PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 04, 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 June 30, 2006

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

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

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 August 2, 2006, there were outstanding 80,994,178 Common Units.

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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Item 1. UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	June 30, 2006 (unaudited)	**December 31, 2005**
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 7.6	$ 9.6
Trade accounts receivable and other receivables, net	1,917.2	781.0
Inventory	1,155.9	910.3
Other current assets	95.7	104.3
Total current assets	3,176.4	1,805.2
PROPERTY AND EQUIPMENT	2,450.9	2,116.1
Accumulated depreciation	(303.4)	(258.9)
	2,147.5	1,857.2
OTHER ASSETS		
Pipeline linefill in owned assets	200.4	180.2
Inventory in third party assets	80.4	71.5
Investment in PAA/Vulcan Gas Storage, LLC	124.4	113.5
Goodwill	179.6	47.4
Other, net	109.6	45.3
Total assets	$ 6,018.3	$ 4,120.3
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,850.8	$ 1,293.6
Due to related parties	0.2	6.8
Short-term debt	1,188.5	378.4
Other current liabilities	139.9	114.5
Total current liabilities	3,179.4	1,793.3
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	58.4	4.7
Senior notes, net of unamortized discount of $3.3 and $3.0, respectively	1,196.7	947.0
Other long-term liabilities and deferred credits	57.7	44.6
Total liabilities	4,492.2	2,789.6
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS CAPITAL		
Common unitholders (77,273,248 and 73,768,576 units outstanding at June 30, 2006 and December 31, 2005, respectively)	1,485.6	1,294.1
General partner	40.5	36.6
Total partners capital	1,526.1	1,330.7

	$ 6,018.3	$ 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 June 30, 2006 (unaudited)	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006 (unaudited)	Six Months Ended June 30, 2005
REVENUES				
Crude oil and LPG sales (includes buy/sell transactions of $3,706.1 million in the three months ended June 30, 2005 and $4,717.7 million and $7,125.2 million in the six months ended June 30, 2006 and 2005, respectively)	$ 4,635.8	$ 6,919.5	$ 13,007.8	$ 13,337.3
Other gathering, marketing, terminalling and storage revenues	19.2	11.3	35.7	19.5
Pipeline margin activities revenues (includes buy/sell transactions of $40.0 million in the three months ended June 30, 2005 and $45.3 million and $73.6 million in the six months ended June 30, 2006 and 2005, respectively)	173.8	174.9	367.7	332.5
Pipeline tariff activities revenues	63.6	55.0	116.6	109.9
Total revenues	4,892.4	7,160.7	13,527.8	13,799.2
COSTS AND EXPENSES				
Crude oil and LPG purchases and related costs (includes buy/sell transactions of $3,583.6 million in the three months ended June 30, 2005 and $4,749.4 million and $6,984.5 million in the six months ended June 30, 2006 and 2005, respectively)	4,494.6	6,804.2	12,733.7	13,138.9
Pipeline margin activities purchases (includes buy/sell transactions of $37.3 million in the three months ended June 30, 2005 and $45.7 million and $68.8 million in the six months ended June 30, 2006 and 2005, respectively)	165.4	167.5	353.7	319.0
Field operating costs	86.6	67.8	168.9	131.6
General and administrative expenses	27.4	26.1	59.2	48.3
Depreciation and amortization	21.3	19.0	42.9	38.1
Total costs and expenses	4,795.3	7,084.6	13,358.4	13,675.9
OPERATING INCOME	97.1	76.1	169.4	123.3
OTHER INCOME/(EXPENSE)				
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.1		0.9	
Interest expense (net of capitalized interest of $0.9 million and $0.3 million in the three months and $1.7 million and $1.0 million in the six months ended June 30, 2006 and 2005, respectively)	(18.0)	(14.3)	(33.3)	(28.8)
Interest income and other income (expense), net	0.1	0.5	0.4	0.6
Income before cumulative effect of change in accounting principle	80.3	62.3	137.4	95.1
Cumulative effect of change in accounting principle			6.3	
NET INCOME	$ 80.3	$ 62.3	$ 143.7	$ 95.1
NET INCOME-LIMITED PARTNERS	$ 71.4	$ 57.6	$ 128.2	$ 86.9
NET INCOME-GENERAL PARTNER	$ 8.9	$ 4.7	$ 15.5	$ 8.2
BASIC NET INCOME PER LIMITED PARTNER UNIT				
	$ 0.82	$ 0.76	$ 1.47	$ 1.27

Income before cumulative effect of change in accounting principle				
Cumulative effect of change in accounting principle			0.08	
Net income	$ 0.82	$ 0.76	$ 1.55	$ 1.27
DILUTED NET INCOME PER LIMITED PARTNER UNIT				
Income before cumulative effect of change in accounting principle	$ 0.81	$ 0.74	$ 1.45	$ 1.26
Cumulative effect of change in accounting principle			0.08	
Net income	$ 0.81	$ 0.74	$ 1.53	$ 1.26
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	77.0	67.9	75.5	67.7
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	77.8	69.3	76.3	68.7

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)

