PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
November 07, 2007

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, 2007

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 5, 2007, there were outstanding 115,981,676 Common Units.

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Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except units)

	September 30, 2007	December 31, 2006
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 12.5	$ 11.3
Trade accounts receivable and other receivables, net	2,098.0	1,725.4
Inventory	964.9	1,290.0
Other current assets	109.2	130.9
Total current assets	3,184.6	3,157.6
PROPERTY AND EQUIPMENT	4,751.9	4,190.1
Accumulated depreciation	(479.2)	(348.1)
	4,272.7	3,842.0
OTHER ASSETS		
Pipeline linefill in owned assets	240.5	265.5
Inventory in third-party assets	63.0	75.7
Investment in unconsolidated entities	212.9	183.0
Goodwill	1,059.2	1,026.2
Other, net	154.3	164.9
Total assets	$ 9,187.2	$ 8,714.9
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,358.0	$ 1,846.6
Short-term debt	481.1	1,001.2
Other current liabilities	181.0	176.9
Total current liabilities	3,020.1	3,024.7
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	1.2	3.1

Senior notes, net of unamortized net discount of $2.0 and $1.8, respectively	2,623.0	2,623.2
Other long-term liabilities and deferred credits	119.7	87.1
Total long-term liabilities	2,743.9	2,713.4
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS CAPITAL		
Common unitholders (115,981,676 and 109,405,178 units outstanding at September 30, 2007 and December 31, 2006, respectively)	3,342.9	2,906.1
General partner	80.3	70.7
Total partners capital	3,423.2	2,976.8
Total liabilities and partners capital	$ 9,187.2	$ 8,714.9

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	**2006**	**2007**	**2006**
	(unaudited)		(unaudited)	
REVENUES				
Crude oil, refined products and LPG sales and related revenues (includes buy/sell transactions of $4,761.9 in the first three months of 2006)	$ 5,673.2	$ 4,449.4	$ 13,581.9	$ 17,843.8
Pipeline tariff activities revenues	93.2	71.4	272.7	198.4
Other revenues	32.6	4.7	91.7	10.4
Total revenues	5,799.0	4,525.5	13,946.3	18,052.6
COSTS AND EXPENSES				
Crude oil, refined products and LPG purchases and related costs (includes buy/sell transactions of $4,795.1 in the first three months of 2006)	5,455.2	4,261.5	12,884.4	17,343.3
Field operating costs	133.4	94.0	394.8	268.6
General and administrative expenses	33.4	33.0	127.9	92.2
Depreciation and amortization	42.9	24.2	134.9	67.1
Total costs and expenses	5,664.9	4,412.7	13,542.0	17,771.2
OPERATING INCOME	134.1	112.8	404.3	281.4
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	3.8	1.5	12.4	3.2
Interest expense (net of capitalized interest of $4.1 and $1.7 in the three months and $9.8 and $3.4 in the nine months ended September 30, 2007 and 2006, respectively)	(38.8)	(19.2)	(121.1)	(52.5)
Interest income and other income (expense), net	2.5	0.3	7.7	0.7
Income before tax	101.6	95.4	303.3	232.8
Current income tax expense	(0.4)		(1.3)	
Deferred income tax expense	(2.8)		(14.1)	
Income before cumulative effect of change in accounting principle	98.4	95.4	287.9	232.8
Cumulative effect of change in accounting principle				6.3

NET INCOME	$	98.4	$	95.4	$	287.9	$	239.1
NET INCOME-LIMITED PARTNERS	$	76.8	$	84.6	$	231.3	$	212.7
NET INCOME-GENERAL PARTNER	$	21.6	$	10.8	$	56.6	$	26.4
BASIC NET INCOME PER LIMITED PARTNER UNIT								
Income before cumulative effect of change in accounting principle	$	0.66	$	0.90	$	2.06	$	2.37
Cumulative effect of change in accounting principle								0.08
Net income	$	0.66	$	0.90	$	2.06	$	2.45
DILUTED NET INCOME PER LIMITED PARTNER UNIT								
Income before cumulative effect of change in accounting principle	$	0.66	$	0.89	$	2.05	$	2.35
Cumulative effect of change in accounting principle								0.08
Net income	$	0.66	$	0.89	$	2.05	$	2.43
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		116.0		79.9		112.1		77.0
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		116.8		80.8		113.0		77.8

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

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

	Nine Months Ended September 30, 2007	2006
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 287.9	$ 239.1
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	134.9	67.1
Cumulative effect of change in accounting principle		(6.3)
SFAS 133 mark-to-market adjustment	14.8	(14.8)
Gain on sale of investment assets	(3.9)	
Equity compensation charge	41.4	27.1
Income tax expense	15.4	
Noncash amortization of terminated interest rate hedging instruments	0.6	1.2
(Gain)/loss on foreign currency revaluation	(3.2)	2.1
Equity earnings in unconsolidated entities, net of distributions	(11.1)	(2.1)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(288.6)	(595.4)
Inventory	410.2	(414.6)
Accounts payable and other liabilities	368.3	512.4
Inventory in third-party assets	0.1	
Due to related parties	1.7	2.3
Net cash provided by (used in) operating activities	968.5	(181.9)
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 3)	(69.2)	(560.2)
Additions to property and equipment, net	(401.8)	(223.1)
Investment in unconsolidated entities	(9.3)	(10.0)
Cash paid for linefill in assets owned	(17.6)	(4.8)
Proceeds from sales of assets	13.7	3.8
Net cash used in investing activities	(484.2)	(794.3)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on long-term revolving credit facility		(7.7)
Net borrowings/(repayments) on working capital revolving credit facility	(125.6)	55.3
Net borrowings/(repayments) on short-term letters of credit and hedged inventory facility	(417.5)	559.5
Proceeds from issuance of senior notes		249.5
Net proceeds from the issuance of common units (Note 7)	382.5	315.6
Distributions paid to common unitholders (Note 7)	(272.7)	(164.0)
Distributions paid to general partner (Note 7)	(57.5)	(25.4)

Other financing activities	(0.5)	(6.6)
Net cash provided by (used in) financing activities	(491.3)	976.2
Effect of translation adjustment on cash	8.2	0.7
Net increase in cash and cash equivalents	1.2	0.7
Cash and cash equivalents, beginning of period	11.3	9.6
Cash and cash equivalents, end of period	$ 12.5	$ 10.3
Cash paid for interest, net of amounts capitalized	$ 146.1	$ 74.3
Cash paid for income taxes	$ 2.6	$

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

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

	Common Units		General Partner	Total Partners Capital
	Units	Amount	Amount	Amount
		(unaudited)		
Balance at December 31, 2006	109.4	$ 2,906.1	$ 70.7	$ 2,976.8
Net income		231.3	56.6	287.9
Distributions		(272.7)	(57.5)	(330.2)
Issuance of common units	6.3	374.8	7.7	382.5
Issuance of common units under Long-Term Incentive Plans (LTIP)	0.3	17.2	0.4	17.6
Capital contribution from General Partner Class B Units (non-cash)			0.6	0.6
Other comprehensive income		86.2	1.8	88.0
Balance at September 30, 2007	116.0	$ 3,342.9	$ 80.3	$ 3,423.2

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(unaudited)		(unaudited)	
Net income	$ 98.4	$ 95.4	$ 287.9	$ 239.1
Other comprehensive income	42.8	123.8	88.0	143.4
Comprehensive income	$ 141.2	$ 219.2	$ 375.9	$ 382.5

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

	Net Deferred Gain/(Loss) on Derivative	Currency Translation

	Instruments	Adjustments	Total
		(unaudited)	
Balance at December 31, 2006	$ (19.8)	$ 69.5	$ 49.7
Current Period Activity:			
Reclassification adjustments for settled contracts	(14.1)		(14.1)
Changes in fair value of outstanding hedge positions	(1.5)		(1.5)
Currency translation adjustment		103.6	103.6
Total period activity	(15.6)	103.6	88.0
Balance at September 30, 2007	$ (35.4)	$ 173.1	$ 137.7

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

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

Note 1 Organization and Accounting Policies

As used in this Form 10-Q and unless the context indicates otherwise, the terms Partnership, Plains, we, us, ou ours and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries. We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and 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. Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we are also engaged in the development and operation of natural gas storage facilities.

Our condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2006 Annual Report on Form 10-K. 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 three months and nine months ended September 30, 2007 should not be taken as indicative of the results to be expected for the full year.

The accompanying condensed consolidated financial statements of PAA include PAA and all of its wholly-owned subsidiaries. Investments in 50% or less owned entities over which we have significant influence but not control are accounted for by the equity method.

Note 2 Trade Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG and refined products. The majority of our accounts receivable relate to our marketing activities, which are generally high volume and low margin activities, in many cases involving exchanges of crude oil volumes. We determine the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or parental guarantees. At September 30, 2007 and December 31, 2006, we had received approximately $24 million and $28 million, respectively, of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At September 30, 2007 and December 31, 2006, substantially all of our net accounts receivable were less than 60 days past their scheduled invoice date. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts may vary significantly from estimated amounts.

Note 3 Acquisitions and Dispositions

During the first nine months of 2007, we acquired (i) a commercial refined products supply and marketing business (reflected in our marketing segment) for approximately $8 million in cash (including approximately $7 million of goodwill), (ii) a trucking business (reflected in our transportation segment) for approximately $9 million in cash (including approximately $4 million of goodwill) and (iii) the Bumstead LPG storage facility located near Phoenix, Arizona (reflected in our facilities segment) for approximately $52 million in cash (there was no goodwill associated with this acquisition). The Bumstead facility has a working capacity of approximately 3.2 million barrels of LPG. Also, during the third quarter of 2007, we signed an agreement to acquire the Tirzah LPG storage facility and other assets located near York County, South Carolina for approximately $54 million. The acquisition closed on October 2, 2007 and will be reflected in our facilities segment in the fourth quarter of 2007. The Tirzah facility has a working capacity of approximately 1.4 million barrels.

Certain adjustments related to the purchase price for the acquisition of Pacific Energy Partners, L. P. (Pacific) have been recorded in the first nine months of 2007, resulting in increased goodwill. The purchase price allocations related to the Pacific, Bumstead and Tirzah acquisitions are preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired.

In the first nine months of 2007, we incurred a net loss of approximately $8 million upon the disposition of certain inactive assets. This loss is included within Depreciation and Amortization in our Condensed Consolidated Statements of Operations.

Note 4 Inventory and Linefill

At September 30, 2007 and December 31, 2006, inventory and linefill consisted of:

	September 30, 2007			December 31, 2006		
	Barrels	Dollars	Dollar/ barrel (2)	Barrels	Dollars	Dollar/ barrel (2)
	(Barrels in thousands and dollars in millions)					
Inventory(1)						
Crude oil	7,527	$ 508.1	$ 67.50	18,331	$ 1,029.1	$ 56.14
LPG	8,673	441.0	$ 50.85	5,818	250.7	$ 43.09
Refined Products	94	7.2	$ 76.60	81	3.8	$ 46.91
Parts and supplies	N/A	8.6	N/A	N/A	6.4	N/A
Inventory subtotal	16,294	964.9		24,230	1,290.0	
Inventory in third-party assets						
Crude oil	1,173	58.3	$ 49.70	1,212	62.5	$ 51.57
LPG	100	4.7	$ 47.00	318	13.2	$ 41.51
Inventory in third-party assets subtotal	1,273	63.0		1,530	75.7	
Pipeline linefill in owned assets						
Crude oil	7,037	239.4	$ 34.02	7,831	264.4	$ 33.76
LPG	31	1.1	$ 35.48	31	1.1	$ 35.48
Pipeline linefill in owned assets subtotal	7,068	240.5		7,862	265.5	
Total	24,635	$ 1,268.4		33,622	$ 1,631.2	

(1) Includes the impact of inventory hedges on a portion of our volumes.

(2) The prices listed represent a weighted average price associated with various grades and qualities of crude oil, LPG and refined products and, accordingly, is not a comparable metric with published benchmarks for such products.

