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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported)—January 1, 2004

Plains All American Pipeline, L.P.

(Name of Registrant as specified in its charter)

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

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

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

Item 5. Other Items

During the second quarter of 2004, Plains All American Pipeline, L.P. changed its method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, historically we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, will be included in "Inventory" (a current asset) and included in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we will reclassify the long-term portion of linefill in third party assets (i.e. the portion of operating inventory valued at average cost not expected to be used within the next twelve months) out of "Inventory" (a current asset) and into "Inventory in Third Party Assets" (a long-term asset), which will be reflected as a separate line item within other assets on the consolidated balance sheet. This change in accounting principle is effective January 1, 2004 and is reflected in the consolidated statement of operations for the three months ended March 31, 2004 and the consolidated balance sheet as of March 31, 2004 included as an exhibit to this report. In conjunction with this change in accounting principle, we will classify cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification as cash flows from operating activities.

Item 7. Financial Statements and Exhibits

(c) Exhibits

18.1 Letter re: change in accounting principle

99.1 Plains All American Pipeline, L.P. Consolidated Financial Statements (Unaudited) as of March 31, 2004 and December 31, 2003 and for the Three Months Ended March 31, 2004 and 2003.

SIGNATURES

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

	PLAINS ALL AMERICAN PIPELINE, L.P.	
Date: July 21, 2004	By:	Plains AAP, L.P., its general partner
	By:	Plains All American GP LLC, its general partner
	By:	/s/ TINA L. VAL
		Name: Tina L. Val Title: Vice President—Accounting and Chief Accounting Officer

Index to Exhibits

18.1	Letter re: change in accounting principle
99.1	Plains All American Pipeline, L.P. Consolidated Financial Statements (Unaudited) as of March 31, 2004 and December 31, 2003 and for the Three Months Ended March 31, 2004 and 2003.

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Exhibit 18.1

July 21, 2004

Board of Directors
Plains All American GP LLC, the general partner of
Plains AAP, L.P., the general partner of
Plains All American Pipeline, L.P.
333 Clay Street, Suite 1600
Houston, Texas 77002-4101

Dear Directors:

We are providing this letter to you for inclusion as an exhibit to the Plains All American Pipeline, L.P. ("PAA") Form 8-K filing which includes the unaudited consolidated balance sheet as of March 31, 2004 and the unaudited consolidated statements of operations, of cash flows and of comprehensive income for the three months ended March 31, 2004 and 2003 and the unaudited consolidated statement of partners' capital and of changes in accumulated other comprehensive income for the three months ended March 31, 2004 pursuant to Item 601 of Regulation S-K.

We have been provided a copy of PAA's unaudited consolidated financial statements for the three month periods ended March 31, 2004 and 2003 included in PAA's Form 8-K. Note 1 therein describes a change in accounting principle from recording pipeline linefill held in pipelines not owned by PAA ("linefill in third party assets") as a separate asset to including linefill in third party assets in operating inventory. It should be understood that the preferability of one acceptable method of accounting over another for linefill in third party assets has not been addressed in any authoritative accounting literature, and in expressing our concurrence below we have relied on management's determination that this change in accounting principle is preferable. Based on our reading of management's stated reasons and justification for this change in accounting principle in Note 1 to the unaudited consolidated financial statements for the three month periods ended March 31, 2004 and 2003 included in PAA's Form 8-K, and our discussions with management as to their judgment about the relevant business planning factors relating to the change, we concur with management that such change represents, in the Company's circumstances, the adoption of a preferable accounting principle in conformity with Accounting Principles Board Opinion No. 20.

We have not audited any financial statements of the Company as of any date or for any period subsequent to December 31, 2003. Accordingly, our comments are subject to change upon completion of an audit of the consolidated financial statements covering the period of the accounting change.

