PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a)(1) and (2) Financial Statements and Financial Statement Schedules

See "Index to the Consolidated Financial Statements" set forth on Page F-1.

All schedules are omitted because they are not applicable, or the required information is shown in the consolidated financial statements or notes thereto.

(a)(3) Exhibits

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to Form 8 K filed August 27, 2001) as amended by Amendment No. 1 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P., dated as of April 15, 2004 (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the period ended March 31, 2004)
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the period ended March 31, 2004)
3.3	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the period ended March 31, 2004)
3.4	—	Second Amendment dated as of July 23, 2004 to Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC (incorporated by reference to Exhibit 3.1 to the Partnership's Current Report on Form 8-K filed July 27, 2004)
3.5	—	Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. (incorporated by reference to Exhibit 3.1 to Plains All American Pipeline, L.P.'s Current Report on Form 8-K filed on June 11, 2001)
3.6	—	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to Plains All American Pipeline, L.P.'s Registration Statement on Form S-3 filed on August 27, 2001)
3.7	—	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Plains All American Pipeline, L.P.'s Registration Statement on Form S-3 filed on August 27, 2001)
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002)
4.2	—	First Supplemental Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002)
4.3	—	Second Supplemental Indenture dated as of December 10, 2003. (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K for the Year Ended December 31, 2003)

4.4	—	Third Supplemental Indenture (Series A and Series B 4.750% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)
4.5	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)
4.6	—	Exchange and Registration Rights Agreement (4.750% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.6 to the Registration Statement on Form S-4, File No. 333-121168)
4.7	—	Exchange and Registration Rights Agreement (5.875% Senior Notes due 20016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (incorporated by reference to Exhibit 4.7 to the Registration Statement on Form S-4, File No. 333-121168)
4.8	—	Class C Common Unit Purchase Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners, L.P., Kayne Anderson MLP Fund, L.L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated March 31, 2004 (incorporated by reference to Exhibit 4.1 to the quarterly report on Form 10 Q for the period ended March 31, 2004)
4.9	—	Registration Rights Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Kayne Anderson MLP Fund, L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated April 15, 2004 (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10 Q for the period ended March 31, 2004)
10.1	—	Credit Agreement dated November 2, 2004 among Plains All American Pipeline, L.P. (as US Borrower), PMC (Nova Scotia) Company and Plains Marketing Canada, L.P. (as Canadian Borrowers), and Bank of America, N.A. (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the period ended September 30, 2004)
10.2	—	Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P. and the lenders named therein (incorporated by reference to Exhibit 10.1 to Form 8-K filed November 24, 2004)
10.3	—	Amended and Restated Marketing Agreement, dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the period ended June 30, 2004)
10.4	—	Amended and Restated Omnibus Agreement, dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC. (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the period ended June 30, 2004)

10.5	—	Contribution, Assignment and Amendment Agreement, dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 27, 2001)
10.6	—	Contribution, Assignment and Amendment Agreement, dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 11, 2001)
10.7	—	Separation Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to Form 8-K filed June 11, 2001)
10.8**	—	Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to Form 8-K filed June 11, 2001)
10.9**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Annex A to Proxy Statement filed December 7, 2004.)
10.10**	—	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to Form 10-Q filed June 30, 2003)
10.11**	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to Registration Statement on Form S-8, File No. 333-74920)
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001)
10.13**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001)
10.14	—	Asset Purchase and Sale Agreement between Murphy Oil Company Ltd. And Plains Marketing Canada, L.P. (incorporated by reference to Form 8-K filed May 10, 2001)
10.15	—	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to Registration Statement, File No. 333-64107)
10.16	—	Transportation Agreement dated August 2, 1993, between All American Pipeline Company and Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to Registration Statement, File No. 333-64107)
10.17	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the Year Ended December 31, 1998)

10.18	—	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the Year Ended December 31, 1998)
10.19**	—	Plains All American Inc., 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.05 to Annual Report on Form 10-K for the Year Ended December 31, 1998)
10.20+**	—	PMC (Nova Scotia) Company bonus program
10.21+**	—	Quarterly bonus summary
10.22+**	—	Directors' Compensation Summary
10.23	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the Year Ended December 31, 2001)
10.24**	—	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K filed February 23, 2005)
10.25**	—	Form of LTIP Grant Letter—executive officers (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K filed February 23, 2005)
10.26**	—	Form of LTIP Grant Letter—independent directors (incorporated by reference to Exhibit 10.3 to Current Report on Form 8-K filed February 23, 2005)
10.27**	—	Form of LTIP Grant Letter—designated directors (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K filed February 23, 2005)
10.28**	—	Form of LTIP Grant Letter—payment to entity (incorporated by reference to Exhibit 10.5 to Current Report on Form 8-K filed February 23, 2005)
21.1	—	List of Subsidiaries of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 21.1 to Registration Statement on Form S-1, File No. 333-119738)
23.1+	—	Consent of PricewaterhouseCoopers LLP
31.1+	—	Certification of Principal Executive Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
31.2+	—	Certification of Principal Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a)
32.1+	—	Certification of Principal Executive Officer pursuant to 18 USC § 1350
32.2+	—	Certification of Principal Financial Officer pursuant to 18 USC § 1350

+ Filed herewith

** Management compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

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

By: PLAINS ALL AMERICAN GP LLC,
its general partner

Date: March 2, 2005

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

Date: March 2, 2005

By: /s/ PHILLIP D. KRAMER
Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ GREG L. ARMSTRONG **Greg L. Armstrong**	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	Date: March 2, 2005
/s/ HARRY N. PEFANIS **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	Date: March 2, 2005
/s/ PHILLIP D. KRAMER **Phillip D. Kramer**	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	Date: March 2, 2005
/s/ TINA L. VAL **Tina L. Val**	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	Date: March 2, 2005
/s/ EVERARDO GOYANES **Everardo Goyanes**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ GARY R. PETERSEN **Gary R. Petersen**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ JOHN T. RAYMOND **John T. Raymond**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ ROBERT V. SINNOTT **Robert V. Sinnott**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ DAVID N. CAPOBIANCO **David N. Capobianco**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ ARTHUR L. SMITH **Arthur L. Smith**	Director of Plains All American GP LLC	Date: March 2, 2005
/s/ J. TAFT SYMONDS **J. Taft Symonds**	Director of Plains All American GP LLC	Date: March 2, 2005

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Plains All American Pipeline, L.P.'s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled "Internal Control—Integrated Framework" published by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") to evaluate the effectiveness of the Company's internal control over financial reporting. Based on that evaluation, management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2004. Our management's assessment of the effectiveness of the Partnership's internal control over financial reporting as of December 31, 2004 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

/s/ GREG L. ARMSTRONG

Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

/s/ PHILLIP D. KRAMER

Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

March 2, 2005

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
Plains All American Pipeline, L.P.:

