our asset base from acquisitions and internal growth projects. Amortization of debt issue costs totaled approximately $2 million for the first nine months of 2006 and was relatively constant compared to the same period in 2005.

Interest Expense

Interest expense is primarily impacted by:

- our average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith; and
- market interest rates and our interest rate hedging activities on floating rate debt.

Interest expense increased approximately 23% and 18% in the third quarter and first nine months of 2006, respectively, as compared to the third quarter and first nine months of 2005, primarily due to higher average debt balances during 2006 partially offset by increased capitalized interest associated with certain capital projects under construction. The higher average debt balance in the first nine months of 2006 was primarily related to the addition of $250 million of senior notes. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our GMT&S segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $14.5 million and $35.9 million for the third quarter and first nine months of 2006, respectively. These costs were approximately $7.2 million and $16.4 million for the third quarter and first nine months of 2005, respectively.

Outlook

This section identifies certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions regarding potential acquisitions by us of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass midstream businesses outside of the scope of our historical operations. We are presently engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses, but we can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us. See Note 3 to our Consolidated Financial Statements.

In June 2006, Plains entered into a purchase agreement with LB Pacific, the owner of the general partner of Pacific Energy Partners, LP (Pacific Energy), pursuant to which Plains has agreed, subject to the terms and conditions set forth in the purchase agreement, to purchase from LB Pacific (i) all of the issued and outstanding limited partner interest in Pacific Energy GP, LP, a Delaware limited partnership and the general partner of Pacific Energy, (ii) the sole member interest in Pacific Energy Management LLC, a Delaware limited liability company and the general partner of Pacific Energy GP, LP, (iii) 5.2 million Pacific Energy common units and (iv) 5.2 million Pacific Energy subordinated units for an aggregate purchase price of $700 million in cash. This purchase and sale will occur immediately prior to the consummation of our merger with Pacific Energy pursuant to our Agreement and Plan of Merger dated June 11, 2006. As a result of the merger, we will acquire the balance of Pacific Energy s equity through a unit-for-unit exchange in which each remaining unitholder of Pacific Energy will receive 0.77 newly issued PAA common units for each Pacific Energy common unit. The total value of the transaction is approximately $2.4 billion, including the assumption of debt and estimated transaction costs. The completion of the transaction remains subject to the approval of the unitholders of PAA and Pacific Energy. The unitholder meetings are scheduled for November 9, 2006. Assuming a favorable unitholder vote, we anticipate closing the transaction on November 15, 2006.

Longer-Term Outlook. In our annual report on Form 10-K for the year ended December 31, 2005, we identified certain trends, factors and developments, many of which are beyond our control, that may affect our business in the future. We believe that the collective impact of these various trends, factors and developments has resulted in a crude oil market with high volatility that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings, which were evident in 2005 and into the first nine months of 2006. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At September 30, 2006, we had a working capital surplus of approximately $51 million and approximately $1.3 billion of availability under our committed revolving credit facility and approximately $21 million of availability under our uncommitted credit facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

In October 2006, we issued $400 million of 6.125% Senior Notes due 2017 and $600 million of 6.65% Senior Notes due 2037. Interest payments are due on January 15, and July 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for minor subsidiaries. We intend to use the proceeds to fund the cash portion of our proposed merger with Pacific Energy. Net proceeds in excess of the cash portion of the merger consideration will be used to repay amounts outstanding under our credit facilities and for general partnership purposes. Upon completion of the issuance of these notes, we terminated the $1.0 billion acquisition bridge facility that we entered into in July 2006 in contemplation of the Pacific Energy merger.

In July 2006, we amended our senior unsecured revolving credit facility to increase the aggregate capacity from $1.0 billion to $1.6 billion and the sub-facility for Canadian borrowings from $400 million to $600 million. The amended facility can be expanded to $2.0 billion, subject to additional lender commitments, and has a final maturity of July 2011.

Cash generated from operations

The crude oil market was in contango for most of the first nine months of 2006. Because we own crude oil storage capacity, during a contango market we can buy crude oil in the current month and simultaneously hedge the crude by selling it forward for delivery in a subsequent month. This activity can cause significant fluctuations in our cash flow from operating activities as described below.