In the fourth quarter of 2007 we sold 250,000 barrels of pipeline linefill in owned assets for a gain of approximately $12 million. These volumes represent a change in the estimate of the amount of linefill required on certain of our assets. Linefill and minimum working inventory requirements in assets we own are recorded at historical cost.

Note 5 Debt

Below is a description of our debt as of September 30, 2007:

	September 30, 2007	December 31, 2006
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 5.9% and 5.8% at September 30, 2007 and December 31, 2006, respectively	$ 417.8	$ 835.3
Working capital borrowings, bearing interest at a rate of 6.0% and 5.9% at September 30, 2007 and December 31, 2006, respectively [1]	60.2	158.2
Other	3.1	7.7
Total short-term debt	481.1	1,001.2
Long-term debt:		
Senior notes, net of unamortized net discount [2]	2,623.0	2,623.2
Adjustment related to fair value hedge[3]	(1.4)	
Long-term debt under credit facilities and other	2.6	3.1
Total long-term debt [1][2]	2,624.2	2,626.3
Total debt	$ 3,105.3	$ 3,627.5

(1) At September 30, 2007 and December 31, 2006, we have classified $60 million and $158 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 inventory and New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) margin deposits.

(2) At September 30, 2007, the aggregate fair value of our fixed rate senior notes is estimated to be approximately $2,652 million. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

(3) Fair value hedge accounting was discontinued subsequent to June 30, 2007. The outstanding balance will be amortized over the remaining

life of the
underlying debt.

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In June 2007, the borrowing capacity under our senior secured hedged inventory facility was increased from $1.0 billion to $1.2 billion under the terms and conditions of such facility, as amended. The facility has a maturity date of November 16, 2007, and we anticipate extending the facility for an additional year, subject to lender approval.

On July 31, 2007, we amended our revolving credit facility to reset the maximum debt coverage ratio during an acquisition period from 5.25 to 1.0 to 5.5 to 1.0, and extend the maturity date from July 2011 to July 2012.

Letters of Credit

In connection with our crude oil marketing business and as is customary in our industry, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and our liabilities with respect to these purchase obligations are recorded in Accounts payable and accrued liabilities 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, 2007, approximately $51 million of letters of credit were outstanding under our credit facility (compared to approximately $186 million at December 31, 2006). Letter of credit fees are reflected within crude oil, refined products and LPG purchases and related costs on our Condensed Consolidated Statement of Operations.

Note 6 Earnings Per Limited Partner Unit

Subject to applicability of Emerging Issues Task Force Issue No. 03-06 (EITF 03-06), Participating Securities and the Two-Class Method under Financial Accounting Standards Board (FASB) Statement No. 128, as discussed below, Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated 98% to the limited partners and 2% to the general partner. Basic and diluted net income per limited partner unit is determined by dividing net income attributable to limited partners by the weighted average number of outstanding limited partner units during the period.

EITF 03-06 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 (or partnership distributions to unitholders). EITF 03-06 applies to any accounting period where our aggregate net income exceeds our aggregate distribution. In such periods, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed 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. This result occurs as a larger portion of our aggregate earnings is allocated (as if distributed) to our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. Earnings per limited partner unit (both basic and diluted) were reduced by $0.16 for the three months ended September 30, 2006 and $0.31 for the nine months ended September 30, 2006, attributable to the application of EITF 03-06. The application of EITF 03-06 had no impact for the three and nine months ended September 30, 2007.

The following table sets forth the computation of basic and diluted earnings per limited partner unit (in millions, except per unit data).

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	Three Months Ended September 30, 2007	2006	Nine Months Ended September 30, 2007	2006
Numerator:				
Net income	$ 98.4	$ 95.4	$ 287.9	$ 239.1
Less: General partner s incentive distribution paid	(20.0)	(9.1)	(51.9)	(22.1)
Subtotal	78.4	86.3	236.0	217.0
Less: General partner 2% ownership	(1.6)	(1.7)	(4.7)	(4.3)
Net income available to limited partners	76.8	84.6	231.3	212.7
Less: Pro Forma EITF 03-06 additional general partner s distribution		(12.6)		(23.8)
Net income available to limited partners under EITF 03-06	76.8	72.0	231.3	188.9
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	$ 76.8	$ 72.0	$ 231.3	$ 182.7
Denominator:				
Basic earnings per limited partner unit (weighted average number of limited partner units outstanding)	116.0	79.9	112.1	77.0
Effect of dilutive securities:				
LTIP units outstanding [(1)]	0.8	0.9	0.9	0.8
Diluted earnings per limited partner unit (weighted average number of limited partner units outstanding)	116.8	80.8	113.0	77.8
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.66	$ 0.90	$ 2.06	$ 2.37
Cumulative effect of change in accounting principle per limited partner unit				0.08
Basic net income per limited partner unit	$ 0.66	$ 0.90	$ 2.06	$ 2.45
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.66	$ 0.89	$ 2.05	$ 2.35
Cumulative effect of change in accounting principle per limited partner unit				0.08

Diluted net income per limited partner unit	$ 0.66	$ 0.89	$ 2.05	$ 2.43

(1) Our LTIP awards that contemplate the issuance of common units as 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 Statement of Financial Accounting Standards (SFAS) No. 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, 2007 and during the year ended December 31, 2006 (in millions, except unit and per unit amounts):

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Period	Units	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
June 2007	6,296,172	$59.56	$375.0	$ 7.7	$(0.2)	$382.5
December 2006	6,163,960	$48.67	$300.0	$ 6.1	$(0.5)	$305.6
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

LTIP Vesting

In May 2007, we issued 280,326 common units at a unit price of $61.47, for an approximate fair value of $17 million in connection with the settlement of vested LTIP awards. In addition, our general partner contributed $0.4 million in connection with the LTIP unit issuance.

Distributions

The following table details the distribution we declared in the fourth quarter of 2007 and the distributions we have declared and paid in the nine months ended September 30, 2007 and 2006 (in millions, except per unit amounts):

	Distributions				
	Common Unitholders	General Partner Incentive [2]	General Partner 2%	Total	Distribution per unit
Declared (to be paid)					
November 14, 2007 [1]	$ 97.4	$ 21.1	$ 2.0	120.5	$ 0.8400
Declared and paid					
August 14, 2007	$ 96.3	$ 19.9	$ 2.0	118.2	$ 0.8300
May 15, 2007	88.9	16.7	1.8	107.4	$ 0.8125
February 14, 2007	87.5	15.3	1.8	104.6	$ 0.8000
2007 total	$ 272.7	$ 51.9	$ 5.6	$ 330.2	
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	

(1) Declared on October 18, 2007 and payable on November 14, 2007 to unitholders of record on November 2, 2007, for the period July 1,

2007 through September 30, 2007.

(2) Upon closing of the Pacific acquisition in November 2006, our general partner agreed to reduce the amount of its incentive distributions as follows: (i) $5 million per quarter for the first four quarters beginning with the February 2007 distribution, (ii) $3.75 million per quarter for the following eight quarters, (iii) $2.5 million per quarter for the following four quarters, and (iv) $1.25 million per quarter for the final four quarters. The aggregate reduction in incentive distributions will be $65 million.

Note 8 Equity Compensation Plans

Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 Plan), the 2005 Long-Term Incentive Plan (the 2005 Plan) and the PPX Successor Long-Term Incentive Plan (the PPX Successor Plan) for employees and directors, as well as the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the 2006 Plan)

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for non-officer employees. The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the grant of an aggregate of 5.4 million common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to phantom units, which mature into the right to receive common units (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights (DERs). Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit prior to the vesting date of the underlying award. The 2006 Plan authorizes the grant of approximately 1.4 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a Common Unit at the time of vesting. Our general partner is entitled to reimbursement by us for any costs incurred in settling obligations under the plans for services provided to us.

Under SFAS 123(R) the fair value of LTIP awards, which are subject to liability classification, is calculated based on the closing market price of our units at each balance sheet date adjusted for (i) the present value of any distributions that are estimated to occur 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 recognized as compensation expense over the period the awards are earned. Our LTIP awards typically contain performance conditions based on attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions, we recognize LTIP compensation expense only if the achievement of the performance condition is considered probable and amortize that expense over the service period. When awards with performance conditions that were previously considered improbable of occurring become probable of occurring, we incur additional LTIP compensation expense necessary to adjust the life-to-date accrued liability associated with these awards. Our DER awards typically contain performance conditions based on attainment of certain annualized distribution levels and become earned upon the earlier of a certain date or the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. We recognize compensation expense for DER payments in the period the payment is earned.

At September 30, 2007 we have the following LTIP awards outstanding (units in millions):

LTIP Units Outstanding	**Distribution Amount**	**Unit Vesting Date**				
		2008	**2009**	**2010**	**2011**	**2012**
1.3 (1)	$3.20	0.1	0.6	0.6		
1.3 (2)	$3.50 - $4.00				0.7	0.6
1.0 (3)	$3.50 - $4.00			1.0		
3.6 (4) (5)		0.1	0.6	1.6	0.7	0.6

(1) Upon our February 2007 annualized distribution of $3.20, these LTIP awards satisfied all distribution requirements and will vest upon completion of the respective service period.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained, these awards will be forfeited. The awards are presented above assuming the distribution levels are attained.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00. Fifty percent of these awards will vest in 2012 regardless of whether the performance conditions are attained. The awards are presented above assuming the distribution levels are attained.

(4) Approximately 2.1 million of our 3.6 million outstanding LTIP awards also include DERs, of which 1.0 million are currently earned.

(5) LTIP units outstanding do not include Class B Restricted Units of our general partner (see below).

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Our LTIP activity is summarized in the following table (in millions, except weighted average grant date fair values per unit):

	Units	Weighted Average Grant Date Fair Value
Outstanding at January 1, 2007	3.0	$31.94
Granted	1.5	$44.18
Vested	(0.7)	$34.86
Cancelled or forfeited	(0.2)	$37.20
Outstanding at September 30, 2007	3.6	$36.26

Our accrued liability at September 30, 2007 related to all outstanding LTIP awards and DERs is approximately $47 million, which includes an accrual associated with our assessment that the distribution threshold of $3.50 is probable of occurring. We have not deemed a distribution of more than $3.50 to be probable.

Class B Units

On August 29, 2007, the Board of Directors of Plains All American GP LLC authorized the issuance of 200,000 Class B units of Plains AAP, L.P., our general partner. At September 30, 2007, approximately 85,500 Class B restricted units have been granted and the remaining units are reserved for future grants. The Class B restricted units are earned in 25% increments upon us achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50. When earned, the Class B units are entitled to participate in distributions paid to our general partner in excess of $11 million per quarter. Assuming all 200,000 Class B units were granted and earned, the maximum participation would be 8% of the general partner distribution in excess of $11.0 million each quarter. Although the entire economic burden of the Class B units, which are equity classified, are borne solely by the owners of our general partner and do not impact our cash or units outstanding, the intent of the Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and thus, results in a corresponding credit to the general partner s capital account in our Condensed Consolidated Financial Statements. The expense and capital contribution for the three and nine months ended September 30, 2007 were approximately $1 million.

Other Consolidated Information

We refer to our LTIP Plans and the Class B units collectively as our Equity compensation plans . The table below summarizes the expense recognized and the value of vestings (settled both in units and cash) related to our equity compensation plans (in millions):

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2007	**2006**	**2007**	**2006**
Equity compensation expense (1)	$1.0	$10.3	$41.4	$27.1
LTIP unit vestings	$0.5	$ 1.0	$17.7	$ 1.0
LTIP cash settled vestings	$0.3	$ 0.2	$16.1	$ 0.6
DER cash payments	$0.9	$ 0.9	$ 3.4	$ 2.1

(1) The Partnership s closing unit price decreased from $63.65 at

June 30, 2007 to $54.49 at September 30, 2007. As a result of the decrease in fair value associated with our outstanding LTIP awards, LTIP expense of approximately $8 million accrued in prior periods was reversed in the third quarter of 2007. Approximately $8 million of the charge for the first nine months of 2007 is associated with the Partnership s closing unit price increasing from $51.20 at December 31, 2006 to $54.49 at September 30, 2007.