We have completed an integrated audit of Plains All American Pipeline, L.P.'s 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income and of changes in accumulated other comprehensive income (loss) present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed its method of accounting for pipeline linefill in third party assets effective January 1, 2004.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Partnership maintained effective internal control over financial reporting as of December 31, 2004 based on criteria established in COSO, is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the COSO. The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Partnership's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Houston, Texas
March 2, 2005

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$12,988	$4,137
Trade accounts receivable, net	521,785	590,645
Inventory	498,200	105,967
Other current assets	68,229	32,225
Total current assets	1,101,202	732,974
PROPERTY AND EQUIPMENT	1,911,509	1,272,634
Accumulated depreciation	(183,887)	(121,595)
	1,727,622	1,151,039
OTHER ASSETS		
Pipeline linefill in owned assets	168,352	95,928
Inventory in third party assets	59,279	26,725
Other, net	103,956	88,965
Total assets	$3,160,411	$2,095,631
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$850,912	$603,460
Due to related parties	32,897	26,981
Short-term debt	175,472	127,259
Other current liabilities	54,436	44,219
Total current liabilities	1,113,717	801,919
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	151,753	70,000
Senior notes, net of unamortized discount of $2,729 and $1,009, respectively	797,271	448,991
Other long-term liabilities and deferred credits	27,466	27,994
Total liabilities	2,090,207	1,348,904
COMMITMENTS AND CONTINGENCIES (NOTES 11 and 12)		
PARTNERS' CAPITAL		
Common unitholders (62,740,218 and 49,502,556 units outstanding at December 31, 2004, and December 31, 2003, respectively)	919,826	744,073
Class B common unitholder (1,307,190 units outstanding at each date)	18,775	18,046
Class C common unitholders (3,245,700 units and no units outstanding at December 31, 2004, and December 31, 2003, respectively)	100,423	—
Subordinated unitholders (no units and 7,522,214 units outstanding at December 31, 2004, and December 31, 2003, respectively)	—	(39,913)
General partner	31,180	24,521
Total partners' capital	1,070,204	746,727
Total liabilities and partners' capital	$3,160,411	$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)

	Twelve Months Ended December 31,		
	2004	**2003**	**2002**
REVENUES			
Crude oil and LPG sales (includes approximately $11,246,951, $6,124,895 and $4,140,830, respectively, related to buy/sell transactions, see Note 2)	$20,184,319	$11,952,623	$7,892,405
Other gathering, marketing, terminalling and storage revenues	38,310	32,052	29,366
Pipeline margin activities revenues (includes approximately $149,797, $166,165 and $95,826, respectively, related to buy/sell transactions, see Note 2)	575,222	505,287	382,513
Pipeline tariff activities revenues	177,619	99,887	79,939
Total revenues	20,975,470	12,589,849	8,384,223
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs (includes approximately $11,137,669, $5,967,165 and $4,026,245, respectively, related to buy/sell transactions, see Note 2)	19,870,865	11,746,382	7,741,185
Pipeline margin activities purchases (includes approximately $142,538, $159,231 and $87,554, respectively, related to buy/sell transactions, see Note 2)	553,707	486,154	362,311
Field operating costs (excluding LTIP charge)	218,548	134,177	106,436
LTIP charge—operations	918	5,727	—
General and administrative expenses (excluding LTIP charge)	75,735	49,969	45,663
LTIP charge—general and administrative	7,013	23,063	—
Depreciation and amortization	67,241	46,821	34,068
Total costs and expenses	20,794,027	12,492,293	8,289,663
Gain on sales of assets	580	648	—
Asset impairment	(2,000)	—	—
OPERATING INCOME	180,023	98,204	94,560
OTHER INCOME/(EXPENSE)			
Interest expense (net of capitalized interest of $544, $524 and $773)	(46,676)	(35,226)	(29,057)
Interest and other income (expense), net	(211)	(3,530)	(211)
Income before cumulative effect of change in accounting principle	133,136	59,448	65,292
Cumulative effect of change in accounting principle	(3,130)	—	—
NET INCOME	$130,006	$59,448	$65,292
NET INCOME-LIMITED PARTNERS	$119,286	$53,473	$60,912
NET INCOME-GENERAL PARTNER	$10,720	$5,975	$4,380
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$1.94	$1.01	$1.34
Cumulative effect of change in accounting principle	(0.05)	—	—
Basic net income per limited partner unit	$1.89	$1.01	$1.34
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$1.94	$1.00	$1.34
Cumulative effect of change in accounting principle	(0.05)	—	—
Diluted net income per limited partner unit	$1.89	$1.00	$1.34
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	63,277	52,743	45,546
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	63,277	53,400	45,546

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)

	Year Ended December 31,		
	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$130,006	$59,448	$65,292
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	67,241	46,821	34,068
Gain on sales of assets	(580)	(648)	—
Cumulative effect of change in accounting principle	3,130	—	—
Allowance for doubtful accounts	400	360	146
Inventory valuation adjustment	2,032	—	—
SFAS 133 non-cash mark-to-market adjustment	(994)	(363)	(243)
Gain on foreign currency revaluation	(4,954)	—	—
Non-cash amortization of terminated interest rate swap	1,486	—	—
Net cash paid for terminated swaps	(1,465)	(6,152)	—
Loss on refinancing of debt	658	3,272	—
LTIP charge	7,931	28,790	—
Impairment of long-lived assets	2,000	—	—
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other assets	(30,364)	(102,005)	(136,480)
Inventory	(398,671)	(38,941)	105,944
Accounts payable and other liabilities	327,449	121,274	107,265
Inventory in third-party assets	(7,248)	—	—
Due to related parties	5,911	3,452	8,962
Net cash provided by operating activities	103,968	115,308	184,954
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(535,266)	(168,359)	(324,628)
Additions to property and equipment	(116,944)	(65,416)	(40,590)
Cash paid for linefill on assets owned	(1,989)	(46,790)	(11,060)
Proceeds from sales of assets	3,012	8,450	1,437
Net cash used in investing activities	(651,187)	(272,115)	(374,841)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on long-term revolving credit facilities and other	64,893	62,473	(42,144)
Net borrowings on working capital revolving credit facility	62,900	25,300	—
Net repayments on short-term letter of credit and hedged inventory facilities	(20,090)	(6,197)	(4,770)
Principal payments on senior secured term loans	—	(297,000)	(3,000)
Cash paid in connection with financing arrangements	(5,073)	(5,191)	(5,435)
Net proceeds from the issuance of common units (Note 6)	262,132	250,341	145,046
Proceeds from the issuance of senior notes	348,068	249,340	199,600
Distributions paid to unitholders and general partner	(158,352)	(121,822)	(99,841)
Net cash provided by financing activities	554,478	157,244	189,456
Effect of translation adjustment on cash	1,592	199	421
Net increase (decrease) in cash and cash equivalents	8,851	636	(10)
Cash and cash equivalents, beginning of period	4,137	3,501	3,511
Cash and cash equivalents, end of period	$12,988	$4,137	$3,501
Cash paid for interest, net of amounts capitalized	$40,780	$36,382	$28,550