The primary drivers of cash generated from our operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of pipeline linefill. The storage of crude oil in periods of a contango market can have a material negative impact on our cash flows from operating activities for the period in which we pay for and store the crude oil and a material positive impact in the subsequent period in which we receive proceeds from the sale of the crude oil. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Although to a lesser extent, the level of LPG inventory stored and held for resale at period end similarly affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it. Our accounts payable and accounts receivable generally vary proportionately because we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. However, when the market is in contango, our accounts receivable, accounts payable, inventory and short-term debt balances are all impacted, depending on the point of the cycle at any particular period end. As a result, we can have significant fluctuations in those working capital accounts, as we buy, store and sell crude oil.

Cash used for operating activities was $182 million and $450 million in the first nine months of 2006 and 2005, respectively, and reflects cash generated by our recurring operations (as indicated above in describing the primary drivers of cash generated from operations), offset by an increase in the amount of inventory that has been funded under our hedged inventory facility or as a working capital borrowing on our revolving credit facilty during 2006. A significant portion of the increased inventory has been purchased and stored due to contango market conditions and was paid for during the period via borrowings under our credit facilities or from cash on hand. As mentioned above, this activity has a negative impact in the period that we pay for and store the inventory. The fluctuations in our accounts receivable, inventory and accounts payable accounts during the period vary proportionally along with the fluctuations in our short-term debt balances.

Cash provided by equity and debt financing activities

We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $2 billion of debt or equity securities. At November 2, 2006, we had approximately $1.4 billion remaining under this registration statement.

Cash provided by financing activities was approximately $976 million and approximately $694 million for the nine months ended September 30, 2006 and 2005, respectively. Our financing activities primarily relate to funding (i) acquisitions, (ii) internal capital projects and (iii) short-term working capital and hedged inventory borrowings related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings under our credit facilities.

Equity Offerings. During the nine months ended September 30, 2006 and 2005, we completed equity offerings totaling $316 million and $236 million, respectively, including issuing a total of 3,720,930 common units pursuant to our existing shelf registration statement in a direct placement to a group of entities affiliated with institutional and private investors in the third quarter of 2006. See Note 7   Partners   Capital and Distributions   and Note 10   Related Party Transactions.

Senior Notes and Credit Facilities. During the nine months ended September 30, 2006 and 2005 we completed the sale of senior unsecured notes as summarized in the table below (in millions):

Year	Description	Face Value	Net Proceeds
		(in millions)	
2006	6.7% Senior Notes issued at 99.8% of face value	$250	$249.5
2005	5.25% Senior Notes issued at 99.5% of face value	$150	$149.3

During the nine months ended September 30, 2006 and 2005, we had working capital and short-term hedged inventory net borrowings of approximately $615 million and $601 million, respectively. These borrowings were used primarily for purchases of crude oil inventory that was stored. See Cash generated from operations. We also had $8 million of net long-term repayments under our revolving credit facility in the nine months ended September 30, 2006 and net repayments under our long-term revolving credit facilities of approximately $144 million in the nine months ended September 30, 2005.

Capital Expenditures and Distributions Paid to Unitholders and General Partners

We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. We finance these expenditures primarily with cash generated by operations and the financing activities discussed above. Our primary uses of cash are for our acquisition activities, capital expenditures for internal growth projects and distributions paid to our unitholders and general partner. See Acquisitions and Internal Growth Projects. The purchase price of the acquisitions includes cash paid, transaction costs and assumed liabilities and net working capital items. Because of the non-cash items included in the total purchase price of the acquisitions and the timing of certain cash payments, the net cash paid may differ significantly from the total purchase price of the acquisitions completed during the year.

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established for future requirements in the discretion of our general partner. Total cash distributions made during the first nine months of 2006 and 2005 were $189 million and $142 million, respectively. In addition, on October 24, 2006, we declared a cash distribution totaling $73 million to be paid on November 14, 2006. See Note 7 to our Consolidated Financial Statements.

Contingencies

See Note 11 to our Consolidated Financial Statements.

Commitments

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At September 30, 2006, we had outstanding letters of credit under our credit facility of approximately $93 million.

Other. Effective May 1, 2006, we entered into a five-year agreement with Settoon Towing to charter 22 inland tugboats and 22 tank barges. Annual charter costs are projected to be approximately $22 million, subject to escalation limited by the increase in the Producer Price Index Finished Goods.

Recent Accounting Pronouncements and Change in Accounting Principle

See Note 13 to our Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see Item 7 of our 2005 Annual Report on Form 10-K. Also, see Note 1 to our Consolidated Financial Statements.