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As of September 30, 2007, the weighted average remaining contractual life of our outstanding equity compensation awards (that are currently considered probable of vesting) was approximately 3.3 years based on expected vesting dates. Based on the September 30, 2007 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $76 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. This estimate is based on the closing market price of our limited partner units of $54.49 at September 30, 2007. Actual amounts may differ materially as a result of a change in market price and a change in probability assessment of future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity Compensation Plan Fair Value Amortization(1)
2007 (2)	$ 8.1
2008	29.1
2009	19.9
2010	12.5
2011	4.1
2012	2.2
Total	$ 75.9

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at September 30, 2007.

(2) Includes equity compensation plan fair value amortization for the remaining three months of 2007.

Note 9 Derivative Instruments and Hedging Activities

Summary of Financial Impact

The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, the ICE and over-the-counter, including commodity swap and option contracts entered into with financial institutions and other energy companies.

A summary of the earnings impact of all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings, is as follows (in millions, losses designated in parentheses):

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	For the Three Months Ended September 30, 2007			For the Three Months Ended September 30, 2006		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging	$(13.7)	$38.2	$24.5	$17.6	$70.3	$87.9
Controlled trading program		(0.4)	(0.4)			
Interest rate risk hedging	2.0	(0.2)	1.8		(0.4)	(0.4)
Currency exchange rate risk hedging	(0.9)	4.2	3.3	0.4		0.4
Total	$(12.6)	$41.8	$29.2	$18.0	$69.9	$87.9

	For the Nine Months Ended September 30, 2007			For the Nine Months Ended September 30, 2006		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging	$(19.4)	$120.4	$101.0	$14.3	$66.4	$80.7
Controlled trading program		0.5	0.5			
Interest rate risk hedging	1.7	(0.6)	1.1		(1.2)	(1.2)
Currency exchange rate risk hedging	2.9	4.0	6.9	0.6		0.6
Total	$(14.8)	$124.3	$109.5	$14.9	$65.2	$80.1

The breakdown of the net mark-to-market impact to earnings between derivatives that do not qualify for hedge accounting and the ineffective portion of cash flow hedges is as follows (in millions, losses designated in parentheses):

	For the Three Months ended September 30,		For the Nine Months ended September 30,	
	2007	2006	2007	2006
Derivatives that do not qualify for hedge accounting	$ (13.4)	$ 17.3	$ (14.2)	$ 13.7
Ineffective portion of cash flow hedges	0.8	0.7	(0.6)	1.2
Total	$ (12.6)	$ 18.0	$ (14.8)	$ 14.9

Derivatives that do not qualify for hedge accounting consist of (i) derivatives that are an effective element of our risk management strategy but are not consistently effective to qualify for hedge accounting pursuant to SFAS No. 133, Accounting For Derivative Instruments and Hedging Activities, as amended (SFAS 133), as they do not sufficiently correlate with the underlying transaction and (ii) certain transactions that have not been designated as hedges.

The following table summarizes the net assets and liabilities on our condensed consolidated balance sheet that are related to the fair value of our open derivative positions (in millions):

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	September 30, 2007	December 31, 2006
Other current assets	$ 37.4	$ 55.2
Other long-term assets	9.3	9.0
Other current liabilities	(94.2)	(77.3)
Long-term debt under credit facilities and other (fair value hedge adjustment) (1)	1.4	
Other long-term liabilities and deferred credits	(19.4)	(21.4)
Net asset (liability)	$ (65.5)	$ (34.5)

(1) Fair value hedge accounting was discounted subsequent to June 30, 2007. The outstanding balance will be amortized over the remaining life of the underlying debt.

The net liability related to the fair value of our open derivative positions consists of cumulative unrealized gains/losses recognized in earnings and cumulative unrealized gains/losses deferred to Accumulated Other Comprehensive Income (AOCI) as follows, by category (in millions, losses designated in parentheses):

	September 30, 2007			December 31, 2006		
	Net asset (liability)	Earnings	AOCI	Net asset (liability)	Earnings	AOCI
Commodity price-risk hedging	$(67.0)	$(38.2)	$(28.8)	$(32.5)	$(18.9)	$(13.6)
Controlled trading program						
Interest rate risk hedging	1.7	1.7				
Currency exchange rate risk hedging	(0.2)	0.8	(1.0)	(2.0)	(2.0)	
	$(65.5)	$(35.7)	$(29.8)	$(34.5)	$(20.9)	$(13.6)

In addition to the approximately $30 million of unrealized losses deferred to AOCI for open derivative positions, AOCI also includes a deferred loss of approximately $6 million that relates to terminated interest rate swaps that were cash settled in connection with the refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the terminated instruments.

The total amount of deferred net losses recorded in AOCI is expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. Of the total net loss deferred in AOCI at September 30, 2007, a net loss of approximately $29 million will be reclassified into earnings in the next twelve months. The remaining net loss will be reclassified at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2008 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 three and nine months ended September 30, 2007, no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring.

Note 10 Related Party Transactions

Crude Oil Purchases

Until August 12, 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. (Calumet). Until May 24, 2007, Calumet was owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. On May 24, 2007, Calumet was sold and ceased to be related to Vulcan. In the period from January 1, 2007 through May 24, 2007, we purchased crude oil from Calumet for approximately $17.2 million. In the third quarter and the first nine months of 2006, we purchased crude oil from Calumet for approximately $15.7 million and $38.3 million, respectively.

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). 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 a price below $8.50 for the relevant delivery periods of 2008, 2009 and 2010. We recorded deferred revenue for receipt of a one-time fee of approximately $1 million for our services to own and manage the hedge positions and to deliver the natural gas.

Note 11 Income Taxes

Our U.S. and Canadian subsidiaries are not taxable entities in the U.S. and are not subject to U.S. federal or state income taxes because the tax effect of operations is passed through to our unitholders. However, certain of our Canadian subsidiaries are taxable entities in Canada and are subject to Canadian federal and provincial income taxes. Our provision for income taxes for the three and nine months ended September 30, 2007 reflects these Canadian federal and provincial taxes in addition to tax obligations under the Texas Margin Tax described below.

In June 2007, Canadian legislation was passed that imposes Canadian tax on *Specified Flow-Through Investments* (SIFT). The legislation includes a safe harbor provision which grandfathers existing entities and delays the effective date of such legislation until 2011 subject to companies not exceeding the normal growth guidelines as defined in the legislation. Although limited guidance is currently available, we believe that it is more likely than not that our Canadian partnership will be considered a SIFT under the legislation and thus would be subject to the tax. We are currently within the normal growth guidelines as defined in the legislation, which delays the effective date for us until 2011. In conjunction with the passage of this legislation, we have recognized a net deferred income tax expense of approximately $11 million during the nine months ended September 30, 2007. This amount represents the estimated tax effect of temporary differences that exist at September 30, 2007 and are expected to reverse after the date that this legislation is effective for us based on the 31.5% tax rate that is expected to be in effect when these temporary differences reverse. Substantially all of this amount is related to differences between book basis and tax basis depreciation on applicable property and equipment. If and when facts and circumstances change, we will reassess our position and record adjustments as necessary.

We adopted the provisions of FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes (FIN 48), an interpretation of SFAS No. 109 Accounting for Income Taxes , on January 1, 2007. The adoption of FIN 48 had no material impact on our financial statements. We recognize interest and penalties related to uncertain tax positions in income tax expense. At September 30, 2007, we have no material assets, liabilities or accrued interest associated with uncertain tax positions.

We file income tax returns in Canadian federal and various provincial jurisdictions. Generally, we are no longer subject to Canadian federal and provincial income tax examinations for years before 2004.

Note 12 Commitments and Contingencies

Litigation

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, the U.S. Environmental Protection Agency (the 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 \$3.0 million to \$3.5 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 (the DOJ) 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 the DOJ; however, we have no indication from EPA or the DOJ 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.

On November 15, 2006, we completed the acquisition of Pacific. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

The People of the State of California v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately \$26 million, substantially all of which had been incurred as of September 30, 2007. We expect to incur the remaining costs before the end of 2007. We anticipate that the majority of such costs will be covered under a pre-existing PPS pollution liability insurance policy.

In March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four-count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine, if any, that can be assessed is estimated to be approximately \$1.1 million in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of recovered crude oil, and the State of California has the discretion to further reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the strict liability offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately \$150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of the natural resource damages amount. We believe that certain of the alleged violations are without merit and intend to defend against them, and that mitigating factors should apply.

The EPA has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately \$3.7 million. We believe that several mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and intend to pursue discussions with the EPA regarding such mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be assessed by the EPA cannot be ascertained. Discussions with the DOJ to resolve this matter have commenced.

Pacific Atlantic Terminals. In connection with the Pacific merger, we acquired Pacific Atlantic Terminals LLC (PAT), which is now one of our subsidiaries. PAT owns crude oil and refined products terminals in northern California and in the Philadelphia metropolitan area. In the process of integrating PAT s assets into our operations, we identified certain aspects of the operations at the California terminals that appeared to be out of compliance with specifications under the relevant air quality permit. We conducted a prompt review of the circumstances and self-reported the apparent historical occurrences of non-compliance to the Bay Area Air Quality Management District. We are cooperating with the District s review of these matters. Although we are currently unable to determine the outcome of the foregoing, at this time, we do not believe it will have a material impact on our financial condition, results of operations or cash flows.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in the imposition of fines and penalties. For example, we have been informed by the EPA that terminals owned by Rocky Mountain Pipeline Systems LLC, one of the subsidiaries acquired in the Pacific merger, are purportedly out of compliance with certain regulatory documentation requirements.

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 or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental. We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our standards and procedures, remove selected assets from service and spend capital to upgrade the assets. In the near-term post-acquisition period, however, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link Energy LLC in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas. See also Pipeline Releases above.

At September 30, 2007, our reserve for environmental liabilities totaled approximately $37 million, of which approximately $16 million is classified as short-term and approximately $21 million is classified as long-term. At September 30, 2007, we have recorded receivables totaling approximately $8 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements. Although we believe our reserve is adequate, costs incurred in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

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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. Absent a material favorable change in the environmental insurance markets, this trend is 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 environmental 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, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

Regulation

A substantial portion of PAA s petroleum pipelines and storage tanks in the United States are subject to regulation by the U.S. Department of Transportation s (DOT) Pipeline and Hazardous Materials Safety Administration with respect to the design, installation, testing, construction, operation, replacement and management of pipeline and tank facilities. Comparable regulation exists in some states in which PAA conducts intrastate common carrier or private pipeline operations. Regulation in Canada is under the National Energy Board and provincial agencies. In addition, PAA must permit access to and copying of records, and must make certain reports available and provide information as required by the Secretary of Transportation. U.S. Federal pipeline safety rules also require pipeline operators to develop and maintain a written qualification program for individuals performing covered tasks on pipeline facilities.

In 2001, the DOT adopted the initial pipeline integrity management rule, which required operators of jurisdictional pipelines transporting hazardous liquids to develop and follow an integrity management program that provides for continual assessment of the integrity of all pipeline segments that could affect so-called high consequence areas, including high population areas, areas that are sources of drinking water, ecological resource areas that are unusually sensitive to environmental damage from a pipeline release, and commercially navigable waterways. In December 2003, the DOT issued a final rule requiring natural gas pipeline operators to develop similar integrity management programs for gas transmission pipelines located in high consequence areas. Segments of PAA s pipelines transporting hazardous liquids and/or natural gas in high consequence areas are subject to these DOT rules and therefore obligate PAA to evaluate pipeline conditions by means of periodic internal inspection, pressure testing, or other equally effective assessment means, and to correct identified anomalies. If, as a result of PAA s evaluation process, PAA determines that there is a need to provide further protection to high consequence areas, then PAA will be required to implement additional spill prevention, mitigation and risk control measures for its pipelines. The DOT rules also require PAA to evaluate and, as necessary, improve its management and analysis processes for integrating available integrity related data relating to its pipeline segments and to remediate potential problems found as a result of the required assessment and evaluation process. Costs associated with this program were approximately $3 million in the third quarter of 2007 and $11 million for the first nine months of 2007. Based on currently available information, PAA s preliminary estimate for the remainder 2007 is approximately $5 million. The relative increase in program cost over the last few years is primarily attributable to pipeline segments acquired in recent years (including the Pacific and Link assets), which are subject to the rules. Certain of these costs are recurring in nature and thus will impact future periods. PAA will continue to refine its estimates as information from its assessments is collected. Although PAA believes that its pipeline operations are in substantial compliance with currently applicable regulatory requirements, PAA cannot predict the potential costs associated with additional, future regulation.