Very truly yours,

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	March 31, 2004	December 31, 2003
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 2,037	$ 4,137
Trade accounts receivable, net	554,405	590,645
Inventory	72,170	105,967
Other current assets	23,471	32,225
Total current assets	652,083	732,974
PROPERTY AND EQUIPMENT	1,442,241	1,272,634
Accumulated depreciation	(133,529)	(121,595)
	1,308,712	1,151,039
OTHER ASSETS		
Pipeline linefill	92,914	95,928
Inventory in third party assets	28,911	26,725
Other, net	79,339	88,965
Total assets	$ 2,161,959	$ 2,095,631
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 645,322	$ 603,460
Due to related parties	26,539	26,981
Short-term debt	14,689	127,259
Other current liabilities	39,726	44,219
Total current liabilities	726,276	801,919
LONG-TERM LIABILITIES		
Long-term debt under credit facilities	238,737	70,000
Senior notes, net of unamortized discount of $983 and $1,009, respectively	449,017	448,991
Other long-term liabilities and deferred credits	14,865	27,994
Total liabilities	1,428,895	1,348,904
COMMITMENTS AND CONTINGENCIES (NOTE 9)		
PARTNERS' CAPITAL		
Common unitholders (57,162,638 and 49,502,556 units outstanding at March 31, 2004, and December 31, 2003, respectively)	691,695	744,073
Class B common unitholder (1,307,190 units outstanding at each date)	17,670	18,046
Subordinated unitholders (no units and 7,522,214 units outstanding at March 31, 2004, and December 31, 2003, respectively)	—	(39,913)
General partner	23,699	24,521
Total partners' capital	733,064	746,727
Total liabilities and partners' capital	$ 2,161,959	$ 2,095,631

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 thousands, except per unit data)

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(unaudited)	
REVENUES		
Crude oil and LPG sales	$ 3,615,984	$ 3,115,287
Other gathering, marketing, terminalling and storage revenues	15,119	7,349
Pipeline margin activities revenues	142,335	135,171
Pipeline tariff activities revenues	31,206	24,101
Total revenues	3,804,644	3,281,908
COSTS AND EXPENSES		
Crude oil and LPG purchases and related costs	3,557,071	3,060,711
Pipeline margin activities purchases	136,434	130,530
Field operating expenses (excluding LTIP charge)	37,816	33,115
LTIP charge—field operating expenses	567	—
General and administrative expenses (excluding LTIP charge)	15,478	13,072
LTIP charge—general and administrative	3,661	—
Depreciation and amortization	13,120	10,871
Total costs and expenses	3,764,147	3,248,299
OPERATING INCOME	40,497	33,609
OTHER INCOME/(EXPENSE)		
Interest expense (net of $178 and $52 capitalized, respectively)	(9,532)	(9,154)
Interest and other income (expense), net	41	(104)
Income before cumulative effect of accounting change	31,006	24,351
Cumulative effect of accounting change	(3,130)	—
NET INCOME	$ 27,876	$ 24,351
NET INCOME-LIMITED PARTNERS	$ 25,707	$ 22,876
NET INCOME-GENERAL PARTNER	$ 2,169	$ 1,475
BASIC AND DILUTED NET INCOME PER LIMITED PARTNER UNIT		
Income before cumulative effect of accounting change	$ 0.49	$ 0.46
Cumulative effect of accounting change	$ (0.05)	$ —
Net income	$ 0.44	$ 0.46
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	58,414	50,166
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	59,017	50,166

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 thousands)