	Six Months Ended June 30, 2006 (unaudited)	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 143.7	$ 95.1
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	42.9	38.1
Cumulative effect of change in accounting principle	(6.3)	
SFAS 133 mark-to-market adjustment	3.1	26.3
Long-Term Incentive Plan charge	16.8	10.2
Noncash amortization of terminated interest rate hedging instruments	0.8	0.8
(Gain)/loss on foreign currency revaluation	1.8	(0.9)
Net cash paid for terminated interest rate hedging instruments		(0.9)
Equity earnings in PAA/Vulcan Gas Storage, LLC	(0.9)	
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(1,088.8)	(589.4)
Inventory	(214.3)	(351.5)
Accounts payable and other current liabilities	464.5	311.1
Due to related parties	(6.0)	7.7
Net cash used in operating activities	(642.7)	(453.4)
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 3)	(359.8)	(14.5)
Additions to property and equipment	(121.6)	(86.3)
Investment in unconsolidated affiliates	(10.0)	
Cash paid for linefill in assets owned	(4.8)	
Proceeds from sales of assets	3.5	3.4
Net cash used in investing activities	(492.7)	(97.4)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on long-term revolving credit facility	54.6	(143.6)
Net borrowings on working capital revolving credit facility	229.9	71.8
Net borrowings on short-term letter of credit and hedged inventory facility	579.4	575.3
Proceeds from the issuance of senior notes	249.5	149.3
Net proceeds from the issuance of common units (Note 7)	152.4	22.3
Distributions paid to unitholders and general partner (Note 7)	(120.4)	(92.7)
Other financing activities	(4.4)	(5.8)
Net cash provided by financing activities	1,141.0	576.6
Effect of translation adjustment on cash	(7.6)	(0.8)
Net increase (decrease) in cash and cash equivalents	(2.0)	25.0
Cash and cash equivalents, beginning of period	9.6	13.0
Cash and cash equivalents, end of period	$ 7.6	$ 38.0
Cash paid for interest, net of amounts capitalized	$ 49.7	$ 35.8

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units Units (unaudited)	Common Units Amount	General Partner Amount	Total Partners Capital Amount
Balance at December 31, 2005	**73.8**	**$ 1,294.1**	**$ 36.6**	**$ 1,330.7**
Net Income		128.2	15.5	143.7
Distributions		(105.3)	(15.1)	(120.4)
Issuance of common units	3.5	149.3	3.1	152.4
Other comprehensive income		19.3	0.4	19.7
Balance at June 30, 2006	**77.3**	**$ 1,485.6**	**$ 40.5**	**$ 1,526.1**

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30, 2006 (unaudited)	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006 (unaudited)	Six Months Ended June 30, 2005
Net income	$ 80.3	$ 62.3	$ 143.7	$ 95.1
Other comprehensive income/(loss)	19.2	(27.1)	19.7	(96.9)
Comprehensive income/(loss)	$ 99.5	$ 35.2	$ 163.4	$ (1.8)

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	(18.9)		(18.9)
Changes in fair value of outstanding hedge positions	25.0		25.0
Currency translation adjustment		13.6	13.6
Total period activity	6.1	13.6	19.7
Balance at June 30, 2006	$ (10.5)	$ 100.7	$ 90.2

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. On July 20, 2006, we announced an acquisition that, when completed, will represent our initial entry into the refined products transportation business (See Note 3). In addition, through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we are engaged in the development and operation of natural gas storage facilities. Investments in 50% or less owned affiliates, over which we have significant influence, are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with APB 18: *The Equity Method of Accounting for Investments in Common Stock*. An impairment of an equity investment results when factors indicate that the investment s fair value is less than its carrying value and the reduction in value is other than temporary in nature.

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

Note 2 Trade Accounts Receivable

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

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

Balance at December 31, 2005	$ 0.8
Applied to accounts receivable balances	(0.3)
Charged to expense	0.1
Balance at June 30, 2006	$ 0.6

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

Note 3 Acquisitions

We completed five acquisitions during the first half of 2006 for aggregate consideration of approximately $443 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The aggregate purchase price is preliminary pending the resolution of working capital adjustments and the finalization of certain estimated transaction related costs. These acquisitions include (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the Andrews Acquisition), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana and (iii) interests in various crude oil pipeline systems in Canada and the U.S. including a 100% interest in the Bay Marchand-to-Ostrica-to-Alliance Pipeline and various interests in the High Island Pipeline System (payment of approximately $68 million was made on July 3, 2006).