Note 13 Operating Segments

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In the fourth quarter of 2006, we revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. Prior period disclosures have been revised to reflect our change in segments. Our operations are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing.

Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including, but not limited to segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity in earnings of unconsolidated entities 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. 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. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which act to partially offset the age-related decline in the value of our principal fixed assets. These maintenance investments 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.

The following tables reflect certain financial data for each segment for the periods indicated (in millions):

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Three Months Ended September 30, 2007	Transportation	Facilities	Marketing	Total
Revenues:				
External Customers (1)	$ 106.7	$ 30.8	$ 5,661.5	$ 5,799.0
Intersegment (2)	91.4	23.2	6.5	121.1
Total revenues of reportable segments	$ 198.1	$ 54.0	$ 5,668.0	$ 5,920.1
Equity earnings in unconsolidated entities	$ 1.5	$ 2.3	$	$ 3.8
Segment profit (1)(3)(4)	$ 91.8	$ 28.7	$ 60.3	$ 180.8
SFAS 133 impact (1)	$	$	$ (14.6)	$ (14.6)
Maintenance capital investment	$ 9.2	$ 0.2	$ 0.5	$ 9.9

Three Months Ended September 30, 2006	Transportation	Facilities	Marketing	Total
Revenues:				
External Customers (1)	$ 86.7	$ 8.7	$ 4,430.1	$ 4,525.5
Intersegment (2)	48.2	12.6	0.3	61.1
Total revenues of reportable segments	$ 134.9	$ 21.3	$ 4,430.4	$ 4,586.6
Equity earnings in unconsolidated entities	$ 0.2	$ 1.3	$	$ 1.5
Segment profit (1)(3)(4)	$ 53.3	$ 9.0	$ 76.2	$ 138.5
SFAS 133 impact (1)	$	$	$ 17.9	$ 17.9
Maintenance capital investment	$ 5.3	$ 1.9	$ 1.0	$ 8.2

Nine Months Ended September 30, 2007	Transportation	Facilities	Marketing	Total
Revenues:				
External Customers (1)	$ 317.2	$ 87.3	$ 13,541.8	$ 13,946.3
Intersegment (2)	253.3	66.0	23.3	342.6
Total revenues of reportable segments	$ 570.5	$ 153.3	$ 13,565.1	$ 14,288.9
Equity earnings in unconsolidated entities	$ 3.6	$ 8.8	$	$ 12.4
Segment profit (1)(3)(4)	$ 244.6	$ 79.5	$ 227.5	$ 551.6
SFAS 133 impact (1)	$	$	$ (16.5)	$ (16.5)

Maintenance capital investment	$	21.6	$	6.4	$	3.6	$	31.6

	Transportation		Facilities		Marketing		Total	
Nine Months Ended September 30, 2006								
Revenues:								
External Customers (includes buy/sell revenues of $0, $0, and $4,761.9, respectively) (1) (5)	$	244.0	$	21.2	$	17,787.4	$	18,052.6
Intersegment (2) (5)		139.7		33.4		0.7		173.8
Total revenues of reportable segments	$	383.7	$	54.6	$	17,788.1	$	18,226.4
Equity earnings in unconsolidated entities	$	1.0	$	2.2	$		$	3.2
Segment profit (1)(3)(4)	$	144.8	$	19.6	$	187.3	$	351.7
SFAS 133 impact (1)	$		$		$	14.8	$	14.8
Maintenance capital investment	$	11.7	$	3.4	$	2.2	$	17.3

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

(2) Intersegment sales are intended to reflect arm s-length transactions.

(3) Marketing segment profit includes interest expense on contango purchases of approximately $13 million and $15 million for the three months ended September 30, 2007 and 2006, respectively, and approximately $38 million and $36 million for the nine months ended September 30, 2007 and 2006, respectively.

(4) 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, 2007	For the three months ended September 30, 2006	For the nine months ended September 30, 2007	For the nine months ended September 30, 2006
Segment profit	$ 180.8	$ 138.5	$ 551.6	$ 351.7
Depreciation and amortization	(42.9)	(24.2)	(134.9)	(67.1)
Interest expense	(38.8)	(19.2)	(121.1)	(52.5)
Interest income and other income (expense), net	2.5	0.3	7.7	0.7
Income tax expense	(3.2)		(15.4)	
Income before cumulative effect of change in accounting principle	$ 98.4	$ 95.4	$ 287.9	$ 232.8

(5) The adoption of EITF 04-13 in 2006 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 statements of operations.

Note 14 Recent Accounting Pronouncements

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of FAS 115 (SFAS 159). SFAS 159 allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value in situations in which they are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. The provisions of SFAS 159 will be effective for fiscal years beginning after November 15, 2007. We are evaluating the impact of adoption of SFAS 159 but do not currently expect the adoption to have a material impact on our financial position, results of operations or cash flows.

In December 2006, the FASB issued FASB Staff Position EITF 00-19-2, Accounting for Registration Payment Arrangements (the FSP). The FSP specifies that the contingent obligation to make future payments under a registration payment arrangement should be separately recognized and measured in accordance with FASB Statement No. 5 Accounting for Contingencies. The FSP was effective immediately for registration payment arrangements and the financial instruments subject to those arrangements entered into or modified subsequent to December 21, 2006. For registration payment arrangements and for the financial instruments subject to those arrangements that were entered into prior to December 21, 2006, the FSP is effective for fiscal years beginning after December 15, 2006. At September 30, 2007, we did not have any material contingent obligations under registration payment arrangements.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability in such measurement. The provisions of SFAS 157 will be effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. The impact, if any, from the adoption of SFAS 157 in 2008 will depend on our assets and liabilities that are required to be measured at fair value at that time.

In September 2006, the FASB issued FASB Staff Position AUG AIR-1, Accounting for Planned Major Maintenance Activities (FSP AUG AIR-1). FSP AUG AIR-1 prohibits the use of the accrue-in-advance method of accounting for planned major maintenance activities. FSP AUG AIR-1 is effective for the first fiscal year beginning after December 15, 2006. We expense major maintenance activities as incurred. The adoption of FSP AUG AIR-1 did not have any impact on our financial position, results of operations or cash flows.

In June 2006, the EITF issued Issue No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should Be Presented in the Income Statement (That Is, Gross versus Net Presentation) (EITF 06-3). EITF 06-3 is effective for all periods beginning after December 15, 2006 and its scope includes any tax that is assessed by a governmental authority that is both imposed on and concurrent with a specific revenue-producing transaction between a seller and a customer. The EITF stated that it is an entity s accounting policy decision whether to present the taxes on a gross basis (within revenues and costs) or on a net basis (excluded from revenues) but that the accounting policy should be disclosed. If presented on a gross basis, an entity is required to report the amount of such taxes for each period for which an income statement is presented, if those amounts are significant. Our accounting policy is to present such taxes on a net basis.

Note 15 Supplemental Condensed Consolidating Financial Information

Some, but not all, of our 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of our Senior Notes. Given that certain, but not all, subsidiaries are guarantors of our Senior Notes, we are required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, the parent company is referred to as Plains All American. See Note 12 of Part IV of our 2006 Annual Report on Form 10-K for detail of which subsidiaries are classified as Guarantor Subsidiaries and which subsidiaries are classified as Non-Guarantor Subsidiaries.

The following supplemental condensed consolidating financial information reflects Plains All American s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and Plains All American s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, Plains All American s investments in its subsidiaries and the Guarantor Subsidiaries investments in their subsidiaries are accounted for under the equity method of accounting.

Condensed Consolidating Balance Sheet
September 30, 2007

	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
ASSETS					
Total current assets	$ 2,343.7	$ 2,935.7	$ (4.5)	$ (2,090.3)	$ 3,184.6
Property plant and equipment, net		3,647.9	624.8		4,272.7
Other assets:					
Investment in unconsolidated entities	3,722.0	848.8		(4,357.9)	212.9
Other assets	21.3	1,180.9	314.8		1,517.0
Total assets	$ 6,087.0	$ 8,613.3	$ 935.1	$ (6,448.2)	$ 9,187.2

LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 42.2	$ 4,919.7	$ 148.5	$ (2,090.3)	$ 3,020.1
Other liabilities:					
Long-term debt	2,621.5	2.7			2,624.2
Other long-term liabilities and deferred credits	0.1	118.6	1.0		119.7
Total liabilities	2,663.8	5,041.0	149.5	(2,090.3)	5,764.0
Partners Capital	3,423.2	3,572.3	785.6	(4,357.9)	3,423.2
Total liabilities and partners capital	$ 6,087.0	$ 8,613.3	$ 935.1	$ (6,448.2)	$ 9,187.2

Condensed Consolidating Balance Sheet
December 31, 2006

	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (in millions)	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,573.8	$ 3,048.7	$ 97.6	$ (2,562.5)	$ 3,157.6
Property plant and equipment, net		3,226.9	615.1		3,842.0
Other assets:					
Investment in unconsolidated entities	3,037.7	731.3		(3,586.0)	183.0
Other assets	23.0	1,197.9	311.4		1,532.3
Total assets	$ 5,634.5	$ 8,204.8	$ 1,024.1	$ (6,148.5)	$ 8,714.9
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 34.2	$ 5,355.9	$ 14.1	$ (2,379.5)	$ 3,024.7
Other liabilities:					
Long-term debt	2,623.2	(273.3)	276.4		2,626.3
Other long-term liabilities and deferred credits	0.3	84.5	2.3		87.1
Total liabilities	2,657.7	5,167.1	292.8	(2,379.5)	5,738.1
Partners Capital	2,976.8	3,037.7	731.3	(3,769.0)	2,976.8
Total liabilities and partners capital	$ 5,634.5	$ 8,204.8	$ 1,024.1	$ (6,148.5)	$ 8,714.9

Condensed Consolidating Statement of Operations
Three Months Ended September 30, 2007

	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (in millions)	Eliminations	Consolidated
Net operating revenues [1]	$	$ 312.2	$ 31.6	$	$ 343.8
Field operating costs		(124.5)	(8.9)		(133.4)
General and administrative expenses		(31.2)	(2.2)		(33.4)
Depreciation and amortization	(0.7)	(37.2)	(5.0)		(42.9)

Operating income	(0.7)	119.3	15.5		134.1
Equity earnings in unconsolidated entities	135.1	17.0		(148.3)	3.8
Interest expense	(38.5)	(0.3)			(38.8)
Interest and other income (expense), net	2.5				2.5
Income tax expense		(3.2)			(3.2)
Net income (loss)	$ 98.4	$ 132.8	$ 15.5	$ (148.3)	$ 98.4

(1) Net operating revenues are calculated as Total revenues less Crude oil, refined products and LPG purchases and related costs.