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

(in thousands)

	Common Units		Class B Common Units		Class C Common Units		Subordinated Units		General Partner Amount	Total Units	Total Partners' Capital Amount
	Units	Amount	Units	Amount	Units	Amount	Units	Amount			
						(unaudited)					
Balance at December 31, 2001	31,916	$408,562	1,307	$19,534	—	$—	10,030	$(38,891)	$13,592	43,253	$402,797
Issuance of common units	6,325	142,013	—	—	—	—	—	—	3,033	6,325	145,046
Net income	—	45,857	—	1,736	—	—	—	13,319	4,380	—	65,292
Distributions	—	(70,821)	—	(2,762)	—	—	—	(21,188)	(5,070)	—	(99,841)
Other comprehensive loss	—	(1,183)	—	(45)	—	—	—	(343)	(113)	—	(1,684)
Balance at December 31, 2002	38,241	$524,428	1,307	$18,463	—	$—	10,030	$(47,103)	$15,822	49,578	$511,610
Issuance of common units	8,736	245,093	—	—	—	—	—	—	5,237	8,736	250,330
Issuance of common units under LTIP	18	555	—	—	—	—	—	—	11	18	566
Net income	—	41,278	—	1,370	—	—	—	10,825	5,975	—	59,448
Conversion of subordinated units	2,507	(9,823)	—	—	—	—	(2,507)	9,823	—	—	—
Distributions	—	(89,801)	—	(2,860)	—	—	—	(21,939)	(7,222)	—	(121,822)
Other comprehensive income	—	32,343	—	1,073	—	—	—	8,481	4,698	—	46,595
Balance at December 31, 2003	49,502	$744,073	1,307	$18,046	—	$—	7,523	$(39,913)	$24,521	58,332	$746,727
Issuance of common units	4,968	157,568	—	—	—	—	—	—	3,371	4,968	160,939
Issuance of common units under LTIP	362	11,772	—	—	—	—	—	—	238	362	12,010
Private placement of Class C common units	—	—	—	—	3,246	98,782	—	—	2,041	3,246	100,823
Issuance of units for acquisition contingent consideration	385	13,082	—	—	—	—	—	—	267	385	13,349
Distributions	—	(134,175)	—	(3,009)	—	(5,648)	—	(4,231)	(11,289)	—	(158,352)
Other comprehensive income	—	59,886	—	1,248	—	3,098	—	(841)	1,311	—	64,702
Net income	—	111,161	—	2,490	—	4,191	—	1,444	10,720	—	130,006
Conversion of subordinated units	7,523	(43,541)	—	—	—	—	(7,523)	43,541	—	—	—
Balance at December 31, 2004	62,740	$919,826	1,307	$18,775	3,246	$100,423	—	$—	$31,180	67,293	$1,070,204

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

	Year Ended December 31, 2004	2003	2002
	(in thousands)		
Net income	$130,006	$59,448	$65,292
Other comprehensive income (loss)	64,702	46,595	(1,684)
Comprehensive income	$194,708	$106,043	$63,608

CONSOLIDATED STATEMENT OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
	(in thousands)		
Balance at December 31, 2001	$(4,740)	$(8,002)	$(12,742)
Reclassification adjustments for settled contracts	797	—	797
Changes in fair value of outstanding hedge positions	(4,264)	—	(4,264)
Currency translation adjustment	—	1,783	1,783
2002 Activity	(3,467)	1,783	(1,684)
Balance at December 31, 2002	(8,207)	(6,219)	(14,426)
Reclassification adjustments for settled contracts	(28,151)	—	(28,151)
Changes in fair value of outstanding hedge positions	28,666	—	28,666
Currency translation adjustment	—	46,080	46,080
2003 Activity	515	46,080	46,595
Balance at December 31, 2003	(7,692)	39,861	32,169
Reclassification adjustments for settled contracts	13,262	—	13,262
Changes in fair value of outstanding hedge positions	20,367	—	20,367
Currency translation adjustment	—	31,073	31,073
2004 Activity	33,629	31,073	64,702
Balance at December 31, 2004	$25,937	$70,934	$96,871

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

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. ("PAA") is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our 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 liquified petroleum gas and 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 and at major market hubs in the United States and Canada.

Our 2% general partner interest is held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Plains All American GP LLC manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to the management of the Partnership. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by seven owners with interests ranging from 44% to 3.2%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2004 and 2003, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income (loss) and changes in accumulated other comprehensive income for the years ended December 31, 2004, 2003 and 2002. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior periods to conform with the current period presentation. The accompanying consolidated financial statements of PAA include PAA and all of its wholly-owned subsidiaries. Investments in 50% or less owned affiliates, over which the Company has significant influence, are accounted for by the equity method.

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, previously 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, is 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" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now 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 year ended December 31, 2004 and the consolidated balance sheets as of December 31, 2004 and 2003 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 pro forma impact for the year ended December 31, 2003 would have been an increase to net income of approximately $2.0 million ($0.04 per basic and diluted limited partner unit) resulting in pro forma net income of $61.5 million and pro forma basic net income per limited partner unit of $1.05 and pro forma diluted net income per limited partner unit of $1.04. The pro forma impact for the year ended December 31, 2002 would have been a decrease to net income of approximately $0.1 million (no impact to basic and diluted limited partner unit) resulting in pro forma net income of $65.2 million and pro forma basic net income per limited partner unit of $1.34 and pro forma diluted net income per limited partner unit of $1.34.

In conjunction with this change in accounting principle, we have classified 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 of cash flows from operating activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively.

Note 2—Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates we make include: (i) accruals related to purchases and sales, (ii) mark-to-market estimates pursuant to Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, (iii) contingent liability accruals and (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Buy/sell transactions. The Emerging Issues Task Force ("EITF") is currently considering Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty," ("EITF No. 04-13"), which relates to buy/sell transactions. The issues to be addressed by the EITF are i) under what circumstances should two or more transactions with the same counterparty be viewed as a single nonmonetary transaction within the scope of APB No. 29; and ii) if nonmonetary transactions within the scope of APB No. 29 involve inventory, are there any circumstances under which the transactions should be recognized at fair value.

