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

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2006

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

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

At April 24, 2006, there were outstanding 77,273,248 Common Units.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	March 31, 2006 (unaudited)	December 31, 2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 9.3	$ 9.6
Trade accounts receivable and other receivables, net	1,242.8	781.0
Inventory	1,027.4	910.3
Other current assets	94.9	104.3
Total current assets	2,374.4	1,805.2
PROPERTY AND EQUIPMENT	2,177.9	2,116.1
Accumulated depreciation	(278.4)	(258.9)
	1,899.5	1,857.2
OTHER ASSETS		
Pipeline linefill in owned assets	180.1	180.2
Inventory in third party assets	71.9	71.5
Investment in PAA/Vulcan Gas Storage, LLC	113.3	113.5
Other, net	94.5	92.7
Total assets	$ 4,733.7	$ 4,120.3
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 1,265.1	$ 1,293.6
Due to related parties	6.9	6.8
Short-term debt	875.8	378.4
Other current liabilities	146.3	114.5
Total current liabilities	2,294.1	1,793.3
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	4.4	4.7
Senior notes, net of unamortized discount of $2.9 and $3.0, respectively	947.1	947.0
Other long-term liabilities and deferred credits	49.4	44.6
Total liabilities	3,295.0	2,789.6
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS CAPITAL		
Common unitholders (76,105,024 and 73,768,576 units outstanding at March 31, 2006 and December 31, 2005, respectively)	1,400.0	1,294.1
General partner	38.7	36.6
Total partners capital	1,438.7	1,330.7
Total liabilities and partners capital	$ 4,733.7	$ 4,120.3

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

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

	Three Months Ended March 31, 2006 (unaudited)	2005
REVENUES		
Crude oil and LPG sales (includes approximately $4,717.7 and $3,467.0 in the first quarter of 2006 and 2005, respectively, related to buy/sell transactions)	$ 8,372.0	$ 6,417.8
Other gathering, marketing, terminalling and storage revenues	16.5	8.2
Pipeline margin activities revenues (includes approximately $45.3 and $33.5 in the first quarter of 2006 and 2005, respectively, related to buy/sell transactions)	193.9	157.6
Pipeline tariff activities revenues	53.0	54.9
Total revenues	8,635.4	6,638.5
COSTS AND EXPENSES		
Crude oil and LPG purchases and related costs (includes approximately $4,749.4 and $3,397.0 in the first quarter of 2006 and 2005, respectively, related to buy/sell transactions)	8,239.1	6,334.7
Pipeline margin activities purchases (includes approximately $45.7 and $31.5 in the first quarter of 2006 and 2005, respectively, related to buy/sell transactions)	188.3	151.5
Field operating costs	82.3	63.8
General and administrative expenses	31.8	22.1
Depreciation and amortization	21.6	19.1
Total costs and expenses	8,563.1	6,591.2
OPERATING INCOME	72.3	47.3
OTHER INCOME (EXPENSE)		
Equity earnings (loss) in PAA/Vulcan Gas Storage, LLC	(0.2)	
Interest expense (net of capitalized interest of $0.6 and $0.6, respectively)	(15.3)	(14.6)
Interest income and other, net	0.3	0.1
Income before cumulative effect of change in accounting principle	57.1	32.8
Cumulative effect of change in accounting principle	6.3	
NET INCOME	$ 63.4	$ 32.8
NET INCOME-LIMITED PARTNERS	$ 56.7	$ 29.3
NET INCOME-GENERAL PARTNER	$ 6.7	$ 3.5
BASIC NET INCOME PER LIMITED PARTNER UNIT		
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.65	$ 0.43
Cumulative effect of change in accounting principle per limited partner unit	0.08	
Basic net income per limited partner unit	$ 0.73	$ 0.43
DILUTED NET INCOME PER LIMITED PARTNER UNIT		
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.63	$ 0.43
Cumulative effect of change in accounting principle per limited partner unit	0.08	
Diluted net income per limited partner unit	$ 0.71	$ 0.43
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	74.0	67.5
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	75.7	68.2

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

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

	Three Months Ended March 31, 2006 (unaudited)	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 63.4	$ 32.8
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	21.6	19.1
Cumulative effect of change in accounting principle	(6.3)	
SFAS 133 mark-to-market adjustment	0.7	13.4
Long-Term Incentive Plan expense	10.6	2.2
Noncash amortization of terminated interest rate hedging instruments	0.4	0.4
Loss on foreign currency revaluation	0.9	0.6
Equity (earnings) loss in PAA/Vulcan Gas Storage, LLC	0.2	
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(431.2)	(554.8)
Inventory	(116.0)	(208.0)
Accounts payable and other current liabilities	(3.2)	420.0
Due to related parties	1.3	2.4
Net cash used in operating activities	(457.6)	(271.9)
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 3)	(17.5)	(13.5)
Additions to property and equipment	(62.7)	(50.0)
Cash paid for linefill in assets owned	(4.3)	
Proceeds from sales of assets	0.2	1.8
Net cash used in investing activities	(84.3)	(61.7)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings (repayments) on long-term revolving credit facility		(18.3)
Net borrowings (repayments) on working capital revolving credit facility	(5.1)	41.8
Net borrowings on short-term letter of credit and hedged inventory facility	503.4	344.6
Net proceeds from the issuance of common units (Note 7)	101.4	22.3
Distributions paid to unitholders and general partner (Note 7)	(57.3)	(45.0)
Other financing activities	(0.9)	(2.8)
Net cash provided by financing activities	541.5	342.6
Effect of translation adjustment on cash	0.1	(0.1)
Net increase (decrease) in cash and cash equivalents	(0.3)	8.9
Cash and cash equivalents, beginning of period	9.6	12.9
Cash and cash equivalents, end of period	$ 9.3	$ 21.8
Cash paid for interest, net of amounts capitalized	$ 17.5	$ 13.2