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	Condensed Consolidating Statement of Operations Nine Months Ended September 30, 2007				
	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
			(in millions)		
Net operating revenues [1]	$	$ 970.7	$ 91.2	$	$ 1,061.9
Field operating costs		(367.3)	(27.5)		(394.8)
General and administrative expenses	(0.1)	(126.7)	(1.1)		(127.9)
Depreciation and amortization	(2.0)	(117.8)	(15.1)		(134.9)
Operating income	(2.1)	358.9	47.5		404.3
Equity earnings in unconsolidated entities	407.7	51.1		(446.4)	12.4
Interest expense	(120.7)	(0.4)			(121.1)
Interest and other income (expense), net	3.0	4.7			7.7
Income tax expense		(15.4)			(15.4)
Net income (loss)	$ 287.9	$ 398.9	$ 47.5	$ (446.4)	$ 287.9

(1) Net operating revenues are calculated as Total revenues less Crude oil, refined products and LPG purchases and related costs.

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	Condensed Consolidating Statements of Cash Flows Nine Months Ended September 30, 2007				
	Plains All American	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries (in millions)	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 287.9	$ 398.9	$ 47.5	$ (446.4)	$ 287.9
Adjustments to reconcile to cash flows from operating activities:					
Depreciation, amortization and other	2.0	117.8	15.1		134.9
SFAS 133 mark-to-market adjustment	(1.7)	16.5			14.8
Gain on sale of investment assets		(3.9)			(3.9)
Equity compensation charge		41.4			41.4
Income tax expense		15.4			15.4
Noncash amortization of terminated interest rate hedging instruments	0.6				0.6
Gain on foreign currency revaluation		(3.2)			(3.2)
Equity earnings in unconsolidated entities, net of distributions	(407.7)	(49.8)		446.4	(11.1)
Net change in assets and liabilities, net of acquisitions	76.3	453.8	(38.4)		491.7
Net cash provided by (used in) operating activities	(42.6)	986.9	24.2		968.5
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisition		(69.2)			(69.2)
Additions to property and equipment		(377.6)	(24.2)		(401.8)
Investment in unconsolidated entities, net	(9.3)				(9.3)
Cash paid for linefill in assets owned		(17.6)			(17.6)
Proceeds from sales of assets		13.7			13.7
Net cash used in investing activities	(9.3)	(450.7)	(24.2)		(484.2)

CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on working capital revolving credit facility		(125.6)			(125.6)
Net repayments on short-term letter of credit and hedged inventory facility		(417.5)			(417.5)
Net proceeds from the issuance of common units	382.5				382.5
Distributions paid to unitholders and general partner	(330.2)				(330.2)
Other financing activities		(0.5)			(0.5)
Net cash provided by (used in) financing activities	52.3	(543.6)			(491.3)
Effect of translation adjustment on cash		8.2			8.2
Net increase (decrease) in cash and cash equivalents	0.4	0.8			1.2
Cash and cash equivalents, beginning of period	2.3	9.0			11.3
Cash and cash equivalents, end of period	$ 2.7	$ 9.8	$	$	$ 12.5

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For the three months and nine months ended September 30, 2006, the Non-Guarantor Subsidiaries were considered minor, as defined by Regulation S-X rule 3-10(h)(6). As a result, supplemental condensed consolidating financial information is not presented for those periods.

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 our results of operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2006 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the Notes to the Condensed Consolidated Financial Statements.

Highlights Third Quarter and First Nine Months of 2007

	For the three months ended September 30, 2007	2006	Change (%)	For the nine months ended September 30, 2007	2006	Change (%)
Net income (in millions)	$98.4	$95.4	3%	$287.9	$239.1	20%
Earnings per basic limited partner unit (1)	$0.66	$0.90	(27)%	$ 2.06	$ 2.45	(16)%
Earnings per diluted limited partner unit (1)	$0.66	$0.89	(26)%	$ 2.05	$ 2.43	(16)%

(1) See Note 6 to our Condensed Consolidated Financial Statements for a discussion of the impact of Emerging Issues Task Force (EITF) Issue No. 03-06, Participating Securities and the Two-Class Method under Financial Accounting Standards Board (FASB) Statement No. 128.

Key items impacting the first nine months of 2007 include:

Income Statement

- Contributions from three acquisitions in 2007 and the November 2006 acquisition of Pacific Energy Partners L.P. (Pacific) as well as eight additional acquisitions throughout 2006.

- Favorable execution of our risk management strategies around our marketing assets in a market with a high level of crude oil volatility. See Outlook.

Increased equity compensation plan expense of $41 million (compared to approximately $27 million for the first nine months of 2006), primarily resulting from additional Long - Term Incentive Plan (LTIP) grants.

Deferred tax expense of approximately $11 million pertaining to recently enacted Canadian tax legislation.

An increase in costs and expenses associated with internal growth projects and acquisitions.

A net loss of approximately $8 million upon disposition of certain inactive assets.

A $9 million increase in equity earnings in unconsolidated entities.

A $4 million gain on the sale of a portion of our stock ownership in the NYMEX.

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A loss of approximately $15 million related to the mark-to-market impact for derivative instruments (compared to a gain of approximately $15 million for the first nine months of 2006).

Balance Sheet and Capital Structure

The completion of three acquisitions for aggregate consideration of approximately $69 million.

The sale of 6.3 million limited partner units in 2007 for net proceeds of approximately $383 million. Our earnings per unit data for the nine months ended September 30, 2007 compared to the corresponding period of 2006 is also impacted by the sale of 6.2 million limited partner units in December 2006 (for net proceeds of approximately $306 million) and the November 2006 issuance of 22.2 million limited partner units (valued at approximately $1 billion) in exchange for Pacific limited partner units as part of the Pacific acquisition.

Capital expenditures for internal growth projects of $392 million for the first nine months of 2007, which represent approximately 73% of the 2007 planned expansion capital expenditures.

Acquisitions and Internal Growth Projects

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

	Nine Months Ended September 30,	
	2007	**2006**
Acquisition capital	$ 69.2	$ 566.6
Investment in unconsolidated entities	9.3	10.0
Internal growth projects	392.3	213.6
Maintenance capital investment	31.6	17.3
	$ 502.4	$ 807.5

Acquisitions

During the first nine months of 2007, we acquired (i) a commercial refined products supply and marketing business (reflected in our marketing segment) for approximately $8 million in cash (including approximately $7 million of goodwill), (ii) a trucking business (reflected in our transportation segment) for approximately $9 million in cash (including approximately $4 million of goodwill) and (iii) the Bumstead LPG storage facility located near Phoenix, Arizona (reflected in our facilities segment) for approximately $52 million in cash (there was no goodwill associated with this acquisition). The Bumstead facility has a working capacity of approximately 3.2 million barrels of LPG. Also, during the third quarter of 2007, we signed an agreement to acquire the Tirzah LPG storage facility and other assets located near York County, South Carolina for approximately $54 million. The acquisition closed on October 2, 2007 and will be reflected in our facilities segment. The Tirzah facility has a working capacity of approximately 1.4 million barrels.

Certain adjustments related to the purchase price for the Pacific acquisition have been recorded in the first nine months of 2007, resulting in increased goodwill. The purchase price allocations related to the Pacific, Bumstead and Tirzah acquisitions are preliminary and subject to change, pending finalization of the valuation of the assets and liabilities acquired.

Internal Growth Projects

We forecast approximately $540 million in capital expenditures for expansion projects during calendar year 2007, of which approximately $392 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 undertaken in 2007 and the estimated expenditures for the year (in millions):

Projects	**2007**
St. James, Louisiana Storage Facility (1)	$ 80.0

Cheyenne Pipeline	68.0

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Projects	**2007**
Salt Lake City Expansion (1)	55.0
Cushing Tankage Phase VI (1)	34.0
Patoka Tankage (1)	32.0
Martinez Terminal (1)	25.0
Fort Laramie Tank Expansion (1)	21.0
High Prairie Rail Terminal	12.0
Paulsboro Expansion (1)	8.0
Elk City to Calumet (1)	12.0
Pier 400 (2)	7.0
Kerrobert Tankage	9.0
Other Projects (3)	177.0
Total	$ 540.0

(1) These projects will continue into 2008 and we expect to incur an additional $100 million to $110 million in 2008 with respect to such projects (primarily related to the Patoka Tankage and Paulsboro Expansion projects). We expect to have additional projects in 2008, but have not finalized our 2008 capital plan.

(2) This project requires approval of a number of city and state regulatory agencies in

California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(3) Primarily pipeline connections, upgrades and truck stations as well as new tank construction and refurbishing.

We do not expect the majority of these projects to contribute significantly to net income or cash flow from operations in 2007, but expect them to have a more significant impact in late 2008.

We forecast approximately $48 million in capital expenditures for maintenance projects during calendar year 2007, of which approximately $32 million was incurred in the first nine months.

Results of Operations

	For the three months ended September 30,		For the nine months ended September 30,	
	2007	2006	2007	2006
	(in millions)		(in millions)	
Transportation segment profit	$ 91.8	$ 53.3	$ 244.6	$ 144.8
Facilities segment profit	28.7	9.0	79.5	19.6
Marketing segment profit	60.3	76.2	227.5	187.3
Total segment profit	180.8	138.5	551.6	351.7
Depreciation and amortization	(42.9)	(24.2)	(134.9)	(67.1)
Interest expense	(38.8)	(19.2)	(121.1)	(52.5)
Interest income and other income	2.5	0.3	7.7	0.7
Income tax expense	(3.2)		(15.4)	
Income before cumulative effect of change in accounting principle	98.4	95.4	287.9	232.8
Cumulative effect of change in accounting principle				6.3
Net income	$ 98.4	$ 95.4	$ 287.9	$ 239.1

Analysis of Operating Segments

In order to evaluate the performance of our segments, management focuses on the following metrics: (i) segment profit, (ii) segment volumes, (iii) segment profit per barrel calculated on these volumes and (iv) maintenance capital investment. See Note 13 to our Condensed Consolidated Financial Statements for further discussion on how we evaluate segment performance.

Transportation

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

	Three Months Ended September 30,		Change		Nine Months Ended September 30,		Change	
	2007	2006	$	%	2007	2006	$	%
Operating Results (in millions, except per barrel amounts) [1]								
Revenues								
Tariff revenue	$ 168.7	$ 111.7	$ 57.0	51%	$ 485.8	$ 314.2	$ 171.6	55%
Third-party trucking	29.4	23.2	6.2	27%	84.7	69.5	15.2	22%
Total transportation revenues	198.1	134.9	63.2	47%	570.5	383.7	186.8	49%
Costs and Expenses								
Third-party trucking costs	(19.7)	(17.8)	(1.9)	11%	(57.7)	(54.6)	(3.1)	6%
Field operating costs (excluding equity compensation (charge)/credit)	(73.8)	(48.2)	(25.6)	53%	(213.4)	(141.9)	(71.5)	50%
Equity compensation (charge)/credit operations [2]	0.1	(1.1)	1.2	(109)%	(4.5)	(2.8)	(1.7)	61%
Segment G&A expenses (excluding equity compensation charge) [3]	(13.9)	(10.8)	(3.1)	29%	(37.7)	(30.2)	(7.5)	25%
Equity compensation charge general and administrative [2]	(0.5)	(3.9)	3.4	(87)%	(16.2)	(10.4)	(5.8)	56%
Equity earnings in unconsolidated entities	1.5	0.2	1.3	650%	3.6	1.0	2.6	260%
Segment profit	$ 91.8	$ 53.3	$ 38.5	72%	$ 244.6	$ 144.8	$ 99.8	69%
Maintenance capital investment	$ 9.2	$ 5.3	$ 3.9	74%	$ 21.6	$ 11.7	$ 9.9	85%
Segment profit per barrel	$ 0.36	$ 0.26	$ 0.10	38%	$ 0.32	$ 0.25	$ 0.07	28%
Average Daily Volumes (thousands of barrels per day) [4]								
Tariff activities:								
All American	46	50	(4)	(8)%	48	49	(1)	(2)%
Basin	397	324	73	23%	382	323	59	18%
Capline	230	183	47	26%	232	149	83	56%
Line 63 / 2000	171	N/A	171	N/A	177	N/A	177	N/A
Salt Lake City	59	N/A	59	N/A	62	N/A	62	N/A
North Dakota/Trenton	93	94	(1)	(1)%	95	88	7	8%
West Texas/New Mexico area systems	409	416	(7)	(2)%	391	445	(54)	(12)%
Manito	72	73	(1)	(1)%	74	70	4	6%
Refined products	110	15	95	633%	110	5	105	2100%

Other	1,118	977	141	14%	1,125	855	270	32%
Tariff activities total	2,705	2,132	573	27%	2,696	1,984	712	36%
Trucking volumes	104	103	1	1%	107	111	(4)	(4)%
Transportation Activities Total	2,809	2,235	574	26%	2,803	2,095	708	34%

(1) Revenues and purchases include intersegment amounts.