Buy/sell transactions are contractual arrangements in which we agree to buy a specific quantity and quality of crude oil or LPG to be delivered at a specific location while simultaneously agreeing to sell a specified quantity and quality of crude oil or LPG at a different location, usually with the same counterparty. These arrangements are generally designed to increase our margin through a variety of methods, including reducing our transportation or storage costs or acquiring a grade of crude oil that more closely matches our physical delivery requirement to one of our other customers. The value difference between purchases and sales is referred to as margin and is primarily due to grade, quality or location differentials. All buy/sell transactions result in us making or receiving physical delivery of the product, involve the attendant risks and rewards of ownership, including title transfer, assumption of environmental risk, transportation scheduling, credit risk and counterparty nonperformance risk, and such transactions are settled in cash similar to all other purchases and sales. Accordingly, such transactions are recorded in both revenues and purchases as separate sales and purchase transactions on a "gross" basis.

We believe that buy/sell transactions are monetary in nature and thus outside the scope of APB Opinion No. 29, "Accounting for Nonmonetary Transactions" ("APB No. 29"). Additionally, we have evaluated EITF No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent" ("EITF No. 99-19") and, based on that evaluation, we believe that recording these transactions on a gross basis is appropriate. If the EITF were to determine that these transactions should be accounted for as monetary transactions on a gross basis, no change in our accounting policy for buy/sell transactions would be necessary. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions qualifying for fair value recognition and require a net presentation of such transactions, the amounts of revenues and purchases associated with buy/sell transactions would be netted in our consolidated statement of operations, but there would be no effect on operating income, net income or cash flows from operating activities. If the EITF were to determine that these transactions should be accounted for as nonmonetary transactions not qualifying for fair value recognition, these amounts of revenues and purchases would be netted in our consolidated statement of operations and there could be an impact on operating income and net income related to the timing of the ultimate sale of product purchased in the "buy" side of the buy/sell transaction. However, we do not believe any impact on operating income, net income or cash flows from operating activities would be material.

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. Sales of crude oil and LPG consist of outright sales contracts and buy/sell arrangements which are booked gross as well as barrel exchanges which are booked net.

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.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil and LPG purchased in outright purchases as well as buy/sell arrangements; (ii) third party transportation and storage, whether by pipeline, truck or barge; and (iii) expenses to issue letters of credit to support these purchases. These purchases are accrued at the time title transfers to us which occurs upon receipt of the product.

Operating Expenses and General and Administrative Expenses

Operating expenses consist of various field and pipeline operating expenses including fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs, certain information system and legal costs, office rent, contract and consultant costs, and audit and tax fees.

Foreign Currency Transactions

Assets and liabilities of subsidiaries with a functional currency other than the U.S. Dollar are translated at period end rates of exchange and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in partners' capital. Gains and losses from foreign currency transactions (transactions denominated in a currency other than the entity's functional currency) are included in the consolidated statement of operations. These gains totaled approximately $5.0 million for the year ended December 31, 2004, and were immaterial for the years ended December 31, 2003 and 2002.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that any possible credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG. There was a nominal amount due from related parties at December 31, 2004 and no amounts due from related parties at December 31, 2003. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or "parental" guarantees. At December 31, 2004, we had received approximately $20.3 million of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and assess whether our allowance for doubtful trade accounts receivable is adequate. Actual balances are not applied against the reserve until all collection efforts have been exhausted. At December 31, 2004 and 2003, substantially all of our net accounts receivable classified as current were less than 60 days past their scheduled invoice date, and our allowance for doubtful accounts receivable (the entire balance of which is classified as current) totaled $0.6 million and $0.2 million, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, there is no assurance that actual amounts will not vary significantly from estimated amounts. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	December 31,		
	2004	**2003**	**2002**
Balance at beginning of year	$0.2	$8.1	$8.0
Applied to accounts receivable balances	—	(8.3)	—
Increase in reserve charged to expense	0.4	0.4	0.1
Balance at end of year	$0.6	$0.2	$8.1

Inventory and Pipeline 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. During the fourth quarter of 2004, we recorded a $2.0 million noncash charge related to the writedown of our LPG inventory. Linefill and minimum working inventory requirements are recorded at historical cost and consist of crude oil and LPG used to pack an operated pipeline 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 December 31, 2004 and 2003, inventory and linefill consisted of:

	December 31, 2004			December 31, 2003		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory						
Crude oil	8,716	$396.2	$45.46	1,676	$50.6	$30.19
LPG	2,857	100.1	35.04	2,243	53.8	23.99
Other	—	1.9	N/A	—	1.6	N/A
Inventory subtotal	11,573	$498.2		3,919	$106.0	
Inventory in third-party assets						
Crude oil	1,294	$48.7	37.64	853	$22.6	26.49
LPG	318	10.6	33.33	183	4.1	22.40
Inventory in third-party assets subtotal	1,612	$59.3		1,036	$26.7	
Linefill						
Crude oil linefill	6,015	$168.4	28.00	3,767	$95.9	25.46
Total	19,200	$725.9		8,722	$228.6	

Property and Equipment

Property and equipment, net is stated at cost and consisted of the following:

	December 31,	
	2004	2003
	(in millions)	
Crude oil pipelines and facilities	$1,605.3	$1,114.5
Crude oil and LPG storage and terminal facilities	169.6	100.8
Trucking equipment and other	117.6	43.8
Office property and equipment	19.0	13.5
	1,911.5	1,272.6
Less accumulated depreciation	(183.9)	(121.6)
	$1,727.6	$1,151.0

Depreciation expense for each of the three years in the period ended December 31, 2004, was $63.3 million, $42.4 million and $30.2 million, respectively. Our policy is to depreciate property and equipment over estimated useful lives as follows:

- crude oil pipelines and facilities—30 to 40 years;
- crude oil and LPG storage and terminal facilities—30 to 40 years;
- trucking equipment and other—5 to 15 years; and
- office property and equipment—3 to 5 years

We calculate our depreciation and amortization using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2004, 2003 and 2002, capitalized interest was $0.5 million, $0.5 million and $0.8 million, respectively. In addition, costs required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives are capitalized and classified as 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.

Asset Retirement Obligation

In June 2001, the FASB issued SFAS No. 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows.

Some of our assets, primarily related to our pipeline operations segment, have obligations to perform remediation and, in some instances, removal activities when the asset is abandoned. However, the majority of these obligations are associated with active assets and the fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. A small portion of these obligations relate to assets that are inactive and although the ultimate timing and cost to settle these obligations is not known with certainty, we can reasonably estimate the obligation. As such, we have estimated that the fair value of these obligations is approximately $2.5 million at December 31, 2004. For those obligations that are currently indeterminate, we will record asset retirement obligations in the period in which we can reasonably determine the settlement dates.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written-down to estimated fair value in accordance with SFAS No. 144 "Accounting for the Impairment or Disposal of Long-Lived Assets," as amended. Under SFAS 144, an asset shall be tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount the carrying value exceeds the fair value of the asset is recognized. Fair value is generally determined from estimated discounted future net cash flows. We adopted SFAS 144 on January 1, 2002. In 2004, we recognized a charge of approximately $2.0 million associated with taking our pipeline in the Illinois Basin out of service. The impairment represents the remaining net book value of the idled pipeline system. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks.