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

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

	Common Units Units	Amount	General Partner Amount (unaudited)	Total Partners Capital Amount
Balance at December 31, 2005	**73.8**	**$ 1,294.1**	**$ 36.6**	**$ 1,330.7**
Net Income		56.7	6.7	63.4
Distributions		(50.7)	(6.6)	(57.3)
Issuance of common units	2.3	99.4	2.0	101.4
Other comprehensive income		0.5		0.5
Balance at March 31, 2006	**76.1**	**$ 1,400.0**	**$ 38.7**	**$ 1,438.7**

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended March 31, 2006 (unaudited)	2005
Net income	$ 63.4	$ 32.8
Other comprehensive income (loss)	0.5	(69.8)
Comprehensive income (loss)	$ 63.9	$ (37.0)

CONSOLIDATED STATEMENT OF
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Net Deferred Gain (Loss) on Derivative Instruments (unaudited)	Currency Translation Adjustments	Total
Balance at December 31, 2005	$ (16.6)	$ 87.1	$ 70.5
Current period activity:			
Reclassification adjustment for settled contracts	(46.1)		(46.1)
Changes in fair value of outstanding hedge positions	48.8		48.8
Currency translation adjustment		(2.2)	(2.2)
Total period activity	2.7	(2.2)	0.5
Balance at March 31, 2006	$ (13.9)	$ 84.9	$ 71.0

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

Note 1 Organization and Accounting Policies

Plains All American Pipeline, L.P. (PAA) is a Delaware limited partnership formed in September 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as LPG. We own an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. In addition, through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we are engaged in the development and operation of natural gas storage facilities.

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

Note 2 Trade Accounts Receivable

The majority of our trade accounts receivable relates to our gathering and marketing activities, which can generally be described as high volume and low margin activities. As is customary in the industry, a portion of these receivables is reflected net of payables to the same counterparty based on contractual agreements. We routinely review our trade accounts receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered, received or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses, as well as our historical experience and the facts and circumstances surrounding certain aged balances, we have established an allowance for doubtful trade accounts receivable. At March 31, 2006, substantially all of our net trade accounts receivable were less than 60 days past the scheduled invoice date. The following is a summary of the changes in our allowance for doubtful trade accounts receivable balance (in millions):

Balance at December 31, 2005	$ 0.8
Applied to accounts receivable balances	(0.4)
Charged to expense	0.1
Balance at March 31, 2006	$ 0.5

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

Note 3 Acquisitions

During the first quarter of 2006, we paid into escrow approximately $17 million related to an acquisition which subsequently closed in April 2006. Also, during March 2006, we signed an agreement to acquire 100% of the equity interests of Andrews Petroleum, Inc. and Lone Star Trucking, Inc. for approximately $205 million. Andrews and Lone Star provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (NGLs) throughout the Western United States. The acquisiton closed in April 2006 and will be reflected in our gathering, marketing, terminalling and storage operations (GMT&S) segment in the second quarter of 2006. See Note 14 to our Consolidated Financial Statements for a discussion of additional acquisition activity subsequent to March 31, 2006.

Note 4 Inventory and Linefill

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

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

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

	March 31, 2006			December 31, 2005		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory						
Crude oil	16,081	$ 953.0	$ 59.26	13,887	$ 755.7	$ 54.42
LPG	1,715	68.7	$ 40.06	3,649	149.0	$ 40.83
Parts and supplies	N/A	5.7	N/A	N/A	5.6	N/A
Inventory subtotal	17,796	1,027.4		17,536	910.3	
Inventory in third-party assets						
Crude oil	1,248	59.9	$ 48.00	1,248	58.6	$ 46.96
LPG	318	12.0	$ 37.74	318	12.9	$ 40.57
Inventory in third-party assets subtotal	1,566	71.9		1,566	71.5	
Linefill						
Crude oil	6,207	179.2	$ 28.87	6,207	179.3	$ 28.89
LPG	27	0.9	$ 33.33	27	0.9	$ 33.33
Linefill subtotal	6,234	180.1		6,234	180.2	
Total	25,596	$ 1,279.4		25,336	$ 1,162.0	

Note 5 Debt

Below is a description of our debt:

	March 31, 2006 (in millions)	December 31, 2005
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 5.3% and 4.8% at March 31, 2006 and December 31, 2005, respectively	$ 722.7	$ 219.3
Working capital borrowings, bearing interest at a rate of 5.5% and 5.0% at March 31, 2006 and December 31, 2005, respectively(1)	149.9	155.4
Other	3.2	3.7
Total short-term debt	875.8	378.4
Long-term debt:		
4.75% senior notes due August 2009, net of unamortized discount of $0.5 million and $0.6 million at March 31, 2006 and December 31, 2005, respectively	174.5	174.4
7.75% senior notes due October 2012, net of unamortized discount of $0.2 million and $0.2 million at March 31, 2006 and December 31, 2005, respectively	199.8	199.8
5.63% senior notes due December 2013, net of unamortized discount of $0.5 million and $0.5 million at March 31, 2006 and December 31, 2005, respectively	249.5	249.5
5.25% senior notes due June 2015, net of unamortized discount of $0.7 and $0.7 million at March 31, 2006 and December 31, 2005, respectively	149.3	149.3
5.88% senior notes due August 2016, net of unamortized discount of $1.0 million and $1.0 million at March 31, 2006 and December 31, 2005, respectively	174.0	174.0
Senior notes, net of unamortized discount(2)	947.1	947.0
Long-term debt under credit facilities and other	4.4	4.7
Total long-term debt(1)(2)	951.5	951.7
Total debt	$ 1,827.3	$ 1,330.1

(1) At March 31, 2006 and December 31, 2005, we have classified $149.9 million and $155.4 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) margin deposits.