(2) Compensation expense related to our equity compensation plans.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(4) Volumes associated with acquisitions

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

Segment profit and segment profit per barrel, our primary measures of segment performance, were impacted by the following:

Increased volumes and related tariff revenues The increase in volumes and tariff revenues is attributable to a combination of the following factors:

Pipeline systems acquired or brought into service during 2006 (primarily from the Pacific acquisition), which contributed approximately 527,000 additional barrels per day and $42 million of additional revenues during the third quarter of 2007 compared to the third quarter of 2006 and approximately 647,000 additional barrels per day and $132 million of additional revenues during the first nine months of 2007 compared to the first nine months of 2006;

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higher volumes on our Basin and Capline systems primarily from multi-year contracts entered into during the second quarter of 2006;

increased trucking revenues primarily resulting from an increase in rates of approximately 13% during 2007;

higher volumes on various other systems; and

An increase of approximately $7 million and $13 million for the third quarter and first nine months of 2007, respectively, from our loss allowance oil, primarily resulting from increased prices and increased volumes. 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 subsequent sales of allowance oil barrels are also included in tariff revenues.

Increased field operating costs Field operating costs have increased for most categories of costs for the third quarter and first nine months of 2007 compared to the third quarter and first nine months of 2006 as we have continued to grow through acquisitions and expansion projects. The most significant cost increases in the third quarter and first nine months of 2007 (primarily from recent acquisitions) have been related to (i) payroll and benefits, (ii) utilities, (iii) pipeline integrity work and (iv) property taxes.

Increased segment G&A expenses Segment G&A expenses excluding equity compensation charges increased in the third quarter and first nine months of 2007 compared to the third quarter and first nine months of 2006 primarily as a result of the acquisitions and internal growth projects discussed above.

Increased equity compensation expenses Equity compensation charges included in field operating costs and segment G&A expenses decreased approximately $5 million in the third quarter of 2007 over the third quarter of 2006, primarily as a result of a decrease in the fair value of our outstanding LTIP awards related to a decrease in our closing unit price to $54.49 at September 30, 2007 from $63.65 at June 30, 2007 offset by additional LTIP grants. Equity compensation charges included in field operating costs and segment G&A expenses increased approximately $8 million in the first nine months of 2007 over the first nine months of 2006, primarily as a result of additional LTIP grants. See Note 8 to our Condensed Consolidated Financial Statements.

Maintenance capital investment for the nine months ended September 30, 2007 was approximately $22 million, compared to approximately $12 million for the nine months ended September 30, 2006. The increase is due to our continued growth through acquisitions.

Facilities

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

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Change $	Change %	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	Change $	Change %
Operating Results (in millions, except per barrel amounts)								
Storage and terminalling revenues [1]	$ 54.0	$ 21.3	$ 32.7	154%	$ 153.3	$ 54.6	$ 98.7	181%
Field operating costs (excluding equity compensation charge)	(22.1)	(9.5)	(12.6)	133%	(62.3)	(23.9)	(38.4)	161%
Equity compensation charge operations [3]				N/A	(0.1)		(0.1)	N/A
Segment G&A expenses (excluding equity compensation charge) [2]	(5.2)	(2.8)	(2.4)	86%	(14.7)	(9.8)	(4.9)	50%
Equity compensation charge general and administrative [3]	(0.3)	(1.3)	1.0	(77)%	(5.5)	(3.5)	(2.0)	57%
Equity in earnings in unconsolidated entities	2.3	1.3	1.0	77%	8.8	2.2	6.6	300%
Segment profit	$ 28.7	$ 9.0	$ 19.7	219%	$ 79.5	$ 19.6	$ 59.9	306%
Maintenance capital investment	$ 0.2	$ 1.9	$ (1.7)	(89)%	$ 6.4	$ 3.4	$ 3.0	88%
Segment profit per barrel	$ 0.23	$ 0.14	$ 0.09	64%	$ 0.22	$ 0.10	$ 0.12	120%
Volumes [4]								
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	39.6	18.8	20.8	111%	36.9	18.8	18.1	96%
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	12.9		0%	12.9	12.4	0.5	4%
LPG and crude processing (thousands of barrels per day)	20.8	16.3	4.5	28%	18.2	11.5	6.7	58%
Facilities Activities Total (average monthly capacity in millions of barrels) [5]	42.4	21.4	21.0	98%	39.6	21.2	18.4	87%

(1) Revenues include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(3) Compensation expense related to our equity compensation plans.

(4) Volumes associated with acquisitions represent total volumes for the number of months we actually owned the assets divided by the number of months in the

period.

(5) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the ratio of 6:1 mcf of gas to one barrel of crude oil; and (iii) LPG and crude processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly capacity in millions.

Segment profit and segment profit per barrel, our primary measures of segment performance, were impacted by the following:

Increased volumes and related revenues The increase in volumes and revenues is attributable to a combination of the following factors:

Acquisitions and expansion projects attributable to crude and LPG facilities The increase in volumes and related revenues during the third quarter and first nine months of 2007 primarily relates to (i) the acquisition of the Bumstead LPG storage facility in late July of 2007, the acquisition of Pacific in the fourth quarter of 2006 and other acquisitions completed during 2006, and (ii) additional capacity resulting from the second quarter completion of Phase I of the St. James construction project, which brought the capacity at St. James to 3.5 million barrels;

Refined product storage and terminalling We had no revenue from refined products storage and terminalling until the acquisition of Pacific, which contributed additional refined products storage and terminalling revenues of approximately $10 million and $30 million in the third quarter and first nine months of 2007, respectively; and

LPG processing The acquisition of the Shafter processing facility during the second quarter of 2006 resulted in additional processing revenues and volume for the third quarter and first nine months of 2007.

Increased field operating costs Our continued growth, primarily from the acquisitions completed during 2006 and the additional tankage added in 2007 and 2006, is the principal cause of the increase in field operating costs in the third quarter and first nine months of 2007. The significant components of the increased costs are detailed below:

Increases of approximately $1 million and $7 million for the three and nine months ended September 30, 2007, respectively, related to the operating costs associated with the Shafter processing facility, which we acquired in the Andrews acquisition in the second quarter of 2006;

Increases of approximately $9 million and $24 million for the three and nine months ended September 30, 2007, respectively, related to the operating costs associated with the Pacific acquisition; and

Increases of approximately $1 million and $2 million for the three and nine months ended September 30, 2007, respectively, related to the operating costs associated with Phase I of the St. James facility, which became operational during 2007.

Increased segment G&A expenses Segment G&A expenses excluding equity compensation charges increased in the third quarter and first nine months of 2007 compared to the same periods in 2006, primarily as a result of the acquisitions and internal growth projects discussed above;

Increased equity compensation expenses Equity compensation charges included in field operating costs and segment G&A expenses decreased approximately $1 million in the third quarter of 2007 over the third quarter of 2006, primarily as a result of a decrease in the fair value of our outstanding LTIP awards related to a decrease in our closing unit price to $54.49 at September 30, 2007 from $63.65 at June 30, 2007 offset by additional LTIP grants. Equity compensation charges included in field operating costs and segment G&A expenses increased approximately $2 million in the first nine months of 2007 over the first nine months of 2006, primarily as a result of additional LTIP grants. See Note 8 to our Condensed Consolidated Financial Statements.

Increased equity earnings in unconsolidated entities Our investment in PAA/Vulcan contributed approximately $1 million and $7 million in additional earnings for the third quarter and first nine months of 2007, respectively, compared to the corresponding periods of 2006, reflecting increased value for leased storage.

Maintenance capital investment for the nine months ended September 30, 2007 was approximately $6 million, compared to approximately $3 million for the nine months ended September 30, 2006. The increase for the nine months ended September 30, 2007 is due to continued growth through acquisitions.

Marketing

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

Operating Results (in millions except per barrel amounts) [1]	Three Months Ended September 30, 2007	2006	Change $	%	Nine Months Ended September 30, 2007	2006	Change $	%
Revenues [2] [3]	$ 5,668.0	$ 4,430.4	$ 1,237.6	28%	$ 13,565.1	$ 17,788.1	$ (4,223.0)	(24)%
Purchases and related costs [4] [5]	(5,555.9)	(4,304.8)	(1,251.1)	29%	(13,168.6)	(17,462.5)	4,293.9	(25)%
Field operating costs (excluding equity compensation charge)	(38.3)	(35.2)	(3.1)	9%	(114.9)	(99.9)	(15.0)	15%
Equity compensation charge operations [6]				N/A	(0.3)	(0.1)	(0.2)	200%
Segment G&A expenses (excluding equity compensation charge) [7]	(13.2)	(10.2)	(3.0)	29%	(39.0)	(28.0)	(11.0)	39%
Equity compensation charge general and administrative [6]	(0.3)	(4.0)	3.7	(93)%	(14.8)	(10.3)	(4.5)	44%
Segment profit [3]	$ 60.3	$ 76.2	$ (15.9)	(21)%	$ 227.5	$ 187.3	$ 40.2	21%
SFAS 133 mark-to-market adjustment [3]	$ (14.6)	$ 17.9	$ (32.5)	(182)%	$ (16.5)	$ 14.8	$ (31.3)	(211)%
Maintenance capital investment	$ 0.5	$ 1.0	$ (0.5)	(50)%	$ 3.6	$ 2.2	$ 1.4	64%
Segment profit per barrel [8]	$ 0.79	$ 1.08	$ (0.29)	(27)%	$ 0.98	$ 0.92	$ 0.06	6%
Average Daily Volumes (thousands of barrels per day) [9]								
Crude oil lease gathering	679	650	29	4%	689	639	50	8%
Refined products	14	N/A	14	N/A	10	N/A	10	N/A
LPG sales	58	39	19	49%	78	49	29	59%
Waterborne foreign crude imported	82	80	2	3%	76	59	17	29%
	833	769	64	8%	853	747	106	14%

Marketing Activities Total

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

(2) Includes revenues associated with buy/sell arrangements of approximately $4,762 million for the nine months ended September 30, 2006. Volumes associated with these arrangements were approximately 919,500 barrels per day for the nine months ended September 30, 2006.

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

(4) Includes purchases associated with buy/sell arrangements of approximately $4,795 million for the nine months ended September 30,

2006. Volumes associated with these arrangements were approximately 926,800 barrels per day for the nine months ended September 30, 2006.

(5) Purchases and related costs include interest expense on contango inventory purchases of approximately $13 million and $15 million for the third quarter of 2007 and 2006, respectively, and approximately $38 million and $36 million for the nine months ended September 30, 2007 and 2006, respectively.

(6) Compensation expense related to our equity compensation plans.

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(7) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(8) Calculated based on crude oil lease gathered volumes, refined products volumes, LPG sales volumes, and waterborne foreign crude volumes.

(9) Volumes associated with acquisitions represent total volumes for the number of days we actually owned the assets divided

by the number of days in the period.

Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our marketing segment profit to increase or decrease directionally with increases or decreases in our marketing segment volumes, as well as the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. 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 and our risk management activities provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and will vary from period to period. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as we have recently experienced, and these operating results may not be indicative of sustainable performance. See Outlook.