The allocation of the purchase price for these acquisitions is preliminary pending the confirmation of the final purchase price and the completion of valuations for certain of the acquisitions. The preliminary purchase price allocation is as follows (in millions):

Inventory	$ 34.3
Linefill	19.0
Inventory in third party assets	2.3
Property and equipment	207.2
Goodwill (1)	132.2
Intangibles	48.7
Net other assets and liabilities	(0.6)
	$ 443.1

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

Pro Forma Data

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

	Three Months Ended June 30, (1)		**Six Months Ended June 30, (1)**	
	2006	**2005**	**2006**	**2005**
	(unaudited)			
Revenues	$ 5,176.3	$ 7,444.6	$ 14,095.6	$ 14,367.0
Income before cumulative effect of change in accounting principle	$ 88.8	$ 70.8	$ 154.4	$ 112.1
Net income	$ 88.8	$ 70.8	$ 160.7	$ 112.1
Basic income before cumulative effect of change in accounting principle per limited partner unit	$ 0.93	$ 0.88	$ 1.69	$ 1.52
	$ 0.92	$ 0.86	$ 1.67	$ 1.50

Diluted income before cumulative effect of change in accounting principle per limited partner unit				
Basic net income per limited partner unit	$ 0.93	$ 0.88	$ 1.77	$ 1.52
Diluted net income per limited partner unit	$ 0.92	$ 0.86	$ 1.75	$ 1.50

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

In June 2006, we announced that we had entered into a definitive agreement to acquire Pacific Energy Partners, L.P. (Pacific Energy). The total value of the transaction is approximately $2.4 billion, including the assumption of debt and estimated transaction costs, and is expected to close near the end of 2006. Under the terms of the agreements, we will acquire from LB Pacific, LP and its affiliates the general partner interest and incentive distribution rights of Pacific Energy as well as 2.6 million common units and 7.8 million subordinated units for a total of $700 million in cash. In addition, we will acquire the balance of Pacific Energy s equity through a unit-for-unit merger in which each remaining unitholder of Pacific Energy will receive 0.77 newly issued PAA common units for each Pacific Energy common unit. The completion of the transaction remains subject to the approval of the unitholders of PAA and Pacific Energy as well as approvals of certain state utility commissions and the Investment Review Division of Industry Canada.

In July 2006, we completed the acquisition of a 64.35% interest in the Clovelly-to-Meraux (CAM) Pipeline system for a total purchase price of approximately $54 million and we announced that we had entered into a definitive agreement to acquire three refined products pipeline systems from Chevron Pipe Line Company for approximately $65 million. The transaction is expected to close in August 2006, subject to customary closing conditions.

Note 4 Inventory and Linefill

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

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

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

	June 30, 2006			December 31, 2005		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions, except dollars per barrel)					
Inventory						
Crude oil	14,277	$ 931.0	$ 65.21	13,887	$ 755.7	$ 54.42
LPG	5,068	219.1	$ 43.23	3,649	149.0	$ 40.83
Parts and supplies	N/A	5.8	N/A	N/A	5.6	N/A
Inventory subtotal	19,345	1,155.9		17,536	910.3	
Inventory in third-party assets						
Crude oil	1,275	67.1	$ 52.63	1,248	58.6	$ 46.96
LPG	318	13.3	$ 41.82	318	12.9	$ 40.57
Inventory in third-party assets subtotal	1,593	80.4		1,566	71.5	
Linefill						
Crude oil	6,516	199.5	$ 30.62	6,207	179.3	$ 28.89
LPG	27	0.9	$ 33.33	27	0.9	$ 33.33
Linefill subtotal	6,543	200.4		6,234	180.2	
Total	27,481	$ 1,436.7		25,336	$ 1,162.0	

Note 5 Debt

During May 2006, we completed the sale of $250 million aggregate principal amount of 6.70% Senior Notes due 2036. The notes were sold at 99.82% of face value. Interest payments are due on May 15 and November 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are not significant. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

Below is a description of our debt:

	June 30, 2006	**December 31, 2005**
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 5.7% and 4.8% at June 30, 2006 and December 31, 2005, respectively	$ 800.0	$ 219.3
Working capital borrowings, bearing interest at a rate of 5.9% and 5.0% at June 30, 2006 and December 31, 2005, respectively (1)	385.3	155.4
Other	3.2	3.7
Total short-term debt	1,188.5	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 June 30, 2006 and December 31, 2005, respectively	174.5	174.4
7.75% senior notes due October 2012, net of unamortized discount of $0.2 million and $0.2 million at June 30, 2006 and December 31, 2005, respectively	199.8	199.8
5.63% senior notes due December 2013, net of unamortized discount of $0.5 million and $0.5 million at June 30, 2006 and December 31, 2005, respectively	249.5	249.5
5.25% senior notes due June 2015, net of unamortized discount of $0.6 million and $0.7 million at June 30, 2006 and December 31, 2005, respectively	149.4	149.3
5.88% senior notes due August 2016, net of unamortized discount of $1.0 million and $1.0 million at June 30, 2006 and December 31, 2005, respectively	174.0	174.0
6.70% senior notes due May 2036, net of unamortized discount of $0.5 million at June 30, 2006	249.5	
Senior notes, net of unamortized discount (2)	1,196.7	947.0
Long-term debt under senior unsecured revolving credit facility and other	58.4	4.7
Total long-term debt (1)(2)	1,255.1	951.7
Total debt	$ 2,443.6	$ 1,330.1

(1) At June 30, 2006 and December 31, 2005, we have classified $385.3 million and $155.4 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) and International Petroleum Exchange (IPE) margin deposits.

(2) At June 30, 2006, the aggregate fair value of our fixed rate senior notes is estimated to be approximately $1,180.1 million.