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, inten forecast, and similar expressions and statements regarding our business strategy, plans and objectives of our management for future operations. However, the absence of these words 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:

- our failure to successfully integrate the respective business operations upon completion of the merger with Pacific Energy or our failure to successfully integrate any future acquisitions;

- the failure to realize the anticipated cost savings, synergies and other benefits of the proposed merger with Pacific Energy;

the success of our risk management activities;

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environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;

abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline system;

declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by us and third party shippers;

the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;

demand for natural gas or various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;

fluctuations in refinery capacity in areas supplied by our main lines;

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

our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;

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 and volatility (or lack thereof);

the impact of current and future laws, rulings and governmental regulations;

the effects of competition;

continued creditworthiness of, and performance by, our counterparties;

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;

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

weather interference with business operations or project construction;

general economic, market or business conditions;

risks related to the development and operation of natural gas storage facilities; and other factors and uncertainties inherent in the marketing, transportation, terminalling, gathering and storage of crude oil and liquefied petroleum gas.

Other factors, such as the Risks Related to Our Business discussed in Item 1A. Risk Factors of our most recent annual report on Form 10-K, the factors discussed in Item 1A of Part II of our quarterly report on Form 10-Q for the quarter ended June 30, 2006 and in this report, and factors that are unknown or

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unpredictable, could also have a material adverse effect on future results. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risks included in Item 7A in our 2005 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 9 to our Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

All of our open commodity price risk derivatives at September 30, 2006 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price increase are shown in the table below:

	Fair Value	Effect of 10% Price Increase
	(in millions)	
Crude oil:		
Futures contracts	$ 141.1	$ (37.7)
Swaps and options contracts	$ (35.1)	$ (28.0)
LPG:		
Futures contracts	$ (4.8)	$ 5.4
Swaps and options contracts	$ 20.8	$ 6.7
Total Fair Value	$ 122.0	

Interest Rate Risk

We use both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities. Therefore, from time to time we use interest rate swaps, collars and treasury locks to hedge interest obligations on specific debt issuances, including anticipated debt issuances. As of September 30, 2006, we had $200 million notional principal amount of U.S. treasury locks outstanding that we entered into in anticipation of a debt issuance in conjunction with our acquisition of Pacific Energy. The treasury locks are carried at fair value based on the U.S. Treasury 10-year yield in effect at September 30, 2006. The fair value of our outstanding interest rate derivatives at September 30, 2006 was a liability of $5.6 million and the change in fair value that would be expected from a 100 basis point rate decrease would increase the fair value of the liability by $17.1 million. In October 2006, both treasury locks were terminated for an aggregate cash payment of $2 million in conjunction with the underlying anticipated debt issuance. Also, see Note 8 to our Consolidated Financial Statements.

Item 4. CONTROLS AND PROCEDURES

We maintain written disclosure controls and procedures, which we refer to as our DCP. The purpose of our DCP is to provide reasonable assurance that information is (i) recorded, processed, summarized and reported in a manner that allows for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of September 30, 2006, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting (internal control) that occurred during the third quarter and that has materially affected, or is reasonably likely to materially affect, our internal control. In the process of documenting and testing our internal control in connection with compliance with Rule 13a-15(c) under the Securities Exchange Act of 1934, as amended (required by Section 404 of the Sarbanes-Oxley Act of 2002) we have made changes, and will continue to make changes, to refine and improve our internal control. However, as a result of their evaluation of changes in internal control, management identified no changes during the third quarter of 2006 that materially affected, or would be reasonably likely to materially affect, our internal control.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See Note 11 to our Consolidated Financial Statements.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2005 Annual Report on Form 10-K and Item 1A of our Quarterly Report on Form 10-Q for the quarter ended June 30, 2006. These risks and uncertainties are not the only ones facing us and there may be additional matters that we are unaware of or that we currently consider immaterial. All of these risks and uncertainties could adversely affect our business, financial condition and/or results of operations, as could the following:

Our tax treatment depends on our status as a partnership for U.S. and Canadian federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by individual states. If the IRS were to treat us as a corporation or if we become subject to a material amount of entity-level taxation for state tax purposes, it would substantially reduce the amount of cash available to pay our debt obligations.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay federal income tax on our income at the corporate tax rate, which is currently a maximum of 35%, and would likely pay state income tax at varying rates. Because a tax would be imposed upon us as a corporation, the cash available for distributions or to pay our debt obligations would be substantially reduced.