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
	(unaudited)	(unaudited)
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 27,876	$ 24,351
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	13,120	10,871
Cumulative effect of accounting change	3,130	—
Change in derivative fair value	(7,498)	(930)
Noncash portion of LTIP charge	4,228	—
Noncash amortization of terminated interest rate swap	357	—
Changes in assets and liabilities, net of acquisitions:		
Accounts receivable and other	35,030	9,539
Inventory	32,473	40,114
Accounts payable and other current liabilities	24,711	16,882
Due to related parties	(446)	4,278
Net cash provided by operating activities	132,981	105,105
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 2)	(143,228)	(44,373)
Additions to property and equipment	(13,325)	(15,077)
Cash paid for linefill on assets owned	—	(13,712)
Proceeds from sales of assets	650	543
Net cash used in investing activities	(155,903)	(72,619)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net long-term borrowings on revolving credit facility	168,720	18,788
Net repayments on short-term letter of credit and hedged inventory facility	(101,370)	(85,326)
Net short-term repayments on revolving credit facility	(11,200)	—
Cash paid in connection with financing arrangements	—	(54)
Net proceeds from the issuance of common units	88	63,895
Distributions paid to unitholders and general partner	(35,174)	(28,199)
Net cash provided by (used in) financing activities	21,064	(30,896)
Effect of translation adjustment on cash	(242)	186
Net increase (decrease) in cash and cash equivalents	(2,100)	1,776
Cash and cash equivalents, beginning of period	4,137	3,501
Cash and cash equivalents, end of period	$ 2,037	$ 5,277
Cash paid for interest, net of amounts capitalized	$ 2,150	$ 5,846

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 thousands)

	Common Unitholders		Class B Common Unitholder		Subordinated Unitholders		General Partner Amount	Total Partners' Capital Amount
	Units	Amounts	Units	Amounts	Units	Amounts		
	(unaudited)							
Balance at December 31, 2003	49,502	$ 744,073	1,307	$ 18,046	7,523	$ (39,913)	$ 24,521	$ 746,727
Issuance of common units	138	4,361	—	—	—	—	88	4,449
Distributions	—	(27,893)	—	(735)	—	(4,231)	(2,315)	(35,174)
Other comprehensive income	—	(8,992)	—	(217)	—	(841)	(764)	(10,814)
Net income	—	23,687	—	576	—	1,444	2,169	27,876
Conversion of subordinated units	7,523	(43,541)	—	—	(7,523)	43,541	—	—
Balance at March 31, 2004	57,163	$ 691,695	1,307	$ 17,670	—	$ —	$ 23,699	$ 733,064

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 AND CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in thousands)

Statements of Comprehensive Income

	Three Months Ended March 31,	
	2004	2003
	(unaudited)	
Net income	$ 27,876	$ 24,351
Other comprehensive income	(10,814)	19,923
Comprehensive income	$ 17,062	$ 44,274

Statement of Changes in Accumulated Other Comprehensive Income

	Net Deferred Gain (Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2003	$ (7,692)	$ 39,861	$ 32,169
Current period activity			
Reclassification adjustments for settled contracts	(2,124)	—	(2,124)
Changes in fair value of outstanding hedge positions	(5,231)	—	(5,231)
Currency translation adjustment	—	(3,459)	(3,459)
Total period activity	(7,355)	(3,459)	(10,814)
Balance at March 31, 2004	$ (15,047)	$ 36,402	$ 21,355

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

Note 1—Organization and Accounting Policies

Plains All American Pipeline, L.P. is a publicly traded Delaware limited partnership (the "Partnership") 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 petroleum products. We refer to liquefied petroleum gas and other petroleum products collectively as "LPG." Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. (formerly known as All American Pipeline, L.P.) and Plains Marketing Canada, L.P., and are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan.

The accompanying consolidated financial statements and related notes present (i) our consolidated financial position as of March 31, 2004, and December 31, 2003, (ii) the results of our consolidated operations for the three months ended March 31, 2004 and 2003, (iii) our consolidated cash flows for the three months ended March 31, 2004 and 2003, (iv) our consolidated changes in partners' capital for the three months ended March 31, 2004, (v) our consolidated comprehensive income for the three months ended March 31, 2004 and 2003, and (vi) our changes in consolidated accumulated other comprehensive income for the three months ended March 31, 2004. 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 period amounts to conform to current period presentation. The results of operations for the three months ended March 31, 2004 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 2003 Annual Report on Form 10-K.