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

Also, in July 2006, we entered into a $1.0 billion acquisition bridge facility for the cash portion of the Pacific Energy acquisition. Funding under the bridge facility will occur substantially contemporaneously with closing of the acquisition. The bridge facility has a final maturity date that is the earlier of two years from the date of closing the acquisition or July 2009. The bridge facility has a mandatory reduction of commitments or prepayment requirements following certain public or private debt offerings and asset sales. Borrowings under the bridge facility will bear interest at a rate similar to our senior unsecured revolving credit facility.

During August 2006, we entered into treasury locks with large creditworthy financial institutions. A treasury lock is a financial derivative instrument that enables the company to lock in the U.S. Treasury Note rate, typically in anticipation of a debt issuance. The treasury locks have a notional principal amount of $200 million and an average effective interest rate of 4.97%. The treasury locks mature in November 2006.

Note 6 Earnings Per Limited Partner Unit

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2006	2005	2006	2005
	(in millions, except per unit data)		(in millions, except per unit data)	
Numerator:				
Net income	$ 80.3	$ 62.3	$ 143.7	$ 95.1
Less: General partner s incentive distribution paid	(7.4)	(3.5)	(12.9)	(6.4)
Subtotal	72.9	58.8	130.8	88.7
General partner 2% ownership	(1.5)	(1.2)	(2.6)	(1.8)
Net income available to limited partners	71.4	57.6	128.2	86.9
EITF 03-06 additional general partner s distribution	(8.2)	(6.2)	(11.2)	(0.6)
Net income available to limited partners under EITF 03-06	$ 63.2	$ 51.4	$ 117.0	$ 86.3
Less: Limited partner 98% portion of cumulative effect of change in accounting principle			6.2	
Limted partner net income before cumulative effect of change in accounting principle	$ 63.2	$ 51.4	$ 110.8	$ 86.3
Denominator:				
Basic earnings per limited partner unit (weighted average number of limited partner units outstanding)	77.0	67.9	75.5	67.7
Effect of dilutive securities:				
Weighted average LTIP units outstanding (1)	0.8	1.4	0.8	1.0
Diluted earnings per limited partner unit (weighted average number of limited partner units outstanding)	77.8	69.3	76.3	68.7
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.82	$ 0.76	$ 1.47	$ 1.27
Cumulative effect of change in accounting principle per limited partner unit			0.08	
Basic net income per limited partner unit	$ 0.82	$ 0.76	$ 1.55	$ 1.27
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$ 0.81	$ 0.74	$ 1.45	$ 1.26
Cumulative effect of change in accounting principle per limited partner unit			0.08	
Diluted net income per limited partner unit	$ 0.81	$ 0.74	$ 1.53	$ 1.26

(1) Our LTIP units described in Note 8 are considered dilutive securities except for those units which only vest upon certain performance conditions being met. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in SFAS 128, "Earnings per Share."

Note 7 Partners Capital and Distributions

Direct Placements of Common Units

We completed the following equity offerings of our common units during the six months ended June 30, 2006 and 2005, respectively. In addition, we completed an offering in the third quarter of 2006. See Note 10 Related Party Transactions.

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Period	Units	Gross Unit Price	Proceeds from Sale	GP Contribution	Costs	Net Proceeds
	(in millions, except per unit amounts)					
July/August 2006	3,720,930	$ 43.00	$ 160.0	$ 3.3	$ 0.1	$ 163.2
March/April 2006	3,504,672	$ 42.80	$ 151.0	$ 2.0	$ 0.6	$ 152.4
February 2005	575,000	$ 38.13	$ 21.9	$ 0.5	$ 0.1	$ 22.3

Distributions

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

	Common Units	GP Incentive	2%	Total	Distribution per unit
May 15, 2006	$ 54.6	$ 7.4	$ 1.1	$ 63.1	$ 0.7075
February 14, 2006	50.7	5.6	1.0	57.3	$ 0.6875
2006 total	$ 105.3	$ 13.0	$ 2.1	$ 120.4	
May 13, 2005	$ 43.3	$ 3.5	$ 0.9	$ 47.7	$ 0.6375
February 14, 2005	41.2	3.0	0.8	45.0	$ 0.6125
2005 total	$ 84.5	$ 6.5	$ 1.7	$ 92.7	

On July 14, 2006, we declared a cash distribution of $0.7250 per unit on our outstanding common units. The distribution is payable on August 14, 2006, to unitholders of record on August 4, 2006, for the period April 1, 2006, through June 30, 2006. The total distribution to be paid is approximately $69 million, with approximately $59 million to be paid to our common unitholders and approximately $1 million and $9 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

Note 8 Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan and the 2005 Long-Term Incentive Plan, collectively referred to as 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 June 30, 2006, there were approximately 2.2 million unvested phantom units outstanding with a weighted average grant-date fair value of approximately $32.22 per unit. In addition, approximately 1.6 million of these Awards include DERs. Approximately 1.5 million of the Awards vest over a six-year period (with performance accelerators), while the remaining awards vest over time only if certain performance conditions are met and are forfeited after six years if the performance conditions are not met. The DERs vest over time (with performance accelerators) and terminate with the vesting or forfeiture of the related phantom units.