Segment profit and segment profit per barrel, our primary measures of segment performance, were impacted by the following:

Revenues Our revenues for the third quarter increased compared to the third quarter of 2006 primarily due to an increase in volumes and an increase in the average NYMEX price for crude oil. Our revenues for the first nine months of 2007 decreased compared to the first nine months of 2006 partially due to a decrease in the average NYMEX price for crude oil. The NYMEX averages were $74.99 and $66.14 for the third quarter and first nine months of 2007, respectively, as compared to $70.64 and $68.26 for the third quarter and first nine months of 2006, respectively. Our revenues also decreased for the first nine months of 2007 compared to the first nine months of 2006 due to the adoption in the second quarter of 2006 of EITF Issue No. 04-13, Accounting for Purchases and Sales of Inventory with the Same Counterparty (EITF 04-13). According to EITF 04-13, 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 adoption of EITF 04-13 in the second quarter of 2006 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. 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.

Acquisitions During the last nine months of 2006 and the first nine months of 2007, we purchased certain crude oil gathering assets and related contracts in South Louisiana, completed the acquisitions of Pacific and Andrews Petroleum and Lone Star Trucking (Andrews), and purchased a refined products supply and marketing business. These transactions primarily affected our transportation and facilities segment, but also included some marketing activities and opportunities. The integration into our business of these marketing activities precludes specific quantification of relative contribution, but we believe these acquisitions increased segment profit and revenues for our marketing segment.

Favorable market conditions and execution of our risk management strategies During the third quarter and first nine months of 2007 and 2006, the crude oil market experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil ranged from $68.63 to $83.90 during the third quarter of 2007 and from $49.90 to $83.90 for the first nine months of 2007. The NYMEX WTI crude oil benchmark prices reached a record high of over $83 per barrel in September 2007, exceeding the previous high of over $78 per barrel reached in July of 2006. The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of our gathering and marketing activities. The volatile market also led to favorable basis differentials for various delivery points and grades of crude oil during the first half of 2007. However, as the third quarter of 2007 progressed, these favorable basis differentials began to narrow.

From early 2005 through the end of June 2007, the market for crude oil generally was volatile and in contango, meaning that the price of crude oil for future deliveries was higher than current prices. A contango market is favorable to our commercial strategies that are associated with storage tankage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. In July 2007, the market for crude oil transitioned rapidly to a backwardated market, meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries, however, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. The monthly time-spread of prices averaged approximately $0.67 for the first nine months of 2007 versus $1.11 for the first nine months of 2006. The monthly time-spread of prices averaged approximately $(0.44) (backwardation) for the third quarter of 2007 versus $1.12 (contango) for the third quarter of 2006.

Marketing segment profit is net of contango and other hedged inventory-related interest expense (which is incurred to store the crude oil) of approximately $13 million and $38 million for the third quarter and first nine months of 2007, respectively (compared to approximately $15 million and $36 million in the third quarter and first nine months of 2006, respectively). This cost is included in Purchases and related costs in the table above.

SFAS 133 mark-to-market The third quarter and first nine months of 2007 includes SFAS 133 mark-to-market losses of approximately $15 million and $17 million, respectively, compared to gains of approximately $18 million and $15 million for the third quarter and first nine months of 2006, respectively. See Note 9 to our Condensed Consolidated Financial Statements.

Field operating costs and segment G&A expenses Field operating costs (excluding equity compensation charges) increased in the third quarter and first nine months of 2007 compared to the third quarter and first nine months of 2006, primarily as a result of increases in contract transportation as a result of 2006 acquisitions and changes in driver incentive programs. The increase in general and administrative expenses (excluding equity compensation charges) is primarily the result of increased payroll and benefits (partly due to the early retirement of an executive), additional overhead allocation, as well as acquisitions and internal growth, as discussed above.

Increased equity compensation expenses Equity compensation charges included in field operating costs and segment G&A expenses decreased approximately $4 million in the third quarter of 2007 over the third quarter of 2006, primarily as a result of a decrease in the fair value of our outstanding LTIP awards related to a decrease in our closing unit price to $54.49 at September 30, 2007 from $63.65 at June 30, 2007 offset by additional LTIP grants. Equity compensation charges included in field operating costs and segment G&A expenses increased approximately $5 million in the first nine months of 2007 over the first nine months of 2006, primarily as a result of additional LTIP grants. See Note 8 to our Condensed Consolidated Financial Statements.

Maintenance capital investment for the nine months ended September 30, 2007 was approximately $4 million, compared to approximately $2 million for the nine months ended September 30, 2006. The increase for the nine months ended September 30, 2007 is due to continued growth through acquisitions.

Other Expenses

Depreciation and Amortization. Depreciation and amortization expense increased $19 million and $68 million for the third quarter and first nine months of 2007, respectively, compared to the comparable 2006 periods, primarily as a result of a continued expansion in our asset base from acquisitions and internal growth projects. A net gain of approximately $1 million from the disposition of assets is also included in depreciation expense for the third quarter of 2007. A net loss of approximately $8 million from the disposition of assets is also included in depreciation expense for the first nine months of 2007. Amortization of debt issue costs totaled approximately $1 million and $2 million for the third quarter and first nine months of 2007, respectively, and was relatively constant compared to the same periods in 2006.

Interest Expense. Interest expense increased approximately 102% and 131% in the third quarter and first nine months of 2007, respectively, as compared to the third quarter and first nine months of 2006, primarily due to higher average debt balances during 2007 partially offset by increased capitalized interest associated with certain capital projects under construction. The higher average debt balance in the first nine months of 2007 was primarily related to the addition or assumption of $1.7 billion of senior notes in the last nine months of 2006 to finance acquisitions. Our financial growth strategy is to fund our acquisitions and expansion capital expenditures with at least 50% equity and excess cash flow over distributions, with the balance funded through long-term debt.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our marketing 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.

Income Taxes. As a result of recent Canadian tax legislation that may apply to a portion of our Canadian activities, we recorded an approximate $11 million deferred tax provision related to the cumulative effect of this tax, which is primarily attributable to prior years. Pursuant to a safe harbor provision of the legislation, we do not expect the tax to apply to us until 2011. See Note 11 to our Condensed Consolidated Financial Statements.

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 that, 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 current operations, but with respect to which these resources effectively can be applied. For example, during the first quarter of 2007, we entered the refined products marketing business and during 2006 we entered the refined products transportation and storage business as well as the barge transportation business. Through PAA/Vulcan s acquisition of ECI in 2005, the Partnership entered the natural gas storage business. We are presently engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses described above, 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.

Pipeline Integrity and Storage Tank Testing Compliance

Although we believe our short-term estimates of costs under the pipeline integrity management rules and API 653 (and similar regulations in Canada) are reasonable, a high degree of uncertainty exists with respect to estimating such costs, as we continue to test existing assets and as we acquire additional assets. In our annual report on Form 10-K for the year ended December 31, 2006, we reported that the DOT will be issuing by December 31, 2007, new regulations governing hazardous liquid pipelines operated at low stress. We do not expect these new regulations to have a material impact on operating expenses. See Note 12 to our Condensed Consolidated Financial Statements.

General Market Conditions

From early 2005 through the end of June 2007, the market for crude oil generally has been volatile and in contango. In July 2007, the market for crude oil transitioned rapidly to a backwardated market. See Results of Operations *Marketing* above for additional detail and the impact of these market conditions on our business. We believe that the combination of our lease gathering activities and the commercial strategies used with our tankage provides a counter-cyclical balance that has a stabilizing effect on our operations and enables us to generate a base level of cash flow.

The wide contango spreads experienced over the last couple of years, combined with the level of price structure volatility during that time period has enabled us to generate not only a base level of cash flow, but in certain instances to generate significant additional profitability. While we believe that the counter-cyclical balance provided by our asset base and our business model will enable us to continue to generate a solid base level of cash flow in the current backwardated environment, if the market remains in the current backwardated structure, our future results from our marketing segment may be less that those generated during the more favorable periods of pronounced contango experienced over the last 24 to 30 months. In most cases, our profitability during a backwardated market would be enhanced if there is volatility in the pricing structure.

Longer-Term Outlook

In our annual report on Form 10-K for the year ended December 31, 2006, we identified certain trends, factors and developments, many of which are beyond our control, that may affect our business in the future. We believe the collective impact of these trends, factors and developments will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings, which were evident during the past two and a half years. 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.

In addition to our crude oil business, we also identified certain trends that we believe will provide opportunities for PAA/Vulcan s natural gas storage business and our refined products business. We intend to grow both of these businesses through the application of our business model as well as future acquisitions and expansion projects.

Liquidity and Capital Resources

Liquidity

Cash flow from operations and borrowings under our credit facilities are our primary sources of liquidity. At September 30, 2007, we had a working capital surplus of approximately $165 million, approximately $1.5 billion of availability under our committed revolving credit facilities and approximately $0.8 billion of availability under our uncommitted hedged inventory facility. Our working capital increased approximately $32 million in the first nine months of 2007. See *Cash flow from operations,* below, for discussion of the relationship between working capital items and our short-term borrowings. Usage of the credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Cash flow from operations

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products and other expenses, principally field operating costs and general and administrative expenses.

The storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices, can have a material impact on our cash flows from operating activities. 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. Similarly, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end 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 it is purchased and do not rely on borrowings under our credit facilities to pay for the crude oil. During such markets, our accounts payable and accounts receivable generally move in tandem 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.

In periods during which we build inventory or linefill, regardless of market structure, we may rely on our credit facilities to pay for the inventory or linefill.

The crude oil market was in contango for the first six months of 2007 and for much of 2006 and 2005. In July 2007, the market for crude oil transitioned rapidly to a backwardated market, meaning that the price of crude oil for future deliveries is lower than current prices. The wide contango spreads experienced prior to July 2007, combined with the level of price structure volatility during that time period enabled us to generate not only a base level of cash flow, but in certain instances to generate significant additional profitability. A backwardated market has a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for

prompt deliveries; however, in this environment, there is little incentive to store crude oil as current prices are above future delivery prices. While we believe that the counter-cyclical balance provided by our asset base and business model will enable us to continue to generate a solid base level of cash flow in the current backwardated environment, if the market remains in the current backwardated structure, our future results from our marketing segment may be less that those generated during the more favorable periods of pronounced contango experienced over the last 24 to 30 months. Generally, base-level results will also be augmented if there is meaningful volatility in the pricing structure.

Our cash flow provided by operating activities in the first nine months of 2007 was approximately $969 million compared to cash used in operating activities of $182 million in the first nine months of 2006. This change reflects cash generated by our recurring operations (as indicated above in describing the primary drivers of cash generated from operations), offset by changes in certain working capital items (including a decrease in inventory). A significant portion of the decreased inventory had been stored due to contango market conditions but was partly liquidated as the market transitioned into backwardation. Proceeds from liquidating inventory were used to repay borrowings under our credit facilities (see *Cash provided by equity and debt financing activities,* below). The fluctuations on our accounts receivable, inventory and accounts payable and other liabilities accounts during the period are primarily related to purchases and sales of crude oil that vary proportionately along with the fluctuations in our short-term debt balances. During the corresponding period in 2006, we shifted into a pronounced contango market and, as discussed above, experienced significant fluctuations in our working capital accounts, most notably our accounts receivable balance.

Cash provided by equity and debt financing activities

We periodically access the capital markets for both equity and debt financing. For us to maintain our targeted credit profile (a long-term debt-to-total capitalization ratio of approximately 50%, a long-term debt-to-earnings before interest, income taxes, depreciation and amortization (EBITDA) multiple of approximately 3.5x and an average EBITDA-to-interest coverage multiple of 3.3x or better) and achieve growth through internal growth projects and acquisitions, we intend to fund at least 50% of the capital requirements associated with these activities with equity and cash flow in excess of distributions.

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. In June 2007, we issued approximately 6.3 million common units under this registration statement for net proceeds of approximately $382.5 million. At September 30, 2007, we have approximately $769 million of unissued securities remaining available under this registration statement.