(2) At March 31, 2006, the aggregate fair value of our fixed-rate senior notes is estimated to be approximately $951 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 reflect market.

Note 6 Earnings Per Limited Partner Unit

Except as discussed below, basic and diluted net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner interest (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units during the period. Subject to applicability of EITF No. 03-06 (EITF 03-06), Participating Securities and the Two-Class Method under FASB Statement No. 128, Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership.

The following sets forth the computation of basic and diluted earnings per limited partner unit. The weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents at March 31, 2006 and 2005.

	Three Months Ended March 31, 2006	2005
	(in millions, except per unit data)	
Numerator:		
Net income	$ 63.4	$ 32.8
Less: General partner s incentive distribution paid	(5.5)	(2.9)
Subtotal	57.9	29.9
General partner 2% ownership	(1.2)	(0.6)
Net income available to limited partners	56.7	29.3
Pro forma additional general partner s incentive distribution(1)	(2.9)	
Net income available to limited partners under EITF 03-06	53.8	29.3
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	$ 47.6	$ 29.3
Denominator:		
Basic earnings per limited partner unit (weighted average number of limited partner units outstanding)	74.0	67.5
Effect of dilutive securities:		
Weighted average LTIP units (see Note 8)	1.7	0.7
Diluted earnings per limited partner unit (weighted average number of limited partner units outstanding)	75.7	68.2
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.65	$ 0.43
Cumulative effect of change in accounting principle per limited partner unit	0.08	
Basic net income per limited partner unit	$ 0.73	$ 0.43
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.63	$ 0.43
Cumulative effect of change in accounting principle per limited partner unit	0.08	
Diluted net income per limited partner unit	$ 0.71	$ 0.43

(1) Under EITF 03-06, when the Partnership s aggregate net income exceeds the aggregate distribution made during such period, earnings per limited partner unit are calculated as if all of the earnings for the period were distributed, regardless of the pro forma nature of the allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

Note 7 Partners Capital and Distributions

Direct Placement of Common Units

On March 22, 2006, we issued 2,336,448 common units pursuant to our existing shelf registration statement in a direct placement to a group of funds affiliated with institutional investors. The sale price for the common units was $42.80 per unit resulting in net proceeds of approximately $101 million, including the general partner s proportionate capital contribution. In addition, in April 2006, upon closing of the Andrews Petroleum, Inc. acquisition, these investors purchased 1,168,224 additional common units at the same price as noted above, representing an incremental $51 million in proceeds, including the general partner s proportionate capital contribution. Expenses associated with these transactions were approximately $1 million. The net proceeds were used to fund a portion of the acquisition of Andrews Petroleum, Inc. and related businesses, to reduce indebtedness and for general partnership purposes. Certain of the funds affiliated with the institutional investors involve related parties. We sold approximately 20% of the common units to investment funds affiliated with Kayne Anderson Capital Advisors, L.P. (KACALP). KAFU Holdings, L.P., which owns 20.3% of our general partner and has a representative on our board of directors, is managed by KACALP.

Distributions

On April 20, 2006, we declared a cash distribution of $0.7075 per unit on our outstanding common units. The distribution is payable on May 15, 2006, to unitholders of record on May 5, 2006, for the period January 1, 2006, through March 31, 2006. The total distribution to be paid is approximately $63 million, with approximately $55 million to be paid to our common unitholders and approximately $1 million and $7 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

On January 24, 2006, we declared a cash distribution of $0.6875 per unit on our outstanding common units. The distribution was paid on February 14, 2006 to unitholders of record on February 3, 2006, for the period October 1, 2005 through December 31, 2005. The total distribution paid was approximately $57 million, with approximately $51 million paid to our common unitholders and $1 million and $6 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Note 8 Long-Term Incentive Plans

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

As of March 31, 2006, there were approximately 2.2 million unvested phantom units with a weighted average grant-date fair value of $31.27 per unit outstanding, substantially all of which were granted in February 2005. In addition, approximately 1.6 million of these Awards include DERs. Approximately 1.5 million of the Awards vest over a six-year period (with performance accelerators), while the remaining awards vest over time only if certain performance conditions are met and are forfeited after seven years if the performance conditions are not met. The DERs vest over time (with performance accelerators) and terminate with the vesting or forfeiture of the related phantom units.

In addition, four of our non-employee directors each have received an LTIP award of 5,000 units. These awards vest annually in 25% increments (1,250 units each). The awards have an automatic re-grant feature such that as they vest, an equivalent amount is granted. For the other two non-employee directors, any director compensation is assigned to the entity that designated them as directors. In those cases, no LTIP award was granted, but in lieu thereof, an equivalent cash payment is made.

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

We recognized expense related to our LTIP of approximately $10 million in the first quarter of 2006 under SFAS 123(R) and $2 million for the first quarter of 2005 under our previous accounting model. During the year ended December 31,2005, approximately 97,000 Awards under our LTIP vested. We paid cash of approximately $1 million in lieu of delivery of common units for approximately 25,000 of the phantom units and issued approximately 47,000 new common units (after netting for taxes of approximately $1 million) in connection with the vesting. In addition, we made DER related payments of approximately $1 million during 2005.