In addition, four of our six 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), Share Based Payment (SFAS 123(R)) on January 1, 2006 (See Note 13 for a discussion of recent accounting pronouncements). Under SFAS 123(R) the fair value of the Awards, which are subject to liability classification, is calculated based on the market price of our units at the balance sheet date adjusted for (i) the present value of any distributions that are probable of occurring on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is then expensed over the period the Awards are earned. In addition, we recognize compensation expense for DER payments in the period the payment is earned.

We recognized expense related to our LTIP of approximately $6 and $8 million during the second quarter, and $17 million and $10 million during the first six months of 2006 and 2005, respectively. Additionally, we have an accrued liability of approximately $35 million associated with our LTIP as of June 30, 2006.

As of June 30, 2006, the weighted average contractual life of our outstanding Awards was approximately five years. Based on the June 30, 2006 fair value measurement, we expect to recognize an additional $56 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 (1)	$ 13.5
2007	19.1
2008	12.9
2009	8.4
2010	2.3
Total	$ 56.2

(1) Includes LTIP fair value amortization for the remaining six months of 2006.

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, 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. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of the hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil, LPG and natural gas as well as with respect to expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, 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 half of 2006, our earnings include a net loss of approximately $8 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 loss includes:

a) A net mark-to-market loss of approximately $3 million (a $1 million and $2 million loss in each of the the first and second quarters of 2006, respectively), which is primarily comprised of the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting and

b) A net loss of approximately $5 million related to settled derivatives taken to earnings during the period. The majority of this net loss is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during the first half of 2006.

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 June 30, 2006 and December 31, 2005, respectively (in millions):

	June 30, 2006	**December 31, 2005**
Other current assets	$ 56.1	$ 45.7
Other long-term assets	8.3	5.5
Other current liabilities	(80.4)	(72.5)
Other long-term liabilities and deferred credits	(9.6)	(6.5)
Net asset (liability)	$ (25.6)	$ (27.8)

The net liability as of June 30, 2006 includes approximately $20 million of unrealized losses recognized in earnings and $6 million of unrealized losses on effective cash flow hedges that are deferred to OCI. The majority of the $20 million of unrealized losses that have been recognized in earnings relate to activities associated with our storage assets. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month to month. We enter into derivative contracts, including futures and options, that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. These derivatives do not qualify for hedge accounting because the contracts will not necessarily result in physical delivery.

At June 30, 2006, there was a total unrealized net loss of approximately $10 million deferred to OCI. This included approximately $6 million (referenced above), which predominantly related to unrealized losses on derivatives used to hedge physical inventory in storage that receive hedge accounting, and approximately $4 million relating to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short 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 June 30, 2006, a net loss of approximately $6 million will be reclassified into earnings in the next twelve months and the remaining net loss at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2009 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

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

Note 10 Related Party Transactions

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

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

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

Note 11 Commitments and Contingencies

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 June 2006, we settled this matter with the 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. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency (EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the

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course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4.5 million to $5.0 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. We have been informed by EPA that it has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act. Our assessment is that it is probable we will pay penalties related to the two releases. We have accrued the estimated loss contingency, which is included in the estimated aggregate costs set forth above. It is reasonably possible that the loss contingency may exceed our estimate with respect to penalties assessed by EPA; however, we have no indication from EPA or the Department of Justice of what penalties might be sought. As a result, we are unable to estimate the range of a reasonably possible loss contingency in excess of our accrual.

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

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

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

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

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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 tables reflect certain financial data for each segment for the periods indicated:

	Pipeline	GMT&S (in millions)	Total
Three Months Ended June 30, 2006			
Revenues:			
External Customers (1)	$ 237.3	$ 4,655.1	$ 4,892.4
Intersegment (2)	37.6	0.2	37.8
Total revenues of reportable segments	$ 274.9	$ 4,655.3	$ 4,930.2
Segment profit (3)(4)(5)	$ 53.1	$ 65.3	$ 118.4
SFAS 133 impact (3)	$	$ (2.4)	$ (2.4)
Maintenance capital	$ 3.3	$ 1.1	$ 4.4
Three Months Ended June 30, 2005			
Revenues:			
External Customers (includes buy/sell revenues of $40.0, $3,706.1, and $3,746.1, for Pipeline, GMT&S and Total, respectively)	$ 229.9	$ 6,930.8	$ 7,160.7
Intersegment (2)	30.6	0.2	30.8
Total revenues of reportable segments	$ 260.5	$ 6,931.0	$ 7,191.5
Segment profit (3)(4)(5)	$ 41.4	$ 53.7	$ 95.1
SFAS 133 impact (3)	$	$ (12.9)	$ (12.9)
Maintenance capital	$ 2.5	$ 1.5	$ 4.0