Cash used in financing activities was approximately $491 million for the nine months ended September 30, 2007, compared to cash provided by financing activities of approximately $976 million for the nine months ended September 30, 2006. During the nine months ended September 30, 2007 we had net repayments of our working capital and hedged inventory borrowings of approximately $543 million and during the nine months ended September 30, 2006, we had net working capital borrowings and hedged inventory borrowings of approximately $615 million. Our financing activities primarily relate to (i) funding acquisitions and internal capital projects and (ii) funding and repayments under our short-term working capital and hedged inventory facilities related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities. During the first nine months of 2007, we made repayments under our credit facilities that were financed through the issuance of equity and the partial liquidation of inventory resulting from the transition to a backwardated market. See Note 7 to our Condensed Consolidated Financial Statements for further discussion of equity issuances.

In June 2007, the borrowing capacity under our senior secured hedged inventory facility was increased from $1.0 billion to $1.2 billion under the terms and conditions of such facility, as amended. The facility has a maturity date of November 16, 2007, and we anticipate extending the facility for an additional year, subject to lender approval.

On July 31, 2007, we amended our revolving credit facility to reset the maximum debt coverage ratio during an acquisition period from 5.25 to 1.0 to 5.5 to 1.0, and extend the maturity date from July 2011 to July 2012.

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. Our primary uses of cash, in addition to normal operating expenses, 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

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Projects. The price of the acquisitions includes cash paid and transaction costs, as well as assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total value of the acquisitions completed during the year.

Distributions to common unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to common 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 in the discretion of our general partner for future requirements. We have declared and paid distributions in each quarter of 2007 and 2006. See Note 7 to our Condensed Consolidated Financial Statements.

Our general partner is entitled to incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts of its incentive distributions. The aggregate reduction in incentive distributions will be $65 million. Following the distribution in November 2007, the remaining incentive distribution reductions will be $45 million. See Note 7 to our Condensed Consolidated Financial Statements.

Contingencies

See Note 12 to our Condensed Consolidated Financial Statements.

Commitments

Contractual Obligations

The amounts presented in the table below represent the net obligations associated with leases and with buy/sell contracts and those contracts subject to a net settlement arrangement with the counterparty. Other contractual obligations did not vary significantly since December 31, 2006. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by hedged inventory borrowings and by corresponding sales to creditworthy entities.

The following table includes our best estimate of the amount and timing of these payments due under the specified contractual obligations as of September 30, 2007.

	Total	2007	2008	2009	2010	2011	2012 and Thereafter
Leases (1)	$ 239.2	$ 10.5	$ 42.6	$ 37.9	$ 27.0	$ 17.3	$103.9
Crude oil, LPG and other purchases (2)	$8,448.3	$4,487.4	$1,709.1	$858.5	$568.2	$441.1	$384.0

(1) Leases are primarily for office rent, trucks used in our gathering activities, and right of way obligations.

(2) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead,

weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit

In connection with our crude oil marketing, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At September 30, 2007, approximately $51 million of letters of credit were outstanding under our credit facility. See Note 5 to our Condensed Consolidated Financial Statements.

Capital Contributions to PAA/Vulcan Gas Storage, LLC

We and Vulcan Gas Storage LLC are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture agreement. During the first nine months of 2007, we made an additional contribution of approximately $9 million to PAA/Vulcan. Such contribution did not result in an increase to our ownership interest. Also see Note 10 to our Condensed Consolidated Financial Statements for discussion of an additional commitment through a hedge instrument with PAA/Vulcan.

Distributions

See discussion above under *Capital Expenditures and Distributions Paid to Unitholders and General Partner*.

Regulation

See Note 12 to our Condensed Consolidated Financial Statements.

Recent Accounting Pronouncements and Change in Accounting Principle

See Note 14 to our Condensed Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates in Item 7 of our 2006 Annual Report on Form 10-K.

Forward-Looking Statements and Associated Risks

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

- the failure to realize the anticipated synergies and other benefits of the merger with Pacific;
- the success of our risk management activities;
- 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 systems;
- failure to implement or capitalize on planned internal growth projects;
- shortages or cost increases of power supplies, materials or labor;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate, and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers;
- fluctuations in refinery capacity in areas supplied by our mainlines, and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transmission throughput requirements;
- 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;

weather interference with business operations or project construction;

risks related to the development and operation of natural gas storage facilities;

general economic, market or business conditions; and

other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors, such as (i) the Risk Factors discussed in Item 1A of Part II of this report, (ii) the Risks Related to Our Business discussed in Item 1A of our most recent annual report on Form 10-K and (iii) factors that are unknown or 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 Risk included in Item 7A in our 2006 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 Condensed 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, 2007 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 decrease are shown in the table below:

	Fair Value	Effect of 10% Price Decrease
	(in millions)	
Crude oil:		
Futures contracts	$ (43.8)	$ (22.8)
Swaps and options contracts	$ (41.8)	$ 46.3
LPG and other:		
Futures contracts	$	$ (5.7)
Swaps and options contracts	$ 18.6	$ (20.0)
Total Fair Value	$ (67.0)	

Interest Rate Risk

All of our senior notes are fixed-rate notes and thus not subject to market risk. Our variable-rate debt bears interest at LIBOR, prime or the bankers acceptance rate plus the applicable margin. Our variable-rate debt at September 30, 2007 was approximately $478 million and is expected to mature in 2007. The average interest rate of 5.9% is based upon rates in effect at September 30, 2007. The carrying values of the variable-rate instruments in our hedged inventory facility and credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

Currency Exchange Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period. Because a significant portion of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments may include forward exchange contracts and options. The fair value of these instruments based on current termination values is an unrealized loss of less than $1 million as of September 30, 2007.

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 the end of the period covered by this report, 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.

SEC rules also require an annual evaluation of the effectiveness of our internal control over financial reporting (internal control), and a quarterly evaluation of any changes in our internal control. In the course of such evaluations, we have made changes, and will continue to make changes, to refine and improve our internal control. We are required to disclose any change in our internal control that occurred during the quarter that has materially affected, or is reasonably likely to materially affect, our internal control. As a result of their evaluation of changes in internal control, management identified no changes during the third quarter of 2007 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 12 to our Condensed Consolidated Financial Statements.

Item 1A. RISK FACTORS

The sale or exchange of 50% or more of our capital and profits interests during any twelve-month period will result in our termination as a partnership for federal income tax purposes.

We will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. Upon termination, the partnership is deemed to be immediately reconstituted. Our termination would have no impact on our business or operations, but would have some tax impacts, including a reduction in depreciation deductions allocated to unitholders during the first period as a new partnership, which would result in a lower tax shield. Unitholders would also receive two K-1s for the year in which the termination occurred. We believe it is likely that such a termination will occur as a result of certain structural modifications to be made in connection with the pending initial public offering of our general partner.

For a discussion regarding additional risk factors, see Item 1A of our June 30, 2007 Quarterly Report on Form 10-Q and our 2006 Annual Report on Form 10-K. 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.

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

Issuer Repurchases 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, 2007 July 31, 2007	0	n/a	n/a	n/a
August 1, 2007 August 31, 2007	8,750(1)	$ 56.38	n/a	n/a
September 1, 2007 September 30, 2007	0	n/a	n/a	n/a
TOTAL	8,750			

(1) In August 2007, we purchased 8,750 common units from our general partner for an average price of $56.38 per unit. The common units were used to satisfy our obligations with respect to awards that vested under our 1998 LTIP.

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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

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).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 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 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).
3.4	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).
3.5	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, File No. 333-68446).
3.6	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001, File No. 333-68446).
3.7	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).
3.8	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).
3.9	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.10	Certificate of Incorporation of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Bylaws of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.13	Third Amended and Restated Agreement of Limited Partnership of Plains AAP, L.P. dated August 29, 2007 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 31, 2007).

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 May 12, 2006 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 12, 2006).
4.8	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing International GP LLC, Plains Marketing International, L.P., Plains LPG Marketing, L.P. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.10	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.12	Eleventh Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Pacific Energy Finance Corporation, Rangeland Marketing Company and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.13	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1 / 8% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.14	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1/8% senior notes due 2014 (incorporated by reference to Exhibit 4.1 to Pacific s Current Report on Form 8-K filed March 9, 2005).

4.15	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1/8% senior notes due 2014 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.16	Third Supplemental Indenture dated November 15, 2006 to Indenture dated as of June 16, 2004, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Rangeland Marketing Company, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, Plains Marketing Canada, L.P., PMC (Nova Scotia) Company, 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 Marketing International L.P., Plains LPG Marketing, L.P., PAA Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed November 21, 2006).

4.17	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 6 1/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific s Current Report on Form 8-K filed September 28, 2005).
4.18	First Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 23, 2005, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Rangeland Marketing Company, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, Plains Marketing Canada, L.P., PMC (Nova Scotia) Company, 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 Marketing International L.P., Plains LPG Marketing, L.P., PAA Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
10.1	Joinder and Supplement dated effective June 20, 2007 among the Lenders party thereto, relating to the Restated Credit Facility dated November 19, 2004, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2007).
10.2	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
/**10.3	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R Coiner.
**10.4	Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 31, 2007).
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.

** Management compensatory

plan or
arrangement.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned 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, 2007

By: /s/ GREG L. ARMSTRONG

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

Date: November 7, 2007

By: /s/ PHIL KRAMER

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

Index to Exhibits

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).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 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 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).
3.4	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).
3.5	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, File No. 333-68446).
3.6	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001, File No. 333-68446).
3.7	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).
3.8	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).
3.9	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.10	Certificate of Incorporation of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Bylaws of Pacific Energy Finance Corporation (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.12	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.13	Third Amended and Restated Agreement of Limited Partnership of Plains AAP, L.P. dated August 29, 2007 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 31, 2007).

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 May 12, 2006 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 12, 2006).
4.8	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., Plains LPG Services GP LLC, Plains LPG Services, L.P., Lone Star Trucking, LLC and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.9	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., Plains Marketing International GP LLC, Plains Marketing International, L.P., Plains LPG Marketing, L.P. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.10	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.11	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.12	Eleventh Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 25, 2002, among Plains All American Pipeline, L.P., PAA Finance Corp., PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Pacific Energy Finance Corporation, Rangeland Marketing Company and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.13	Indenture dated June 16, 2004 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1/8% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
4.14	First Supplemental Indenture dated March 3, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1/8% senior notes due 2014 (incorporated by reference to Exhibit 4.1 to Pacific s Current Report on Form 8-K filed March 9, 2005).

4.15	Second Supplemental Indenture dated September 23, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 7 1/8% senior notes due 2014 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.16	Third Supplemental Indenture dated November 15, 2006 to Indenture dated as of June 16, 2004, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Rangeland Marketing Company, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, Plains Marketing Canada, L.P., PMC (Nova Scotia) Company, 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 Marketing International L.P., Plains LPG Marketing, L.P., PAA Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed November 21, 2006).

4.17	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P. and Pacific Energy Finance Corporation, the guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 61/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific s Current Report on Form 8-K filed September 28, 2005).
4.18	First Supplemental Indenture dated November 15, 2006 to Indenture dated as of September 23, 2005, among Plains All American Pipeline, L.P., Pacific Energy Finance Corporation, PEG Canada GP LLC, Pacific Energy Group LLC, PEG Canada, L.P., Pacific Marketing and Transportation LLC, Rocky Mountain Pipeline System LLC, Ranch Pipeline LLC, Pacific Atlantic Terminals LLC, Pacific L.A. Marine Terminal LLC, Rangeland Pipeline Company, Aurora Pipeline Company Ltd., Rangeland Pipeline Partnership, Rangeland Northern Pipeline Company, Rangeland Marketing Company, Plains Marketing, L.P., Plains Pipeline, L.P., Plains Marketing GP Inc., Plains Marketing Canada LLC, Plains Marketing Canada, L.P., PMC (Nova Scotia) Company, 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 Marketing International L.P., Plains LPG Marketing, L.P., PAA Finance Corp. and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
10.1	Joinder and Supplement dated effective June 20, 2007 among the Lenders party thereto, relating to the Restated Credit Facility dated November 19, 2004, as amended (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2007).
10.2	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
/**10.3	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R Coiner.
**10.4	Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 31, 2007).
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.

** Management compensatory

plan or
arrangement.