As of March 31, 2006, the weighted average contractual life of our outstanding Awards was approximately five years. Based on the March 31, 2006 fair value measurement, we expect to recognize an additional $62 million of expense over the life of our outstanding Awards related to the remaining unrecognized fair value. This estimate is based on the market price of our limited partner units at the end of the period and actual amounts may differ materially as a result of a change in market price. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	**LTIP Fair Value Amortization**
2006	$ 23.2
2007	17.6
2008	11.2
2009	7.6
2010	2.0
Total	$ 61.6

Note 9 Derivative Instruments and Hedging Activities

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

Summary of Financial Impact

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

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

During the first three months of 2006, our earnings include a net gain of approximately $5 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes (i) a net mark-to-market loss on open positions of approximately $1 million, which is primarily related to the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting and (ii) a net gain of approximately $6 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during the quarter.

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

	March 31, 2006	**December 31, 2005**
Other current assets	$ 70.8	$ 45.7
Other long-term assets	6.8	5.5
Other current liabilities	(94.7)	(72.5)
Other long-term liabilities and deferred credits	(9.2)	(6.5)
Net assets (liabilities)	$ (26.3)	$ (27.8)

The net liability as of March 31, 2006 includes approximately $17 million of unrealized losses recognized in earnings and $9 million of unrealized losses on effective cash flow hedges that are deferred to OCI. The majority of the $17 million of unrealized losses that have been recognized in earnings relate to activities associated with our storage assets. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month to month. We enter into derivative contracts that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. These derivatives do not qualify for hedge accounting because the contracts will not necessarily result in physical delivery.

At March 31, 2006, there was a total unrealized net loss of approximately $14 million deferred to OCI. This included approximately $9 million (referenced above), which predominantly related to unrealized losses on derivatives used to hedge physical inventory in storage that receive hedge accounting, and approximately $5 million relating to terminated interest rate swaps, that are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short derivative positions that will result in losses when prices rise. These hedge losses are offset by an increase in the physical inventory value and will be reclassed into earnings from OCI in the same period that the underlying physical inventory is sold. The total amount of deferred net losses recorded in OCI are 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 OCI at March 31, 2006, a net loss of approximately $11 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified may differ and could vary materially as a result of changes in market conditions.

During the three months ended March 31, 2006, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring.

Note 10 Related Party Transactions

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 pad gas or base gas). We estimate that it will require approximately 7.3 billion cubic feet of pad gas. During the first quarter of 2006, we have arranged to provide the base gas for the storage facility to Pine Prairie at a price not to exceed $8.50 per million cubic feet. In conjunction with this arrangement, we executed hedges on the NYMEX for the relevant delivery periods of 2007, 2008 and 2009. We will receive a fee of approximately $1 million for our services to own and manage the hedge positions and to deliver the natural gas.

Note 11 Commitments and Contingencies

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations (EAR) and must be licensed by the Bureau of Industry and Security (the BIS) of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. We subsequently supplemented the information in response to internal reviews and requests from the BIS. In March 2006, the BIS opened discussion regarding the settlement of any fines and penalties associated with the potential violations of the EAR. In March 2006, we reached agreement in principle with the BIS to settle the matter for an agreed payment of approximately $82,000.

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. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4 million to $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. We have been informed by the U.S. Environmental Protection Agency (EPA) that it has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (DOJ) for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act. We are cooperating with EPA and DOJ in such investigation.

General. We, in the ordinary course of business, are a claimant and /or a defendant in various legal proceedings. We do not believe that the outcome of these legal proceedings, individually and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Other

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

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

Note 12 Operating Segments

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

	Pipeline (in millions)	GMT&S	Total
Three Months Ended March 31, 2006			
Revenues:			
External Customers (includes buy/sell revenues of $45.3, $4,717.7, and $4,763.0, respectively)(1)	$ 246.9	$ 8,388.5	$ 8,635.4
Intersegment(2)	38.0	0.2	38.2
Total revenues of reportable segments	$ 284.9	$ 8,388.7	$ 8,673.6
Segment profit(1)(3)(4)	$ 38.0	$ 55.9	$ 93.9
SFAS 133 impact(1)	$	$ (0.7)	$ (0.7)
Maintenance capital	$ 2.9	$ 1.8	$ 4.7
Three Months Ended March 31, 2005			
Revenues:			
External Customers (includes buy/sell revenues of $33.5, $3,467.0, and $3,500.5, respectively)(1)	$ 212.5	$ 6,426.0	$ 6,638.5
Intersegment(2)	34.7	0.2	34.9
Total revenues of reportable segments	$ 247.2	$ 6,426.2	$ 6,673.4
Segment profit(1)(3)(4)	$ 50.1	$ 16.3	$ 66.4
SFAS 133 impact(1)	$	$ (13.4)	$ (13.4)
Maintenance capital	$ 2.8	$ 1.2	$ 4.0

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

(2) Intersegment sales are conducted at arms length.

(3) GMT&S segment profit includes interest expense on contango inventory purchases of $9 million for the quarter ended March 31, 2006 and $4 million for the quarter ended March 31, 2005 .

(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 March 31 2006	2005
Segment profit	$ 93.9	$ 66.4
Depreciation and amortization	(21.6)	(19.1)
Equity earnings (loss) in PAA/Vulcan Gas Storage, LLC	(0.2)	
Interest expense	(15.3)	(14.6)
Interest income and other, net	0.3	0.1
Income before cumulative effect of change in accounting principle	$ 57.1	$ 32.8

Note 13 Recent Accounting Pronouncements

In December 2004, SFAS 123(R) was issued which amends SFAS No. 123, Accounting for Stock-Based Compensation, and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a cumulative effect of change in accounting principle of approximately $6 million. The cumulative effect adjustment represents a decrease to our Long Term Incentive Plan (LTIP) life-to-date accrued expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair-value based liability as calculated under a SFAS 123(R) methodology. Under the modified prospective transition method, we are not required to adjust our prior period financial statements to reflect a fair value cost methodology for our LTIP awards.