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, historically we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, will be included in "Inventory" (a current asset) and included in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we will reclassify the long-term portion of linefill in third party assets (i.e. the portion of operating inventory valued at average cost not expected to be used within the next twelve months) out of "Inventory" (a current asset) and into "Inventory in Third Party Assets" (a long-term asset), which will be reflected as a separate line item within other assets on the consolidated balance sheet. This change in accounting principle is effective January 1, 2004 and is reflected in the consolidated statement of operations for the three months ended March 31, 2004 and the consolidated balance sheet as of March 31, 2004, included herein. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The impact on net income and net income per limited partner unit (basic and diluted) for the first quarter of 2004 is negligible and the pro forma impact to the first quarter of 2003 would have been an increase in net income of $1.6 million ($0.03 per basic and diluted limited partner unit) resulting in pro forma net income of $26 million and pro forma net income per limited partner unit (basic and diluted) of $0.49.

In conjunction with this change in accounting principle, we will classify cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification as cash flows from operating activities. Accordingly, the accompanying statement of cash flows for the three months ended March 31, 2004 and 2003 has been revised to reclassify the cash paid for linefill in assets owned from operating activities to investing activities. The effect of the reclassification was an increase to net cash provided by operating activities and net cash used in investing activities of $13.7 million for the three months ended March 31, 2003. The reclassification had no effect on the operating activities or investing activities for the three months ended March 31, 2004. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 would increase to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. In addition, net cash used in operating activities for the year ended December 31, 2001 would decrease from $30 million to $16.2 million.

Note 2—Acquisitions

Capline and Capwood Pipeline Systems

In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. The acquisition was accounted for under Statement of Financial Accounting Standards ("SFAS") No. 141 "Business Combinations." In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million. The proceeds from this issuance were used to pay down our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of these entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 667-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition (the "Capline acquisition") have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S., and delivered to several refineries and other pipelines.

The purchase price was allocated as follows (in millions):

Crude oil pipelines and facilities	$	151.4
Crude oil storage and terminal facilities		5.7
Land		1.3
Office equipment and other		0.1
Total	$	158.5

The following unaudited pro forma data is presented to show pro forma revenues, net income and basic and diluted net income per limited partner unit for the Partnership as if the Capline acquisition had occurred as of the beginning of the periods reported (in millions, except per unit amounts):

	Three Months Ended March 31, 2004	Three Months Ended March 31, 2003
Revenue	$ 3,812.3	$ 3,291.3
Net income before cumulative effect of accounting change	$ 35.1	$ 28.7
Net Income	$ 32.0	$ 28.7
Basic and diluted net income before cumulative effect of accounting change per limited partner unit	$ 0.56	$ 0.54
Basic net income per limited partner unit	$ 0.51	$ 0.54
Diluted net income per limited partner unit	$ 0.50	$ 0.54

Note 3—Trade Accounts Receivable

The majority of our trade accounts receivable relate to our gathering and marketing activities and can generally be described as high volume and low margin activities. 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, volumes 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, 2004, approximately 99% of our net trade accounts receivable were less than 60 days past the scheduled invoice date. Our allowance for doubtful accounts receivable totaled $0.2 million. We consider this reserve adequate; however, there is no assurance that actual amounts will not 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 4—Earnings Per Common Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for the dilutive effect of the contingent equity issuance related to the CANPET acquisition (see Note 5).