	Pipeline	GMT&S (in millions)	Total
Six Months Ended June 30, 2006			
Revenues:			
External Customers (includes buy/sell revenues of $45.3, $4,717.7, and $4,763.0, for Pipeline, GMT&S and Total, respectively)	$ 484.3	$ 13,043.5	$ 13,527.8
Intersegment (2)	75.6	0.4	76.0
Total revenues of reportable segments	$ 559.9	$ 13,043.9	$ 13,603.8
Segment profit (3)(4)(5)	$ 91.1	$ 121.2	$ 212.3
SFAS 133 impact (3)	$	$ (3.1)	$ (3.1)
Maintenance capital	$ 6.2	$ 2.9	$ 9.1
Six Months Ended June 30, 2005			
Revenues:			
External Customers (includes buy/sell revenues of $73.6, $7,125.2, and $7,198.8, for Pipeline, GMT&S and Total, respectively)	$ 442.4	$ 13,356.8	$ 13,799.2
Intersegment (2)	65.3	0.4	65.7
Total revenues of reportable segments	$ 507.7	$ 13,357.2	$ 13,864.9
Segment profit (3)(4)(5)	$ 91.4	$ 70.0	$ 161.4
SFAS 133 impact (3)	$	$ (26.3)	$ (26.3)
Maintenance capital	$ 5.3	$ 2.7	$ 8.0

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

(2) Intersegment sales are conducted at arms length.

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

(4) GMT&S segment profit includes interest expense on contango purchases of $13.3 million and $5.8 million for the quarter and $21.9 million and $9.2 million for the six months ended June 30, 2006 and 2005, respectively.

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

	For the three months ended June 30		For the six months ended June 30	
	2006	2005	2006	2005
Segment profit	$ 118.4	$ 95.1	$ 212.3	$ 161.4
Depreciation and amortization	(21.3)	(19.0)	(42.9)	(38.1)
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.1		0.9	
Interest expense	(18.0)	(14.3)	(33.3)	(28.8)
Interest income and other income (expense), net	0.1	0.5	0.4	0.6
Income before cumulative effect of change in accounting principle	$ 80.3	$ 62.3	$ 137.4	$ 95.1

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Note 13 Recent Accounting Pronouncements

In December 2004, SFAS 123(R) was issued, which amends SFAS No. 123, Accounting for Stock-Based Compensation, and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. Following our general partner s adoption of Emerging Issues Task Force Issue No. 04-05, Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights, we are part of the same consolidated group and thus SFAS 123 (R) will be applicable to our general partner s long-term incentive plan. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a cumulative effect of change in accounting principle of approximately $6 million. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair-value based liability as calculated under a SFAS 123(R) methodology. 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 became effective in reporting periods beginning after March 15, 2006.

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

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

Introduction

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

Highlights Second Quarter and First Half of 2006

Net income for the second quarter of 2006 was approximately $80 million, or $0.81 per diluted limited partner unit, which is an increase of 29% and 9%, respectively, over net income of $62 million, or $0.74 per diluted limited partner unit for the second quarter of 2005. For the first six months of 2006, net income was approximately $144 million, or $1.53 per diluted limited partner unit, representing increases of 51% and 21%, respectively, over net income of approximately $95 million, or $1.26 per limited partner unit, for the first six months of 2005. Earnings per limited partner unit (both basic and diluted) was reduced by $0.11 and $0.09 for the three months ended and $0.15 and $0.01 for the six months ended June 30, 2006 and 2005, respectively, 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 impacting the first half of 2006 include:

- The completion of five acquisitions for aggregate consideration of $443 million.

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

- Increased volumes and related tariff revenues on our pipeline systems.

- The inclusion in the second quarter and first half of 2006 of an aggregate charge of approximately $6 million and $17 million, respectively, related to both of our Long-Term Incentive Plans.

- An increase in costs primarily associated with our continued growth from internal growth projects and acquisitions.

- An increase in 2006 planned capital expenditures for internal growth projects by $25 million to $275 million, of which approximately $104 million has been incurred.

- An issuance of $250 million senior notes due 2036 for net proceeds of approximately $249.5 million.

- The sale of 3.5 million limited partner units for net proceeds of approximately $152 million in March and April 2006.

Acquisitions and Internal Growth Projects

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

	Six Months Ended June 30,	
	2006	**2005**
Acquisition capital (1)	$ 443.1	$ 24.3
Investment in PAA/Vulcan Gas Storage, LLC	10.0	
Internal growth projects	103.5	72.7
Maintenance capital	9.1	8.1
	565.7	105.1

(1) The 2006 acquisiton capital includes approximately $67 million that was paid on July 3, 2006 for an acquisition that closed on June 30, 2006. The 2005 acquisition capital includes a deposit of approximately $12 million that was paid in 2004.

Acquisitions

We completed five transactions during the first half of 2006 for aggregate consideration of approximately $443 million. In addition, in June 2006, we entered into a definitive agreement to purchase Pacific Energy for approximately $2.4 billion, including the assumption of debt and estimated transaction costs. The transaction is expected to close near the end of 2006. In July 2006, we entered into a definitive agreement to acquire three refined products pipeline systems from Chevron Pipe Line Company for approximately $65 million. This transaction is expected to close in August 2006. Also, in July 2006, we completed the acquisition of a 64.35% interest in the CAM Pipeline system for a total purchase price of approximately $54 million. See Note 3 to our Consolidated Financial Statements.