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

We adopted EITF 04-13 on April 1, 2006, which will cause inventory purchases and sales under buy/sell transactions, which were recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statement of operations. We have parenthetically disclosed buy/sell transactions in our consolidated statements of operations in the first quarter 2006. EITF 04-13 will reduce gross revenues and purchases and will not have a material impact on our financial position, net income, or liquidity. The treatment of buy/sell transactions under EITF 04-13 will reduce the relative amount of revenues on our income statement.

Note 14 Subsequent Events

On April 18, 2006, we closed the acquisition of 100% of the equity interests of Andrews Petroleum, Inc. and Lone Star Trucking, Inc. for a total purchase price of approximately $205 million and transaction costs of approximately $8 million.

Also in April 2006, we announced that in three separate transactions we had entered into definitive agreements to acquire certain crude oil pipelines and gathering and transportation assets as well as a natural gas storage facility for aggregate consideration of approximately $130 million, including approximately $36 million of crude oil and natural gas inventory. These transactions included (i) the purchase of an additional 9.5% interest in the Mesa Pipeline System, which is operated by us, (ii) the purchase of crude oil gathering and transportation assets and related contracts in South Louisiana and (iii) the purchase by a subsidiary of PAA/Vulcan Gas Storage, LLC of the Kimball natural gas storage facility, which is located in close proximity to PAA/Vulcan s Bluewater gas storage facility in Michigan. We own a 50% interest in PAA/Vulcan. All of these transactions have closed as of the filing date of this document.

Effective May 1, 2006, we have entered into a five-year agreement with a third party marine towing company to time-charter 22 inland tugboats and 22 tank barges. Annual charter costs will be approximately $17 million, subject to escalation limited by the increase in the Producer Price Index Finished Goods.

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

Introduction

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

- Executive Summary
- Acquisitions and Internal Growth Projects
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Commitments
- Recent Accounting Pronouncements and Change in Accounting Principle
- Critical Accounting Policies and Estimates
- Forward-Looking Statements and Associated Risks

Executive Summary

Overview

We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We refer to liquefied petroleum gas and other natural gas related petroleum products collectively as LPG. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. In addition, through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we are engaged in the development and operation of natural gas storage facilities. Our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P.

We are one of the largest midstream crude oil companies in North America. As of March 31, 2006, we owned approximately 15,000 miles of active crude oil pipelines, approximately 39 million barrels of active terminalling and storage capacity and approximately 500 transport trucks. Currently, we handle an average of over 3 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada.

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

First Quarter 2006 Highlights

During the first quarter of 2006, we reported net income of approximately $63 million and earnings per diluted limited partner unit of $0.71, compared to approximately $33 million and $0.43, respectively, during the first quarter of 2005. Earnings per limited partner unit (both basic and diluted) for the 2006 period was reduced by $0.04 related to the application of Emerging Issues Task Force Issue No. 03-06, Participating Securities and the Two-Class Method under FASB Statement No. 128. See Note 6 to our Consolidated Financial Statements.

Key items during the first quarter of 2006 include:

- Favorable execution of our risk management strategies around our gathering, marketing, terminalling and storage assets in a pronounced contango market with a high level of overall crude oil volatility.

- A net charge of approximately $4 million related to our Long-Term Incentive Plans (LTIP). The net charge included a gain from the reduction of our obligation for outstanding LTIP awards as of January 1, 2006 of $6 million, which was recorded as a cumulative effect of change in accounting principle pursuant to the adoption of SFAS No. 123 (R) (revised 2004), Share-Based Payment (SFAS 123 (R)). Offsetting this gain was an accrual of approximately $10 million pursuant to SFAS 123 (R) related to our outstanding awards at the end of the period.

- An increase in costs associated with increased personnel and related costs, utilities and continued expansion of our operations.

- An increase in planned capital expenditures for expansion projects by $20 million to $250 million of which approximately $45 million was incurred during the quarter.

- The sale of 2.3 million limited partner units for net proceeds of approximately $101 million.

Acquisitions and Internal Growth Projects

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

	Three Months Ended March 31,	
	2006	**2005**
Acquisition capital(1)	$	$ 24.3
Internal growth projects	44.7	38.1
Maintenance capital	4.7	4.0
	$ 49.4	$ 66.4

(1) During 2006 we paid approximately $17 million into escrow for an acquisition that closed in April 2006. The 2005 acquisition capital includes a deposit of approximately $12 million that was paid in 2004.

Subsequent to March 31, 2006, we have completed five acquisitions for aggregate consideration of approximately $360 million. See Note 3 and Note 14 to our Consolidated Financial Statements.

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Internal Growth Projects

During 2005 and 2006, we increased our spending on expansion and internal growth opportunities. Capital expenditures for expansion projects are forecast to be approximately $250 million during calendar 2006 of which approximately $45 million was incurred in the first quarter. These projects include the construction and expansion of pipeline systems and crude oil and LPG storage facilities. We expect revenue contribution from these projects to begin in late 2006 and further increase in 2007. Following are some of the more notable projects to be undertaken in 2006 and the estimated expenditures for the year (in millions):

Projects	**2006**
St. James, Louisiana storage facility	$ 60
Kerrobert tankage and pumps	45
Spraberry System expansion	20
High Prairie truck and rail terminals	18
East Texas/Louisiana tankage	16
Wichita Falls tankage	11
Midale/Regina truck terminal	11
Truck trailers	11
Other	58
Total	$ 250

Results of Operations

Analysis of Operating Segments

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative (G&A) expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our available cash (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period s earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which mitigate the actual decline in the value of our principal fixed assets. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining available cash, consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 11 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Pipeline Operations

As of March 31, 2006, we owned approximately 15,000 miles of active gathering and mainline crude oil pipelines located throughout the United States and Canada (of which approximately 13,000 miles are included in our Pipeline segment). Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee and third party leases of pipeline capacity (collectively referred to as tariff activities), as well as barrel exchanges and buy/sell arrangements (collectively referred to as pipeline margin activities). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount.