	Three months ended March 31,	
	2004	2003
	(in thousands, except per unit data)	
Net income	$ 27,876	$ 24,351
Less:		
General partner incentive distributions	(1,644)	(1,008)
General partner 2% ownership	(525)	(467)
Numerator for basic earnings per limited partner unit—net income available for common unitholders	25,707	22,876
Effect of dilutive securities:		
Increase in general partner's incentive distribution—Contingent equity issuance	(16)	—
Numerator for diluted earnings per limited partner unit	$ 25,691	$ 22,876
Denominator:		
Denominator for basic earnings per limited partner unit—weighted average number of limited partner units	58,414	50,166
Effect of dilutive securities:		
Contingent equity issuance(1)	603	—
Denominator for diluted earnings per limited partner unit—weighted average number of limited partner units	59,017	50,166
Basic net income per limited partner unit	$ 0.44	$ 0.46
Diluted net income per limited partner unit	$ 0.44	$ 0.46

(1) For purposes of calculating diluted earnings per limited partner unit we have assumed that the April 2004 contingent equity issuance related to the CANPET acquisition would be settled entirely in units, in accordance with SFAS No. 128 "Earnings Per Share." See Note 5 for the actual number of units issued to settle the obligation.

Note 5—Partners' Capital and Distributions

Subordinated Unit Conversion

Pursuant to the terms of our Partnership Agreement, in November 2003, 25% of the Subordinated Units converted to Common Units on a one-for-one basis. In February 2004, all of the remaining Subordinated Units converted to Common Units on a one-for-one basis.

As of December 31, 2003, the subordinated units have a debit balance in Partners' Capital of approximately $39.9 million. The debit balance is the result of several different factors including: (i) a low initial capital balance in connection with the formation of the partnership as a result of a low carry-over book basis in the assets contributed to the Partnership at the date of formation, (ii) a significant net loss in 1999 and (iii) distributions to unitholders that have exceeded net income allocated to unitholders each period. Additionally, the capital balances of the common unitholders and the General Partner have increased periodically as additional units have been sold and as the General Partner has made additional capital contributions associated with those offerings. The subordinated unitholders are not required to make any additional contributions associated with those offerings of common units. No additional Subordinated Units were issued after the initial issuance.

Issuance of Common Units

We issued approximately 138,000 common units during the first quarter of 2004 in conjunction with the vesting of awards under our Long-Term Incentive Plan ("LTIP"). See Note 6 for additional discussion. In addition, the General Partner made a proportional two percent contribution.

Distributions

On April 23, 2004, we declared a cash distribution of $0.5625 per unit on our outstanding common units, Class B common units and Class C common units. The distribution is payable on May 14, 2004, to unitholders of record on May 4, 2004, for the period January 1, 2004, through March 31, 2004. The total distribution to be paid is approximately $37.5 million, with approximately $35.0 million to be paid to our common unitholders and $0.7 million and $1.8 million to be paid to our general partner for its general partner and incentive distribution interests, respectively.

On January 22, 2004, we declared a cash distribution of $0.5625 per unit on our outstanding common units, Class B common units and subordinated units. The distribution was paid on February 13, 2004, to unitholders of record on February 3, 2004, for the period October 1, 2003, through December 31, 2003. The total distribution paid was approximately $35.2 million, with approximately $28.7 million paid to our common unitholders, $4.2 million paid to our subordinated unitholders and $0.7 million and $1.6 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Contingent Equity Issuance

In connection with the CANPET acquisition in July 2001, $26.5 million Canadian of the purchase price, payable in common units or cash at our option, was deferred subject to various performance objectives being met. These objectives were met as of December 31, 2003 and an increase to goodwill for this liability was recorded as of this date. The liability was satisfied on April 30, 2004. We issued approximately 385,000 common units and paid $6.5 million in cash to satisfy the obligation. The number of common units issued in satisfaction of the deferred payment was based upon $34.02 per share, the average trading price of our common units for the ten-day trading period prior to the payment date, and a Canadian dollar to U.S. dollar exchange rate of 1.35 to 1, the average noon-day exchange rate for the ten-day trading period prior to the payment date. In addition, $3.7 million in cash was paid for the distributions that would have been paid on the common units had they been outstanding since the effective date of the acquisition.