Other Assets

Other assets consist of the following:

	December 31, 2004	December 31, 2003
	(in millions)	
Goodwill	$47.1	$39.4
Deposit on pending acquisition	11.9	15.8
Debt issue costs	15.5	12.1
Investment in affiliate	8.2	7.8
Fair value of derivative instruments	8.6	5.9
Intangible assets	2.7	2.6
Other	14.0	7.1
	108.0	90.7
Less accumulated amortization	(4.1)	(1.7)
	$103.9	$89.0

In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," we test goodwill and other intangible assets periodically to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. If the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not impaired. An impairment loss is recognized for intangibles if the carrying amount of an intangible asset is not recoverable and its carrying amount exceeds its fair value. As of December 31, 2004, substantially all of our goodwill is allocated to our gathering, marketing, terminalling and storage operations ("GMT&S"). Since adoption of SFAS 142, the company has not recognized any impairment of goodwill.

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized costs of approximately $5.9 million and $5.1 million in 2004 and 2003, respectively. In addition, during 2004 we wrote off approximately $0.7 million of unamortized costs and approximately $1.7 million of fully amortized costs and the related accumulated amortization. During 2003, we wrote off comparable amounts totaling $3.3 million and $11.3 million, respectively.

Amortization of other assets for each of the three years in the period ended December 31, 2004, was $3.9 million, $4.4 million and $3.9 million, respectively.

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense or capitalize, as appropriate, environmental expenditures. We expense expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We capitalize environmental liabilities assumed in business combinations based on the fair value of the environmental obligations caused by past operations of the acquired company.

Income and Other Taxes

Except as noted below, no provision for U.S. federal or Canadian income taxes related to our operations is included in the accompanying consolidated financial statements, because as a partnership we are not subject to federal, state or provincial income tax and the tax effect of our activities accrues to the unitholders. Net earnings for financial statement purposes may differ significantly from taxable income reportable to unitholders as a result of differences between the tax bases and financial reporting bases of assets and liabilities and the taxable income allocation requirements under the partnership agreement. Individual unitholders will have different investment bases depending upon the timing and price of acquisition of partnership units. Further, each unitholder's tax accounting, which is partially dependent upon the unitholder's tax position, may differ from the accounting followed in the consolidated financial statements. Accordingly, there could be significant differences between each individual unitholder's tax bases and the unitholder's share of the net assets reported in the consolidated financial statements. We do not have access to information about each individual unitholder's tax attributes, and the aggregate tax basis cannot be readily determined. Accordingly, we do not believe that in our circumstances, the aggregate difference would be meaningful information.

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital -based tax at federal and provincial levels. For the years presented, these amounts were immaterial.

In addition to federal income taxes, owners of our common units may be subject to other taxes, such as state and local and Canadian federal and provincial taxes, unincorporated business taxes, and estate, inheritance or intangible taxes that may be imposed by the various jurisdictions in which we do business or own property. A unitholder may be required to file Canadian federal income tax returns, pay Canadian federal and provincial income taxes, file state income tax returns and pay taxes in various states.

Recent Accounting Pronouncements

In March 2004, the Emerging Issues Task Force issued Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two-Class Method under FASB Statement No. 128." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by companies that have issued securities, other than common stock, that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. There was no impact on earnings per limited partner unit in the periods presented because of the adoption of EITF 03-06. The adoption of EITF 03-06 may have an impact on earnings per limited partner unit in future periods if net income exceeds distributions or if other participating securities are issued.

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. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 (collectively "SFAS 133"). SFAS 133 requires that changes in derivative instruments fair value be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value are deferred to Other Comprehensive Income ("OCI") and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

Net Income Per Unit

Basic and diluted net income per unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units during the period, including common units and subordinated units. Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership. The following table sets forth the computation of basic and diluted net income per limited partner unit for 2004, 2003 and 2002.

	Year ended December 31,		
	2004	2003	2002
Net income	$130,006	$59,448	$65,292
Less:			
Incentive distribution right	(8,286)	(4,884)	(3,137)
Subtotal	121,720	54,564	62,155
General partner 2% ownership	(2,434)	(1,091)	(1,243)
Numerator for basic earnings per limited partner unit:			
Net income available for limited partners	119,286	53,473	60,912
Effect of dilutive securities:			
Increase in general partner's incentive distribution-contingent equity issuance	—	(61)	—
Numerator for diluted earnings per limited partner unit	$119,286	$53,412	$60,912
Denominator:			
Denominator for basic earnings per limited partner unit—weighted average number of limited partner units	63,277	52,743	45,546
Effect of dilutive securities:			
Contingent equity issuance	—	657	—
Denominator for diluted earnings per limited partner unit—weighted average number of limited partner units	63,277	53,400	45,546
Basic net income per limited partner unit	$1.89	$1.01	$1.34
Diluted net income per limited partner unit	$1.89	$1.00	$1.34

Note 3—Acquisitions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method. In addition, we adopted SFAS No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001.

Significant Acquisitions

Link Energy LLC

On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million, including $268 million of cash (net of approximately $5.5 million subsequently returned to us from an indemnity escrow account) and approximately $64 million of net liabilities assumed and acquisition-related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active 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 results of operations and assets and liabilities from this acquisition (the "Link acquisition") have been included in our consolidated financial statements and in both our pipeline operations and gathering, marketing, terminalling and storage operations segments since April 1, 2004.

The purchase price was allocated as follows and includes goodwill primarily related to Link's gathering and marketing business (in millions):

Cash paid for acquisition(1)	$268.0
Fair value of net liabilities assumed:	
Accounts receivable(2)	409.4
Other current assets	1.8
Accounts payable and accrued liabilities(2)	(459.6)
Other current liabilities	(8.5)
Other long-term liabilities	(7.4)
Total net liabilities assumed	(64.3)
Total purchase price	$332.3
Purchase price allocation	
Property and equipment	$260.2
Inventory	3.4
Linefill	55.4
Inventory in third party assets	8.1
Goodwill	5.0
Other long term assets	0.2
Total	$332.3

(1) Cash paid does not include the subsequent payment of various transaction and other acquisition related costs.

(2) Accounts receivable and accounts payable are gross and do not reflect the adjustment of approximately $250 million to net settle, based on contractual agreements with our counterparties.