Current law may change so as to cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to entity-level taxation. In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. For example, we will be subject to a new entity level tax on the portion of our income that is generated in Texas beginning in our tax year ending in 2007. Specifically, the Texas margin tax will be imposed at a maximum effective rate of 0.7% of our gross income apportioned to Texas. Imposition of such a tax upon us as an entity by Texas or any other state will reduce the cash available for distributions or to pay our debt obligations.

In addition, in response to the perceived proliferation of income trusts in Canada, the Canadian government recently announced a proposed plan to impose entity-level taxes on certain types of flow-through entities. At this point, it is not clear whether the changes to the tax law, if implemented, would apply to our Canadian subsidiaries. Any entity-level taxation of our Canadian subsidiaries would reduce the cash available for distributions or to pay our debt obligations.

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Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Issuer Purchases of Equity Securities

Period	Total Number of Units Purchased	Average Price Paid per Unit	Total Number of Units Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or approximate dollar value) of Units that May Yet be Purchased Under the Plans or Programs
July 1, 2006 - July 31, 2006		n/a	n/a	n/a
August 1, 2006 - August 31, 2006	15,105(1)	$ 46.03	n/a	n/a
September 1, 2006 - September 30, 2006		n/a	n/a	n/a
TOTAL	15,105			

(1) In August 2006, we purchased 15,105 common units from our general partner for an average price of $46.03 per unit. The common units were used to satisfy our obligations with respect to awards that vested under our 1998 LTIP.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

2.1

	First Amendment to Agreement and Plan of Merger, dated July 19, 2006, by and among Pacific Energy Partners, L.P., Pacific Energy GP, LP, Pacific Energy Management LLC, Plains All American Pipeline, L.P., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed July 20, 2006)
3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001), as amended by Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of April 15, 2004 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.2	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.4	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001)
3.5	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001)
3.6	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005)

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3.7	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005)
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003)
4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)
4.6	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005)
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated as of May 12, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006)
4.8	Exchange and Registration Rights Agreement, dated as of May 12, 2006, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Citigroup Global Markets Inc., UBS Securities LLC, BNP Paribas Securities Corp., Banc of America Securities LLC, Fortis Securities LLC, J.P. Morgan Securities Inc., Piper Jaffray & Co., Wachovia Capital Markets, LLC, Amegy Bank National Association, Commerzbank Capital Markets Corp., DnB NOR Markets, Inc., HSBC Securities (USA) Inc. and Mitsubishi UFJ Securities International plc (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed May 12, 2006)

4.9	Seventh Supplemental Indenture, dated as of May 12, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains LPG Services GP LLC, Plains LPG Services, L.P. and Lone Star Trucking, LLC and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006)
4.10	Eighth Supplemental Indenture, dated as of August 25, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing International GP LLC, Plains Marketing International, L.P. and Plains LPG Marketing, L.P. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006)
4.11	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017), dated as of October 30, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006)
4.12	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037), dated as of October 30, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006)
4.13	Registration Rights Agreement dated as of July 26, 2006 among Plains All American Pipeline, L.P., Vulcan Capital Private Equity I LLC, Kayne Anderson MLP Investment Company and Kayne Anderson Energy Total Return Fund, Inc.
4.14	Exchange and Registration Rights Agreement dated as of October 30, 2006, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Plains Marketing International GP LLC, Plains LPG Marketing, L.P., Plains Marketing International, L.P., Citigroup Global Markets Inc., UBS Securities LLC, Banc of America Securities LLC, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, BNP Paribas Securities Corp., SunTrust Capital Markets, Inc., Fortis Securities LLC, Scotia Capital (USA) Inc., Comerica Securities, Inc., Commerzbank Capital Markets Corp., Daiwa Securities America Inc., DnB NOR Markets, Inc., HSBC Securities (USA) Inc., ING Financial Markets LLC, Mitsubishi UFJ Securities International plc, Piper Jaffray & Co., RBC Capital Markets Corporation, SG Americas Securities, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC relating to the 2017 Notes (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed October 30, 2006)
4.15	Exchange and Registration Rights Agreement dated as of October 30, 2006, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Plains Marketing International GP LLC, Plains LPG Marketing, L.P., Plains Marketing International, L.P., Citigroup Global Markets Inc., UBS Securities LLC, Banc of America Securities LLC, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, BNP Paribas Securities Corp., SunTrust Capital Markets, Inc., Fortis Securities LLC, Scotia Capital (USA) Inc., Comerica Securities, Inc., Commerzbank Capital