Private Placement of Series C Common Units

In connection with the acquisition discussed in Note 11, the partnership issued 3,245,700 Class C Common Units for $30.81 per unit in a private placement completed on April 15, 2004. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million. The Class C Common Units are unlisted securities that are pari passu in voting and distribution rights with the Partnership's publicly traded Common Units. The Class C Common Units are similar in many respects to the Partnership's Class B Common Units. The Class C Units are convertible into Common Units upon approval by the holders of a majority of the Common Units. Beginning six months from the closing of the private placement, the Class C Unitholders may request that the Partnership call a meeting of its Common Unitholders to consider approval of the conversion of the Class C Units into Common Units. If the approval of the conversion is not obtained within 120 days of the request, the Class C Unitholders will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a Common Unit. If the approval of the conversion is not secured within 90 days after the end of the 120-day period, the distribution right increases to 115%.

Note 6—Vesting of Unit Grants Under Long-Term Incentive Plan

As of March 31, 2004, grants of approximately 681,000 restricted phantom units were outstanding under our LTIP. During the first quarter of 2004, approximately 326,000 phantom units vested. We paid cash in lieu of delivery of common units for approximately 104,000 of the phantom units and issued approximately 138,000 new common units (after netting for taxes) in connection with the remainder of the vesting.

In addition, approximately 470,000 additional phantom units vested in May 2004. We paid cash rather than common units for approximately 202,000 of these phantom units and issued approximately 177,500 new common units (after netting for taxes) in connection with the remainder of that vesting.

Under generally accepted accounting principles, we are required to recognize an expense when it is considered probable that the phantom unit grants will vest. During the first quarter of 2004, we recognized $4.2 million of compensation expense related to the LTIP units. This was comprised of approximately $1.1 million related to units that vested in May and for which partial satisfaction of service period requirements has been met and approximately $3.1 million related to the vesting of approximately 101,000 additional phantom units. Some of these units will vest at a distribution level of $2.30, subject to applicable continuing employment requirements, and some will vest with the passage of time. We have concluded this vesting is probable and have thus accrued for this obligation. At a distribution level of $2.50 to $2.69, approximately 95,000 additional units would vest. At the time it is considered probable that this distribution level will be met, the costs associated with the vesting of these additional units will be accrued. We anticipate that, after giving effect to the May vesting and related tax withholding and cash settlement, approximately 845,000 phantom units will be available under the plan for future grant and approximately 216,000 phantom units will remain outstanding. In accordance with the provisions of the LTIP and applicable NYSE standards, no more than approximately 611,000 phantom unit grants can be satisfied by delivery of common units.

Note 7—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 and over-the-counter positions, and 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 hedged items.

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. The March 31, 2004, balance sheet includes assets of $24.2 million ($13.6 million current), liabilities of $24.7 million ($20.4 million current) and unrealized net losses deferred to Other Comprehensive Income ("OCI") of $15.0 million. Earnings for the three months ended March 31, 2004, include a gain of $10.0 million (including, $2.1 million, which was reclassified into earnings from OCI during the period).

As of March 31, 2004, 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. During the three months ended March 31, 2004, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Of the $15.0 million net loss deferred in OCI at March 31, 2004, a net loss of $9.2 million will be reclassified into earnings in the next twelve months and the remainder by 2013. Since a portion of these amounts are 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.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," these derivative instruments are recognized in the balance sheet or earnings at their fair values. The majority of our commodity price risk derivative instruments qualify for hedge accounting as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into OCI and recognized in revenues or cost of sales and operations in the periods during which the underlying physical transactions occur. At March 31, 2004, there was an unrealized loss of $9.1 million, deferred in OCI related to our commodity price risk activities. Approximately $8.5 million of the loss on these deferred positions will be reclassified into earnings in the next twelve months and the remainder by July 2006. Earnings for the three months ended March 31, 2004 include a net gain of $10.8 million (including $2.8 million, which was reclassified into earnings from OCI during the period). We have determined that our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our crude oil lease purchase activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues. There were no open positions under this program at March 31, 2004 and 2003. The realized earnings impact related to these activities for the three months ended March 31, 2004, was a loss of approximately $0.1 million.