The total purchase price includes (i) approximately $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to involuntarily terminate and relocate employees in conjunction with the acquisition, and (iii) approximately $11.0 million related to costs to terminate a contract assumed in the acquisition. These activities are substantially complete and the majority of the related costs have been incurred as of December 31, 2004. In addition, we anticipate making capital expenditures of approximately $28.0 million ($18.0 million in 2005) to upgrade certain of the assets and comply with certain regulatory requirements.

The acquisition was initially funded with cash on hand, borrowings under our existing revolving credit facilities and under a new $200 million, 364 -day credit facility. In connection with the acquisition, on April 15, 2004, we completed the private placement of 3,245,700 Class C common units to a group of institutional investors. During the third quarter of 2004, we completed a public offering of common units and the sale of an aggregate of $350 million of senior notes. A portion of the proceeds from these transactions was used to retire the $200 million, 364-day credit facility.

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 (the "FTC"). On April 2, 2004, the Office of the Attorney General of Texas (the "Texas AG") 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. Such investigation was coordinated with the FTC, consistent with federal-state protocols for conducting joint merger investigations. We cooperated fully with the antitrust enforcement authorities, including the provision of information at the request of the Texas AG Antitrust Division. In late 2004, we were informed by the Texas AG Antitrust Division and subsequently by the FTC that they were closing their investigation and do not have any current intentions to pursue any additional course of action with respect to these assets.

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. 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, after paying approximately $4.1 million of transaction costs. 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 633-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

Pro Forma Data

The following unaudited pro forma data is presented to show pro forma revenues, income before cumulative effect of change in accounting principle, net income, basic and diluted income before cumulative effect of accounting change per limited partner unit and basic and diluted net income per limited partner unit for the Partnership as if the Capline and Link acquisitions had occurred as of the beginning of the periods reported:

	Year Ended December 31,	
	2004	**2003**
	(unaudited) (in millions, except per unit amounts)	
Revenues	$21,023.4	$12,807.5
Income before cumulative effect of change in accounting principle(1)	$115.9	$110.4
Net income(2)	$112.8	$106.4
Basic income before cumulative effect of change in accounting principle per limited partner unit(1)	$1.77	$1.97
Diluted income before cumulative effect of change in accounting principle per limited partner unit(1)	$1.77	$1.94
Basic net income per limited partner unit(2)	$1.72	$1.90
Diluted net income per limited partner unit(2)	$1.72	$1.87

(1) Includes a net gain in the 2003 period of approximately $67.5 million related to Link's predecessor company's reorganization, discharge of debt and fresh start adjustments.

(2) The 2003 period includes the amounts described in note (1) above as well as a loss of approximately $4.0 million related to Link's predecessor company's cumulative effect of change in accounting principle.

Shell West Texas Assets

On August 1, 2002, we acquired from Shell Pipeline Company LP and Equilon Enterprises LLC interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 9.0 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas (the "Shell acquisition"). The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since that date. The primary assets included in the transaction were interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. These assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we are a provider of storage and terminalling services. The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs. The entire purchase price was allocated to property and equipment.

Other Acquisitions

2004 Acquisitions

During 2004, in addition to the Link and Capline acquisitions, we completed several other acquisitions for aggregate consideration totaling $58.7 million including transaction costs. These acquisitions include crude oil mainline and gathering pipelines and propane storage facilities. The aggregate purchase price was allocated to property and equipment.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration totaling approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. The aggregate purchase price was allocated as follows (in million):

Crude oil pipelines and facilities	$138.0
Crude oil and LPG storage facilities	7.3
Trucking equipment and other	7.8
Office property and equipment	1.2
Pipeline Linefill	4.7
Goodwill	0.5
	$159.5

2002 Acquisitions

During 2002, in addition to the Shell acquisition, we completed two acquisitions for aggregate consideration totaling approximately $15.9 million including transaction costs. These acquisitions include crude oil pipeline, gathering and marketing assets and a 22% equity interest in a pipeline company. With the exception of $1.3 million that was allocated to goodwill, the aggregate purchase price was allocated to property and equipment.

Note 4—Asset Dispositions

Shutdown and Sale of Rancho Pipeline System

We acquired an interest in the Rancho Pipeline System from Shell in August 2002. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with SFAS No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred our ownership interest in approximately 241 miles of the total 458 miles of the pipeline in exchange for $4.0 million and approximately 500,000 barrels of crude oil tankage in West Texas. In August 2004, we sold our interest in the remaining portion of the system for approximately $0.9 million, including the assumption of all liabilities typically associated with pipelines of this type. We recognized a gain of approximately $0.6 million on this transaction.

Other Dispositions

During 2004, 2003 and 2002, we sold various other property and equipment for proceeds totaling approximately $3.0 million, $8.5 million and $1.4 million, respectively. Gains of approximately $0.6 million were recognized in both 2004 (including the gain on the sale of the Rancho Pipeline System) and 2003, respectively, and no gain or loss was recognized in 2002.

Note 5—Debt

Debt consists of the following:

	December 31,	
	2004	2003
	(in millions)	
Short-term debt:		
Senior secured hedged inventory borrowing facility bearing interest at a rate of 3.0% and 1.9% at December 31, 2004 and December 31, 2003, respectively	$80.4	$100.5
Working capital borrowings, bearing interest at a rate of 3.7% and 4.0% at December 31, 2004 and December 31, 2003, respectively[1]	88.2	25.3
Other	6.9	1.5
Total short-term debt	175.5	127.3
Long-term debt:		
Senior unsecured revolving credit facility, bearing interest at 3.5% at December 31, 2004[1]	$143.6	$—
Senior unsecured $170 million Canadian revolving credit facility, bearing interest at a rate of 2.2% at December 31, 2003	—	70.0
4.75% senior notes due August 2009, net of unamortized discount of $0.7 million at December 31, 2004	174.3	—
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.3 million at December 31, 2004 and December 31, 2003, respectively	199.7	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.6 million and $0.7 million at December 31, 2004 and December 31, 2003, respectively	249.4	249.3
5.88% senior notes due August 2016, net of unamortized discount of $1.1 million at December 31, 2004	173.9	—
Other	8.1	—
Total long-term debt[1]	949.0	519.0
Total debt	$1,124.5	$646.3

(1) At December 31, 2004 and 2003, we have classified $88.2 million and $25.3 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings under this facility and primarily are for hedged LPG inventory and New York Mercantile Exchange ("NYMEX") margin deposits and must be repaid within one year.

Credit Facilities

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. At December 31, 2004, approximately $231.8 million was outstanding under this facility (including $88.2 million classified as short-term).

Note 5—Debt

Also in the fourth quarter of 2004, we amended and renewed our senior secured hedged inventory facility; increasing the facility to $425 million, with the ability to further increase the facility in the future by an incremental $75 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are collateralized by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005.

Senior Notes

During August 2004, we completed the sale of $175 million of 4.75% Senior Notes due 2009 and $175 million of 5.88% Senior Notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. Interest payments are due on February 15 and August 15 of each year.