Internal Growth Projects

Capital expenditures for expansion projects are forecast to be approximately $275 million during calendar 2006 of which approximately $104 million was incurred in the first six months. 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 2006 and achieve full run-rate by mid 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	$ 65
Kerrobert tankage	32
Spraberry System expansion	19
East Texas/Louisiana tankage	17
High Prairie rail terminals	13
Midale/Regina truck terminal	13
Wichita Falls tankage	10
Truck trailers	9
Basin connection - Oklahoma	9
Mobile/Ten Mile tankage and metering	8
Other Projects	80
Total	$ 275

Results of Operations

Analysis of Operating Segments

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

Pipeline Operations

As of June 30, 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 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 June 30, 2006	2005	Six Months Ended June 30, 2006	2005
	(in millions)		(in millions)	
Operating Results (1)				
Revenues				
Tariff activities	$ 101.1	$ 85.6	$ 192.1	$ 175.3
Pipeline margin activities (2)	173.8	174.9	367.8	332.4
Total pipeline operations revenues	274.9	260.5	559.9	507.7
Costs and Expenses				
Pipeline margin activities purchases (3)	(165.6)	(167.8)	(354.2)	(319.5)
Field operating costs (excluding LTIP charge)	(45.2)	(37.7)	(89.9)	(71.7)
LTIP charge - operations	(0.2)	(0.3)	(0.6)	(0.4)
Segment G&A expenses (excluding LTIP charge)	(8.5)	(9.2)	(17.3)	(19.4)
LTIP charge - general and administrative	(2.3)	(4.1)	(6.8)	(5.3)
Segment profit	$ 53.1	$ 41.4	$ 91.1	$ 91.4
Maintenance capital	$ 3.3	$ 2.5	$ 6.2	$ 5.3
Average Daily Volumes (thousands of barrels per day)				
Tariff activities				
All American	53	50	48	52
Basin	330	283	322	280
Capline	178	143	132	152
Cushing to Broome	79	84	75	54
North Dakota/Trenton	87	73	85	67
West Texas/New Mexico Area Systems	478	435	460	418
Canada	253	248	246	258
Other	458	421	452	415
Total tariff activities	1,916	1,737	1,820	1,696
Pipeline margin activities	85	67	88	71
Total	2,001	1,804	1,908	1,767

(1) Revenues and purchases include intersegment amounts

(2) Includes revenues associated with buy/sell arrangements of $40 million for the quarter ended June 30, 2005 and $45.3 million and $73.6 million for the six months ended June 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 12,800 barrels per day for the quarter ended June 30, 2005 and 21,500 and 12,100 barrels per day for the six months ended June 30, 2006 and 2005, respectively.

(3) Includes purchases associated with buy/sell arrangements of $37.3 million for the quarter ended June 30, 2005 and $45.7 million and $68.8 million for the six months ended June 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 12,800 barrels per day for the quarter ended June 30, 2005 and 21,800 and 12,100 barrels per day for the six months ended June 30, 2006 and 2005, respectively.

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

- Increased volumes and related tariff revenues The increase in tariff revenues has occurred primarily in the second quarter of 2006 and resulted from (i) higher volumes primarily from mult-year contracts on our Basin and Capline systems coupled with (ii) higher volumes on various other systems and (iii) increased revenues from loss allowance oil of approximately $5 million and $7 million in the second quarter and first half of 2006, respectively. As is common in the industry, our crude oil tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. The loss allowance factor averages approximately 0.2%, by volume. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Gains or losses on sales of allowance oil barrels are also included in tariff revenues. Increased volumes and higher crude oil prices during the second quarter and first half of 2006 as compared to the second quarter and first half of 2005 have resulted in increased revenues related to loss allowance oil. The NYMEX averages were $70.59 and $67.13 for the second quarter and first half of 2006, respectively, as compared to $53.23 and $51.60 for the second quarter and first half of 2005, respectively.

- Field operating and general and administrative costs Field operating costs have increased for most categories of costs for the second quarter and first half of 2006 as we have continued to grow primarily through expansion projects over the last year. The most significant cost increases have been related to (i) payroll and benefits and (ii) utilities. Utilities increased approximately $7 million for the first six months of 2006 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 electricity 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. 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.

Total revenues for our Pipeline segment increased for both the three and six month periods ended June 30, 2006 as compared to the same periods ended June 30, 2005 due to a combination of the following factors

- An increase in tariff activities volumes due to new multi-year contracts with shippers as well as an increase in tariff activities revenues due to loss allowance oil (see discussion above);

- An increase in pipeline margin activities revenues for the six month period due to an increase in the average NYMEX price for crude oil 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; and

- A decrease in our second quarter 2006 pipeline margin activities revenues due to the adoption of EITF 04-13 which was equally offset with pipeline margin activities purchases and does not impact segment profit (see Note 13 to our Consolidated Financial Statements).