Interest Rate Risk Hedging

At March 31, 2004, we have no open interest rate hedging instruments. However, there is approximately $5.8 million deferred in OCI that relates to instruments terminated and cash settled in 2003. The net deferred loss related to these instruments is being amortized into interest expense over the original terms of the terminated instruments (approximately fifty percent over three years and the remaining fifty percent over ten years). Approximately $0.4 million related to the terminated instruments has been reclassified into interest expense during the first quarter of 2004, and approximately $1.4 million will be reclassified for the entire year of 2004. In addition, earnings includes a loss of approximately $0.4 million that was reclassified out of OCI related to an instrument that matured in March 2004.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars (CAD), we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at times, a portion of our debt is denominated in Canadian dollars. At March 31, 2004, $3.7 million of our long-term debt was denominated in Canadian dollars ($4.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.31 to 1). All of these financial instruments are placed with what we believe to be large creditworthy financial institutions.

At March 31, 2004, we had forward exchange contracts that allow us to exchange $2.0 million Canadian for approximately $1.5 million U.S. quarterly during 2004 and approximately $1.0 million Canadian for approximately $0.7 million U.S. quarterly during 2005 (based on a Canadian dollar to U.S. dollar exchange rate of 1.33 to 1 and 1.34 to 1, respectively). In addition, at March 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $23.0 million, effectively converting this amount of our U.S. dollar denominated debt to $35.6 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. in May 2004 and May 2005 and has a final maturity in May 2006 of $19.0 million U.S.

The forward exchange contracts and forward extra option contracts qualify for hedge accounting as cash flow hedges and the cross currency swaps qualify for hedge accounting as fair value hedges, both in accordance with SFAS 133. Such derivative activity resulted in an unrealized loss of $0.2 million deferred in OCI related to our currency exchange rate cash flow hedges at March 31, 2004. The earnings impact related to our currency exchange rate fair value hedges was nominal for the three months ended March 31, 2004.

Note 8—Revenue Recognition Policy

Following is a description of our revenue recognition policy:

Gathering, Marketing, Terminalling and Storage Segment Revenues. Revenues from crude oil and LPG sales are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. All sales of crude oil and LPG are booked gross except in the case of barrel exchanges that are net settled. Terminalling and storage revenues, which are classified as Other revenues on the income statement, consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer on a given month; and (iii) terminal throughput charges to pump crude oil to connecting carriers. Revenues on storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil exits the terminal and is delivered to the connecting crude oil carrier. Any throughput volumes in transit at the end of a given month are treated as third-party inventory and do not incur storage fees. All terminalling and storage revenues are based on actual volumes and rates.

Pipeline Segment Revenues. Pipeline margin activities primarily consist of the purchase and sale of crude oil shipped on our San Joaquin Valley system from barrel exchanges and buy/sell arrangements. Revenues associated with these activities are recognized at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Revenues for these transactions are recorded gross except in the case of barrel exchanges that are net settled. All of our pipeline margin activities revenues are based on actual volumes and prices. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil at a published tariff as well as fees associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized. All pipeline tariff and fee revenues are based on actual volumes and rates.

Note 9—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. Department of Commerce. In 2002, we determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004 and intend to supplement that data to the extent applicable. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot estimate the ultimate impact of this matter.

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

Environmental

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At March 31, 2004, our reserve for environmental liabilities totaled approximately $6.8 million. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Other

The occurrence of a significant event not fully insured or indemnified 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. We believe that our levels of coverage and retention are generally consistent with those of similarly situated companies in our industry. 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 10—Operating Segments

Our operations consist of two operating segments: (1) Pipeline Operations—engages in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; and (2) Gathering, Marketing, Terminalling and Storage Operations—engages in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets.

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 and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow.