During December 2003, we completed the sale of $250 million of 5.625% senior notes due in December 2013. The notes were issued at a discount of $0.7 million, resulting in an effective interest rate of 5.66%. Interest payments are due on June 15 and December 15 of each year.

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued at a discount of $0.4 million, resulting in an effective interest rate of 7.78%. Interest payments are due on April 15 and October 15 of each year.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

Covenants and Compliance

Our credit agreements and the indentures governing the senior notes contain cross default provisions. Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions;
- sell substantially all of our assets or enter into a merger or consolidation.

Our credit facility treats a change of control as an event of default and also requires us to maintain:

- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt coverage ratio which will not be greater than 4.75 to 1.0 on all outstanding debt and 5.25 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. We are currently in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

As is customary in our industry, and in connection with our crude oil marketing, we provide certain suppliers and transporters with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2004 and 2003, we had outstanding letters of credit of approximately $98.0 million and $57.9 million, respectively. In addition to changes in the level of activity and other factors, the amount of letters of credit outstanding varies based on NYMEX crude oil prices, which were $43.34 per barrel and $32.52 per barrel at December 31, 2004 and 2003, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2004, was approximately 8 years and the aggregate maturities for the for the next five years are as follows:

Calendar Year	Payment
2005	$—
2006	3.7
2007	3.6
2008	0.8
2009	318.6
Thereafter	625.0
Total[(1)]	951.7

(1) Reflects aggregate unamortized discount of $2.7 million on our various senior notes.

Note 6—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2004 consists of 67,293,108 common units, including 1,307,190 Class B common units and 3,245,700 Class C common units, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), and a 2% general partner interest.

Class B and Class C Common Units

The Class B common units and Class C common units were *pari passu* with common units with respect to quarterly distributions. In accordance with a common unitholder vote at a special meeting on January 20, 2005, each Class B common unit and Class C common unit became convertible into one common unit upon request of the holder. In February 2005, all of the Class B and Class C common units converted into common units.

Subordinated Units and Conversion

Pursuant to the terms of our Partnership Agreement and having satisfied the financial tests contained therein, 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.

The subordinated units have a debit balance in Partners' Capital of approximately $39.9 million at December 31, 2003. 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.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, generally the general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our minimum quarterly distributions ("MQD"), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions"). Cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2004		2003		2002	
	Distribution[1]	Excess over MQD	Distribution[1]	Excess over MQD	Distribution[1]	Excess over MQD
First Quarter	$0.5625	$0.1125	$0.5375	$0.0875	$0.5125	$0.0625
Second Quarter	$0.5625	$0.1125	$0.5500	$0.1000	$0.5250	$0.0750
Third Quarter	$0.5775	$0.1275	$0.5500	$0.1000	$0.5375	$0.0875
Fourth Quarter	$0.6000	$0.1500	$0.5500	$0.1000	$0.5375	$0.0875

(1) Distributions represent those declared and paid in the applicable period.

Distributions

We will distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established by our general partner for future requirements. Total cash distributions made were as follows:

Year	Common Units	Subordinated Units	GP 2%	GP Incentive	Total	Distribution per unit
	(in millions, except per unit amounts)					
2004	$142.9	$4.2	$3.0	$8.3	$158.4	$2.30
2003	$92.7	$21.9	$2.3	$4.9	$121.8	$2.19
2002	$73.6	$21.1	$2.0	$3.1	$99.8	$2.11

On January 25, 2005, we declared a cash distribution of $0.6125 per unit on our outstanding common units, Class B common units and Class C common units. The distribution was paid on February 14, 2005, to unitholders of record on February 4, 2005, for the period October 1, 2004, through December 31, 2004. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and $0.8 million and $3.0 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

During the three years ended December 31, 2004, we completed the following public equity offerings of our common units:

Period	Units	Gross Unit Price	Proceeds from Sale	GP Contribution	Costs	Net Proceeds
		(in millions, except per unit amounts)				
July/August 2004	4,968,000	$33.25	$165.2	$3.4	$7.7	$160.9
December 2003	2,840,800	$31.94	$90.7	$1.8	$4.1	$88.4
September 2003	3,250,000	$30.91	$100.5	$2.1	$4.6	$98.0
March 2003	2,645,000	$24.80	$65.6	$1.3	$3.0	$63.9
August 2002	6,325,000	$23.50	$148.6	$3.0	$6.6	$145.0

Private Placement of Class C Common Units

In connection with the Link acquisition, on April 15, 2004 we issued 3,245,700 Class C common units for $30.81 per unit in a private placement to a group of institutional investors consisting of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors. Affiliates of both Kayne Anderson Capital Advisors and Vulcan Capital own interests in our general partner. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, were approximately $101 million, and were used to reduce the balance outstanding under our revolving credit facilities. The Class C common units were unlisted securities that are *pari passu* in voting and distribution rights with the Partnership's publicly traded common units. The Class C common units were similar in most respects to the Partnership's Class B common units. Both classes became convertible on a one-for-one basis into common units upon approval by the holders of a majority of the common units at a special meeting of our unitholders held on January 20, 2005. All of the Class B common units and Class C common units converted in February 2005.

Payment of Deferred Acquisition Price

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 that date. The liability was satisfied on April 30, 2004 with the issuance of approximately 385,000 common units and the payment of $6.5 million in cash. 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, an incremental $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.

Note 7—Derivatives and Financial Instruments

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 December 31, 2004, balance sheet includes assets of $63.9 million ($55.2 million current), liabilities of $29.5 million ($18.9 million current) and unrealized net gains deferred to Other Comprehensive Income ("OCI") of $25.9 million. Total derivative activities for the year ended December 31, 2004, generated a gain of $35.1 million. This gain includes (i) derivatives that do not qualify for hedge accounting (a gain of approximately $0.9 million), (ii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items (a gain of approximately $0.1 million), and (iii) gains and losses recognized in earnings for all hedges settled during the period (a net gain of approximately $34.1 million). The majority of these gains are related to our commodity price risk hedging activities that are offset by physical transactions, as discussed below.

As of December 31, 2004, the total amount of deferred net gains 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 year ended December 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 $25.9 million net gain deferred in OCI at December 31, 2004, a net gain of $34.7 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). Since 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.

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 we use 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," as amended, these derivative instruments are recognized in the balance sheet or earnings at their fair values. 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 into OCI and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

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.