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

	Three Months Ended March 31, 2006	2005
Operating Results (in millions)(1)		
Revenues		
Tariff activities	$ 91.0	$ 89.6
Pipeline margin activities(2)	193.9	157.6
Total pipeline operations revenues	284.9	247.2
Costs and Expenses		
Pipeline margin activities purchases(3)	(188.5)	(151.7)
Field operating costs (excluding LTIP charge)	(44.8)	(34.0)
LTIP charge operations	(0.3)	(0.1)
Segment G&A expenses (excluding LTIP charge)(4)	(8.7)	(10.1)
LTIP charge general and administrative(4)	(4.6)	(1.2)
Segment profit	$ 38.0	$ 50.1
Maintenance capital	$ 2.9	$ 2.8
Average Daily Volumes (thousands of barrels per day)(5)		
Tariff activities		
All American	44	54
Basin	314	277
Capline	86	160
Cushing to Broome	70	23
North Dakota/Trenton	82	61
West Texas/New Mexico Area Systems(6)	399	401
Canada	239	268
Other	489	410
Total tariff activities	1,723	1,654
Pipeline margin activities	91	75
Total	1,814	1,729

(1) Revenues and purchases include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $45.3 million and $33.5 million for the quarters ended March 31, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 21,500 and 11,500 barrels per day for the quarters ended March 31, 2006 and 2005, respectively.

(3) Includes purchases associated with buy/sell arrangements of $45.7 million and $31.5 million for the quarters ended March 31, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 21,800 and 10,900 barrels per day for the quarters ended March 31, 2006 and 2005, respectively.

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

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

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

Total revenues for our Pipeline segment were approximately $285 million and $247 million for the three months ended March 31, 2006 and 2005, respectively. The increase in revenues in 2006 is from our margin activities and is primarily related to higher average prices for crude oil sold and transported on our San Joaquin Valley gathering system in 2006 as compared to 2005.

Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales. Accordingly, the increase in revenues in the first quarter of 2006 did not have a corresponding increase in segment profit.

Segment profit for our Pipeline segment decreased approximately $12 million in the first quarter of 2006 as compared to the first quarter of 2005. The decrease in segment profit from 2005 s first quarter is due primarily to an increase in operating expenses associated with an increase in personnel and related costs and utilities. Utilities increased approximately $4 million over the prior year period due to a variety of factors including (i) the net impact of a general increase in electricity rates and power hedges, (ii) an increase in electric consumption and (iii) a true up of prior and current accruals following receipt of final billing information upon expiration of an existing term arrangement with a significant electricity provider. The decrease in segment profit was also impacted by a higher LTIP charge of approximately $4 million in the second quarter of 2006 as compared to the first quarter of 2005. These increased costs were partially offset by lower general and administrative costs. The decrease in general and administrative costs was primarily related to a decrease in the percentage of indirect costs allocated to the Pipeline segment in the 2006 period.

Gathering, Marketing, Terminalling and Storage Operations

As of March 31, 2006, we owned approximately 39 million barrels of active above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. The Cushing Interchange is one of the largest crude oil market hubs in the United States and the designated delivery point for NYMEX crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called terminalling. Approximately 15 million barrels of our 39 million barrels of tankage is used primarily in our GMT&S segment and the balance is used in our Pipeline segment.

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

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Our revenues increased approximately 31% in the first quarter of 2006 compared to the first quarter of 2005 primarily due to higher crude oil prices during the 2006 period. The average NYMEX price for crude oil was $63.46 per barrel for the first three months ended March 31, 2006, as compared to $49.88 per barrel for the same period in 2005.

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 segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. 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 gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period.

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

	Three months ended March 31, 2006	2005
Operating Results (in millions)(1)		
Revenues(2)(3)	$ 8,388.7	$ 6,426.2
Purchases and related costs(4)(5)	(8,277.1)	(6,369.4)
Field operating costs (excluding LTIP charge)	(36.5)	(29.5)
LTIP charge operations	(0.7)	(0.2)
Segment G&A expenses (excluding LTIP charge)(6)	(13.5)	(10.1)
LTIP charge general and administrative	(5.0)	(0.7)
Segment profit(3)	$ 55.9	$ 16.3
SFAS 133 mark-to-market adjustment(3)	$ (0.7)	$ (13.4)
Maintenance capital	$ 1.8	$ 1.2
Segment profit per barrel(7)	$ 0.89	$ 0.26
Average Daily Volumes (thousands of barrels per day)(8)		
Crude oil lease gathering	615	622
LPG sales	84	84

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

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(2) Includes revenues associated with buy/sell arrangements of $4,717.7 million and $3,467.0 million for the three months ended March 31, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 898,000 and 844,000 barrels per day for the three months ended March 31, 2006 and 2005, respectively. The amounts include certain estimates based on management s judgment; such estimates are not expected to have a material impact on the balances.