We evaluate segment performance based on (i) segment profit and (ii) maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs, and (iii) segment general and administrative expenses. Maintenance capital 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 not considered maintenance capital expenditures. 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. 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 and lease less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow. The following table reflects our results of operations for each segment for the periods indicated (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	Gathering Marketing, Terminalling & Storage	Total
		(in millions)	
Three Months Ended March 31, 2004			
Revenues:			
External Customers	$ 173.5	$ 3,631.1	$ 3,804.6
Intersegment[(1)]	15.8	0.2	16.0
Total revenues of reportable segments	$ 189.3	$ 3,631.3	$ 3,820.6
Segment profit[(3)]	$ 25.5	$ 28.1	$ 53.6
Noncash SFAS 133 impact[(2)]	$ —	$ 7.5	$ 7.5
Maintenance capital	$ 1.4	$ 0.3	$ 1.7

Three Months Ended March 31, 2003			
Revenues:			
External Customers	$ 159.0	$ 3,122.9	$ 3,281.9
Intersegment[(1)]	10.0	0.2	10.2
Total revenues of reportable segments	$ 169.0	$ 3,123.1	$ 3,292.1
Segment profit[(3)]	$ 20.2	$ 24.3	$ 44.5
Noncash SFAS 133 impact[(2)]	$ —	$ 0.9	$ 0.9
Maintenance capital	$ 1.4	$ 0.2	$ 1.6

(1) Intersegment sales are conducted at arms length.

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

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

	For the three months ended March 31,	
	2004	2003
Segment profit	$ 53.6	$ 44.5
Depreciation and amortization	(13.1)	(10.9)
Interest expense	(9.5)	(9.1)
Interest income and other, net	—	(0.1)
Income before cumulative effect of accounting change	$ 31.0	$ 24.4

Note 11—Subsequent Events

Link Acquisition

On April 1, 2004, we completed the acquisition of substantially all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $330 million, including $273 million of cash, the assumption of $49 million of liabilities and $8 million of transaction, closing and integration costs and other items. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions.

The acquisition was funded with cash on hand, borrowings under a new $200 million 364-day credit facility and borrowings under our existing revolving credit facilities. The new credit facility contains a twelve-month term out option, exercisable at our election, at the end of the primary term, bears interest at a rate of LIBOR plus a margin ranging from ..625% to 1.25%, depending upon our credit rating, and includes essentially the same covenants as our existing credit facilities. On April 15, we completed the private placement of 3,245,700 units of Class C Common Units for $30.81 per unit to a group of institutional investors. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million and was used to reduce the balance outstanding under our existing revolving credit facilities. The partnership has committed to use net proceeds from future debt and equity offerings to retire or reduce the amount outstanding under the new $200 million 364-day credit facility.

On April 2, 2004, the Office of the Attorney General of Texas delivered written notice to us that it was investigating the possibility that the acquisition of Link's assets might reduce competition in one or more markets within the petroleum products industry in the State of Texas. In connection with the Link purchase, both PAA and Link completed all necessary filings required under the Hart-Scott-Rodino Act, and the required 30-day waiting period expired on March 24, 2004 without any inquiry or request for additional information from the U.S. Department of Justice or the Federal Trade Commission. Representatives from the Antitrust and Civil Medicaid Fraud Division of the Office of the Attorney General of Texas indicated their investigation was prompted by complaints received from allegedly interested industry parties regarding the potential impact on competition in the Permian Basin area of West Texas. We understand that similar complaints have been received by the Federal Trade Commission, and that, consistent with federal-state protocols for conducting joint merger investigations, appropriate federal and state antitrust authorities will be coordinating their activities. We are cooperating fully with the antitrust enforcement authorities.

Cal Ven Acquisition

On May 7, 2004 we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The Cal Ven Pipeline System is comprised of approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and delivers crude oil into the Rainbow Pipeline System at Utikuma. The Rainbow Pipeline System then transports the crude south to the Edmonton market, where it can be used in local refineries or shipped on connecting pipelines to the U.S. market.