Gathering, Marketing, Terminalling and Storage Operations

As of June 30, 2006, we owned approximately 39 million barrels of active above-ground crude oil terminalling and storage facilities, approximately 15 million barrels of which relate to our gathering, marketing, terminalling and storage segment (the remaining approximately 24 million barrels of tankage are associated with our pipeline transportation operations within our pipeline segment). These facilities include a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and is the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. In 2005, we began construction of a 3.2 million barrel crude oil terminal at the St. James crude oil interchange in Louisiana, which is also a major crude oil trading location. Our St. James facility is expected to

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be operational in mid-2007.

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

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

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

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

We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in our GMT&S segment volumes, which are comprised of (i) lease gathered volumes, (ii) LPG sales and third party processing volumes and (iii) waterborne foreign crude imported. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business, our storage assets and our hedging 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) GMT&S segment volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our GMT&S segment for the comparable periods indicated:

	Three months ended June 30, 2006	2005	Six months ended June 30, 2006	2005
	(dollars in millions, except per barrel amounts)			
Operating Results (1)				
Revenues (2) (3)	$ 4,655.3	$ 6,931.0	$ 13,043.9	$ 13,357.2
Purchases and related costs (4) (5)	(4,532.2)	(6,834.7)	(12,809.2)	(13,204.1)
Field operating costs (excluding LTIP charge)	(40.8)	(29.1)	(77.3)	(58.6)
LTIP charge - operations	(0.4)	(0.7)	(1.1)	(0.9)
Segment G&A expenses (excluding LTIP charge) (6)	(13.3)	(9.9)	(26.8)	(20.0)
LTIP charge - general and administrative	(3.3)	(2.9)	(8.3)	(3.6)
Segment profit (3)	$ 65.3	$ 53.7	$ 121.2	$ 70.0
SFAS 133 mark-to-market adjustment (3)	$ (2.4)	$ (12.9)	$ (3.1)	$ (26.3)
Maintenance capital	$ 1.1	$ 1.5	$ 2.9	$ 2.7
Segment profit per barrel (7)	$ 0.97	$ 0.84	$ 0.89	$ 1.04
Average Daily Volumes (thousands of barrels per day) (8)				
Crude oil lease gathered	652	628	637	625
LPG sales and third party processing	47	26	66	55
Waterborne foreign crude imported	43	52	50	57
GMT&S activities total	742	706	753	737

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

(2) Includes revenues associated with buy/sell arrangements of $3,706.1 million for the quarter ended June 30, 2005 and $4,717.7 million and $7,125.2 million for the six months ended June 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 825,000 barrels per day for the quarter ended June 30, 2005 and 898,000 and 829,000 barrels per day for the six months ended June 30, 2006 and 2005, respectively.

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

(4) Includes purchases associated with buy/sell arrangements of $3,583.6 million for the quarter ended June 30, 2005 and $4,749.4 million and $6,984.5 million for the six months ended June 30, 2006 and 2005, respectively. Volumes associated with these arrangements were approximately 825,000 barrels per day for the quarter ended June 30, 2005 and 905,000 and 829,000 barrels per day for the six months ended June 30, 2006 and 2005, respectively.

(5) Purchases and related costs include interest expense on contango and other hedged inventory purchases of approximately $13.3 million and $5.8 million for the quarters ended and $21.9 million and $9.2 million for the six months ended June 30, 2006 and 2005, respectively.

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

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

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

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

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

- Favorable market conditions and execution of our risk management strategies During the first six months of 2006 and 2005, the crude oil market has experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil has ranged from $57.55 to $73.93 during the first half of 2006. The volatile market allowed us to utilize hedging activities to optimize and enhance the margins of both our gathering and marketing and our terminalling and storage assets. Although the market was in contango for most of the first six months of 2006 and the time spread of prices averaged approximately $1.11 versus $0.86 for the same period in 2005, this increase in spreads was offset by an increase in the cost to carry the inventory that was not only impacted by the increase in LIBOR rates but also by the increase in NYMEX prices. Included in our GMT&S segment profit is contango and other hedged inventory related interest expense of approximately $13.3 and $21.9 million for the second quarter of 2006 and the first half of 2006, respectively, which is included in Purchases and related costs in the table above.

- SFAS 133 mark-to-market The second quarter and first six months of 2006 include SFAS 133 mark-to-market losses of $2.4 million and $3.1 million, respectively, compared to losses of $12.9 million and $26.3 million for the comparable 2005 periods.

- Field operating and general and administrative costs Partially offsetting these factors are increased field operating costs and general and administrative costs. Costs associated with trucking and LPG activities have increased as a result of expanded operations and acquisitions in 2006. In addition, the second quarter of 2006 and the six months ended June 30, 2006 include approximately $4 million and $8 million, respectively, of costs that are primarily related to third-party trucking transportation services. Comparable costs were classified as Purchases and related costs in the 2005 period. The increase in general and administrative costs is primarily the result of 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 GMT&S volumes included in the table above) was $0.97 for the quarter ended June 30, 2006, compared to $0.84 for the quarter ended June 30, 2005. Segment profit per barrel was $0.89 for the first half of 2006, compared to $1.04 for the first half of 2005. As discussed above, our current period results were strongly impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as have recently been experienced,