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

(4) Includes purchases associated with buy/sell arrangements of $4,749.4 million and $3,397.0 million for the three months ended March 31, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 905,000 and 835,000 barrels per day for the three months ended March 31, 2006 and 2005, respectively. The amounts include certain estimates based on management s judgment; such estimates are not expected to have a material impact on the balances.

(5) Purchases and related costs include interest expense on contango inventory purchases of approximately $8.6 million and $3.4 million for the three months ended March 31, 2006 and 2005, respectively.

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

(7) Calculated based on crude oil lease gathered volumes and LPG sales volumes.

(8) 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 for the first three months of 2006 significantly exceeded the comparable 2005 period. The increase was primarily related to very favorable market conditions and successful execution of risk management strategies. During the first quarter of 2006 and 2005, the market has experienced significantly high volatility in prices and market structure of crude oil. The NYMEX benchmark price of crude oil has ranged from $57.55 to $69.00 and from $41.25 to $57.60, respectively, during the first quarter of 2006 and 2005. During the first quarter of 2006, the market was in a contango market structure in which the time spread of prices averaged approximately $1.14 compared to $0.48 in the first quarter of 2005. During this contango market, we have been able to use a portion of our tankage in our terminalling and storage business to capture profits from contango-related strategies. In addition, the volatile market allowed us to utilize hedging activities to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets. Included in these results is contango related interest of approximately $9 million, which is included in Purchase and related costs in the table above.

Partially offsetting these strong results are increased LTIP charges, field operating costs and general and administrative costs. Field operating costs associated with trucking and LPG activities have increased resulting from expanded operations and acquisitions in 2005. In addition, approximately $4 million of costs, primarily related to third party trucking transportation services, are classified as field operating costs in the first quarter of 2006, but are classified as Purchases and Related Costs in the 2005 period. The increase in general and administrative costs are the result of increased personnel and related costs coupled with an increase in the percentage of indirect costs allocated to the GMT&S segment in the 2006 period as the operations have grown.

Segment profit per barrel (calculated based on our lease gathered crude oil and LPG volumes) was $0.89 per barrel for the quarter ended March 31, 2006, compared to $0.26 for the quarter ended March 31, 2005. As discussed above, our current period results were strongly impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as have recently been experienced, and operating results may not be indicative of sustainable performance.

Other Expenses

Depreciation and Amortization

Depreciation and amortization expense was approximately $22 million in the first quarter of 2006 and was approximately $3 million higher compared to the corresponding period in 2005 as a result of the continued expansion in our asset base. Amortization of debt issue costs was approximately $1 million in the first quarter of both 2006 and 2005.

Interest Expense

Interest expense is primarily impacted by:

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

Interest expense increased approximately 5% in the first quarter of 2006 as compared to the first quarter of 2005 primarily due to higher average debt balances during 2006. The higher average debt balance in the first quarter of 2006 was primarily related to the portion of our acquisitions that was not financed with equity, coupled with borrowings related to other capital projects. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our GMT&S segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $9 million and $4 million for quarters ended March 31, 2006 and 2005, respectively.

Outlook

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

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions regarding potential acquisitions by us of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets which, if acquired, could have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass midstream businesses outside of the scope of our current operations. 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.

Longer-Term Outlook. In our annual report on Form 10-K for the year ended December 31, 2005, we identified certain trends, factors and developments, many of which are beyond our control, that may affect our business in the future. We believe that the collective impact of various 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 reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings, which were evident in 2005 and into the first quarter 2006. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among

crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At March 31, 2006, we had working capital of approximately $84 million, approximately $788 million of availability under our committed revolving credit facilities and approximately $77 million of availability under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants.

Cash generated from operations

The primary drivers of cash generated from our operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except in the months that we store inventory because of contango market conditions or in months in which we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period in which we pay for and store the crude oil and the subsequent period in which we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow under our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. 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, the level of LPG inventory stored at period end affects our cash flow from operating activities.

Cash flow used in operating activities was $458 million and $272 million at March 31, 2006 and 2005, respectively, and reflects the purchase and storage of crude oil because of contango market conditions. Both quarters were impacted by the purchase of crude oil for storage, which had a negative impact on cash flows from operating activities when the invoices for the crude oil were paid. The proceeds we received from our credit facilities to pay for the crude oil while stored are shown as financing activities in the cash flow statement. As such, until we deliver the crude oil and receive payment from our customers, operating activities in the cash flow statement will be negatively impacted by this activity. Crude oil stored is hedged against price risk.

Cash provided by equity and debt financing activities

We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $2 billion of debt or equity securities. At March 31, 2006, we had approximately $1.7 billion remaining under this registration statement.

Cash provided by financing activities was approximately $541 million and approximately $343 million at March 31, 2006 and 2005, respectively. Our financing activities primarily relate to funding (i) acquisitions, (ii) internal capital projects and (iii) short-term working capital and hedged inventory borrowings related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings under our credit facilities.

Equity Offerings. *During the three months ended March 31, 2006 and 2005, respectively, we completed equity offerings as summarized in the table below (in millions, except units):*

	Units	Net Proceeds(1)(2)
1st Quarter 2006	2,336,448	$ 101.4
1st Quarter 2005	575,000	$ 22.3

(1) Includes our general partner s proportionate capital contribution and is net of costs associated with the offering.

(2) Certain of these offerings involved related parties. See Note 7 to our Consolidated Financial Statements.

During the three months ended March 31, 2006 and 2005, we had net working capital and short-term letter of credit and hedged inventory borrowings of approximately $498 million and $386 million, respectively. These borrowings were used primarily for purchases of crude oil inventory that was stored. See Cash generated from operations. We also had net repayments under our long-term revolving credit facilities of approximately $18 million in the three months ended March 31, 2005.