	Markets Corp., Daiwa Securities America Inc., DnB NOR Markets, Inc., HSBC Securities (USA) Inc., ING Financial Markets LLC, Mitsubishi UFJ Securities International plc, Piper Jaffray & Co., RBC Capital Markets Corporation, SG Americas Securities Inc. and Wells Fargo Securities, LLC relating to the 2037 Notes (incorporated by reference to Exhibit 4.4 to the Current Report on Form 8-K filed October 30, 2006)
10.1	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and JPMorgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC and Wachovia Capital Markets, LLC , as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006)
10.2	Interim 364-Day Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as Borrower; JPMorgan Chase Bank, N.A., as Administrative Agent; Bank of America, N.A. and Citibank, N.A., as Co-Syndication Agents; Wachovia Bank, National Association and UBS Securities LLC, as Co-Documentation Agents; the Lenders party thereto; and JPMorgan Securities Inc. and Citigroup Global Markets Inc., as Joint Bookrunners and Co-Lead Arrangers (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 4, 2006)
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a)
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a)

*32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
*32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350

Filed herewith.

* Furnished herewith.

Table of Contents

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 thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PLAINS AAP, L.P., its general partner

By: PLAINS ALL AMERICAN GP LLC, its general partner

Date: November 7, 2006

By: /s/ GREG L. ARMSTRONG

Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*

Date: November 7, 2006

By: /s/ PHIL KRAMER

Phil Kramer, *Executive Vice President and Chief Financial Officer (Principal Financial Officer)*

Index to Exhibits

2.1	First Amendment to Agreement and Plan of Merger, dated July 19, 2006, by and among Pacific Energy Partners, L.P., Pacific Energy GP, LP, Pacific Energy Management LLC, Plains All American Pipeline, L.P., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed July 20, 2006)
3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed August 27, 2001), as amended by Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of April 15, 2004 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.2	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.4	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001)
3.5	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001)
3.6	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005)
3.7	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005)
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003)

4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)

4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)
4.6	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005)
4.7	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated as of May 12, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006)
4.8	Exchange and Registration Rights Agreement, dated as of May 12, 2006, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Citigroup Global Markets Inc., UBS Securities LLC, BNP Paribas Securities Corp., Banc of America Securities LLC, Fortis Securities LLC, J.P. Morgan Securities Inc., Piper Jaffray & Co., Wachovia Capital Markets, LLC, Amegy Bank National Association, Commerzbank Capital Markets Corp., DnB NOR Markets, Inc., HSBC Securities (USA) Inc. and Mitsubishi UFJ Securities International plc (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed May 12, 2006)
4.9	Seventh Supplemental Indenture, dated as of May 12, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains LPG Services GP LLC, Plains LPG Services, L.P. and Lone Star Trucking, LLC and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006)
4.10	Eighth Supplemental Indenture, dated as of August 25, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing International GP LLC, Plains Marketing International, L.P. and Plains LPG Marketing, L.P. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006)
4.11	Ninth Supplemental Indenture (Series A and Series B 6.125% Sneior Notes due 2017), dated as of October 30, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006)
4.12	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037), dated as of October 30, 2006, to Indenture, dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp. and subsidiary guarantors signatory thereto and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006)

4.13	Registration Rights Agreement dated as of July 26, 2006 among Plains All American Pipeline, L.P., Vulcan Capital Private Equity I LLC, Kayne Anderson MLP Investment Company and Kayne Anderson Energy Total Return Fund, Inc.
4.14	Exchange and Registration Rights Agreement dated as of October 30, 2006, among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Basin Holdings GP LLC, Basin Pipeline Holdings, L.P., Rancho Holdings GP LLC, Rancho Pipeline Holdings, L.P., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC, Plains Marketing International GP LLC, Plains LPG Marketing, L.P., Plains Marketing International, L.P., Citigroup Global Markets Inc., UBS Securities LLC, Banc of America Securities LLC, J.P. Morgan Securities Inc., Wachovia Capital Markets, LLC, BNP Paribas Securities Corp., SunTrust Capital Markets, Inc., Fortis Securities LLC, Scotia Capital (USA) Inc., Comerica Securities, Inc., Commerzbank Capital Markets Corp., Daiwa Securities America Inc., DnB NOR Markets, Inc., HSBC Securities (USA) Inc., ING Financial Markets LLC, Mitsubishi UFJ Securities International plc, Piper Jaffray & Co., RBC Capital Markets Corporation, SG Americas Securities, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC relating to the 2017 Notes (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed October 30, 2006)
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