Capital Expenditures and Distributions Paid to Unitholders and General Partners

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

Distributions to unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. Total cash distributions made during the periods indicated were as follows (in millions, except per unit amounts):

	Distributions Paid To:				
	Common Unitholders	GP Incentive	2%	Total	Distribution per unit
1st Quarter 2006	$ 50.7	$ 5.6	$ 1.0	$ 57.3	$ 0.6875
1st Quarter 2005	$ 41.2	$ 3.0	$ 0.8	$ 45.0	$ 0.6125

On April 20, 2006, we declared a cash distribution of $0.7075 per unit on our outstanding common units. The distribution is payable on May 15, 2006, to unitholders of record on May 5, 2006, for the period January 1, 2006, through March 31, 2006. The total distribution to be paid is approximately $63 million, with approximately $55 million to be paid to our common unitholders and approximately $1 million and $7 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

Contingencies

See Note 11 to our Consolidated Financial Statements.

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Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts or those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to creditworthy entities.

The following table includes an estimate of the amount and timing of payments due under specified contractual obligations as of March 31, 2006.

	Total (in millions)	2006	2007	2008	2009	2010	2011 and Thereafter
Long-term debt and interest payments (1)	$ 1,370.5	$ 42.8	$ 57.0	$ 57.0	$ 228.7	$ 47.7	$ 937.3
Leases (2)	109.1	14.9	16.7	12.4	11.5	9.6	44.0
Capital expenditure obligations	5.0	5.0					
Other long-term liabilities (3)	40.5	0.8	33.1	1.5	0.5	0.1	4.5
Subtotal	$ 1,525.1	63.5	106.8	70.9	240.7	57.4	985.8
Crude oil and LPG purchases (4) .	3,705.0	1,734.6	566.0	449.9	330.8	231.0	392.7
Total	$ 5,230.1	$ 1,798.1	$ 672.8	$ 520.8	$ 571.5	$ 288.4	$ 1,378.5

(1) Includes debt service payments, interest payments due on our senior notes, interest payments due on the long-term portion of our revolving credit facility currently outstanding and the commitment fee on the portion of our revolving credit facility that is currently not utilized. The interest amount calculated on the long-term portion of our revolving credit facility is based on the assumption that the amount outstanding and the interest rate charged both remain at their current levels.

(2) Leases are primarily for office rent and trucks used in our gathering activities.

(3) Approximately $9 million of non-current liabilities related to SFAS 133 are included in the crude oil and LPG purchases section of this table.

(4) 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 and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At March 31, 2006, we had outstanding letters of credit under our various facilities of approximately $62 million.

Other. Effective May 1, 2006, we have entered into a five-year agreement with a third party marine towing company to time-charter 22 inland tugboats and 22 tank barges. Annual charter costs are projected to be approximately $17 million, subject to escalation limited by the increase in the Producer Price Index Finished Goods.

Recent Accounting Pronouncements and Change in Accounting Principle

See Note 13 to our Consolidated Financial Statements.

Critical Accounting Policies and Estimates

For a discussion regarding our critical accounting policies and estimates, see Item 7 of our 2005 Form 10-K. Also, see Note 8 and Note 13 to our Consolidated Financial Statements.

Forward-Looking Statements and Associated Risks

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

- 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 system;
- declines in volumes shipped on the Basin Pipeline, Capline Pipeline and our other pipelines by us and third party shippers;
- the availability of adequate third party production volumes for transportation and marketing in the areas in which we operate;
- demand for natural gas or various grades of crude oil and resulting changes in pricing conditions or transmission throughput requirements;
- fluctuations in refinery capacity in areas supplied by our transmission lines;
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- our access to capital to fund additional acquisitions and our ability to obtain debt or equity financing on satisfactory terms;
- successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- 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 rates of third party pipelines;
- increased costs or lack of availability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our Long-Term Incentive Plans;

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- the currency exchange rate of the Canadian dollar;
- the impact of crude oil and natural gas price fluctuations;
- shortages or cost increases of power supplies, materials or labor;
- weather interference with business operations or project construction;
- general economic, market or business conditions; and
- other factors and uncertainties inherent in the marketing, transportation, terminalling, gathering and storage of crude oil and liquefied petroleum gas.

Other factors, such as the Risks Related to Our Business discussed in Item 1A. Risk Factors of our most recent annual report on Form 10-K, or 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 Risks included in Item 7A in our 2005 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below.

Commodity Price Risk

All of our open commodity price risk derivatives at March 31, 2006 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below:

	Fair Value	**Effect of 10% Price Decrease**
	(in millions)	
Crude oil:		
Futures contracts	$ (12.7)	$ (16.8)
Swaps and options contracts	$ (30.8)	$ (22.1)
LPG:		
Swaps and options contracts	$ 22.7	$ 14.8

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 time to allow 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 March 31, 2006, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

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

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

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

See Note 11 to our Consolidated Financial Statements.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2005 Annual Report on Form 10-K.

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

None.

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), as amended by Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of April 15, 2004 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.2	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.4	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001)
3.5	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001)
3.6	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005)
3.7	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005)
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.2	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.3	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003)
4.4	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)
4.5	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)

4.6	Class C Common Unit Purchase Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners, L.P., Kayne Anderson MLP Fund, L.L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated March 31, 2004 (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
4.7	Registration Rights Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Kayne Anderson MLP Fund, L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated April 15, 2004 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
4.8	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)
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.

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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: May 5, 2006	By:	/s/ GREG L. ARMSTRONG Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)*
Date: May 5, 2006	By:	/s/ PHIL KRAMER Phil Kramer, *Executive Vice President and Chief Financial Officer (Principal Financial Officer)*