Interest Rate Risk Hedging

At December 31, 2004, we have no open interest rate hedging instruments. However, there are approximately $6.1 million deferred in OCI that relates to cash flow hedge instruments that were terminated and cash settled ($1.4 million related to an instrument settled in 2004 and $4.7 million related to instruments settled in 2003) that relate to debt agreements refinanced in 2004 and 2003, respectively. The deferred loss related to these instruments is being amortized into interest expense over the original terms of the terminated instruments (approximately $2.9 million over the next two years and the remaining $3.2 million over approximately ten years). Approximately $1.5 million related to the terminated instruments were reclassified into interest expense during 2004. In addition, earnings for 2004 include a loss of approximately $0.7 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 and, at times, a portion of our debt is denominated in Canadian dollars, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

At December 31, 2004, we had forward exchange contracts that allow us to exchange Canadian dollars for U.S. dollars, quarterly, at set exchange rates as detailed below:

	Canadian Dollars	US Dollars	Rate
	($ in millions)		
2005	$3.0	$2.3	1.33 to 1
2006	$2.0	$1.5	1.32 to 1

In addition, at December 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $21.0 million, effectively converting this amount of our U.S. dollar denominated debt to $32.5 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 will reduce by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2004, $9.9 million of our long-term debt was denominated in Canadian dollars ($11.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.20 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

Fair Value of Financial Instruments

The carrying amounts and fair values of our financial instruments are as follows (in millions):

	December 31,			
	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$42.3	$42.3	$7.5	$7.5
Options and swaps	$(2.8)	$(2.8)	$(3.3)	$(3.3)
Forward exchange contracts	$(1.5)	$(1.5)	$(0.4)	$(0.4)
Cross currency swaps	$(6.3)	$(6.3)	$(4.8)	$(4.8)
Interest rate swaps	$—	$—	$(0.4)	$(0.4)
Short and long-term debt under credit facilities	$231.8	$231.8	$95.3	$95.3
Borrowings under senior secured hedged inventory facility	$80.4	$80.4	$100.5	$100.5
Senior notes	$797.3	$848.0	$449.0	$482.9

As of December 31, 2004 and 2003, the carrying amounts of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments. The carrying amounts of the variable rate instruments in our credit facilities and senior secured hedged inventory facility approximate fair value primarily because the interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market. The interest rate on our senior notes (7.75%, 5.88%, 5.63%, and 4.75%) is fixed and the fair value is based on quoted market prices.

The carrying amount of our derivative financial instruments approximate fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments include cross currency swaps, forward exchange and extra option contracts, interest rate swap, collar and treasury lock agreements for which fair values are based on current liquidation values. We also have over-the-counter option and swap contracts for which fair values are estimated based on various sources such as independent reporting services, industry publications and brokers. For positions where independent quotations are not available, an estimate is provided, or the prevailing market price at which the positions could be liquidated is used. In addition, we have NYMEX futures and options for which the fair values are based on quoted market prices.

Note 8—Major Customers and Concentration of Credit Risk

Marathon Ashland Petroleum ("MAP") accounted for 10%, 12% and 10% of our revenues for each of the three years in the period ended December 31, 2004. BP Oil Supply also accounted for 10% of our revenues for the year ended December 31, 2004. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from MAP and BP Oil Supply pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered credit worthy, unless the credit risk can otherwise be reduced.

Note 9—Related Party Transactions

Reimbursement of Expenses of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner for the years ended December 31, 2004, 2003 and 2002 were approximately $151.0 million, $88.1 million and $70.8 million, respectively.

Crude Oil Marketing Agreement

As of December 31, 2004, Vulcan Energy, through its wholly-owned subsidiary Plains Resources, owned an effective 44% of our general partner interest, as well as approximately 18.3% of our outstanding limited partner units. We are the exclusive marketer/purchaser for all of Plains Resources' and its subsidiaries' equity crude oil production. We have a marketing agreement with Plains Resources (the "Marketing Agreement") whereby we will purchase for resale at market prices the majority of Plains Resources' crude oil production for which we charge a fee of $0.20 per barrel. This fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2004, 2003 and 2002, we paid Plains Resources approximately $28.3 million, $25.7 million and $247.7 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $0.1 million, $0.2 million and $1.8 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In connection with the separation of Plains Resources and one of its subsidiaries, discussed below, Plains Resources divested the bulk of its producing properties. As a result, we do not anticipate the marketing arrangement with Plains Resources to be material to our operating results in the future. As currently in effect, the Marketing Agreement will terminate upon a "change of control" of Plains Resources or our general partner. The recent purchase of Plains Resources by Vulcan Energy would have constituted a change of control under the Marketing Agreement. In July 2004, we amended and restated the Marketing Agreement to exclude the Vulcan transaction from the change of control provisions.

In December 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production Company ("PXP") to its shareholders. PXP is a successor participant to the Marketing Agreement. For the years ended December 31, 2004 and 2003, we paid PXP approximately $328.3 million and $277.9 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production and recognized margins of approximately $1.4 and $1.7 million, respectively, from the marketing fee. In our opinion, these purchases were made at prevailing market prices. We are also party to a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. ("Tosco") terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates. In July 2004, we amended and restated the Marketing Agreement to, among other things, reflect the change in parties as a result of the spin-off. We sell PXP's crude under sales contracts that range from one year to four years in length. In October 2004, we further amended the PXP Marketing Agreement to exclude any newly acquired properties and to adjust the marketing fee to $0.15 per barrel for any new contracts entered into after January 1, 2005.

Due to Related Parties

The balance of amounts due to related parties at December 31, 2004 and 2003 was $32.9 million and $27.0 million, respectively, and was primarily related to crude oil purchased by us but not yet paid as of December 31 of each year.

Performance Option Plan

In connection with the transfer of a majority of our general partner interest in 2001, the owners of the general partner (other than PAA Management, L.P.) contributed an aggregate of 450,000 subordinated units (now converted into common units) to the general partner to provide a pool of units available for the grant of options to management and key employees. In that regard, the general partner adopted the Plains All American 2001 Performance Option Plan, pursuant to which options to purchase approximately 391,000 units have been granted. These options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached, and 25% of the options vested, in 2002. The second level was reached, and an additional 25% of the options vested, in 2004. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The exercise price under the options was $22 per unit at the time of grant, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2004, the exercise price was $15.91 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options. At December 31, 2004 approximately 388,000 units were outstanding.

Benefit Plan

Our general partner maintains a 401(k) defined contribution plan whereby it matches 100% of an employee's contribution (subject to certain limitations in the plan). For the years ended December 31, 2004, 2003 and 2002, the defined contribution plan matching expense was approximately $4.0 million, $2.6 million and $2.1 million, respectively. Similarly, PMC (Nova Scotia) Company maintains a group Registered Savings Plan and a Non Registered Employee Savings Plan for our Canadian employees. For the years ended December 31, 2004, 2003 and 2002, these plans had expense of approximately $1.0 million, $0.7 million and $0.4 million, respectively.

Note 10—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 LTIP") for employees and directors of our general partner and its affiliates who perform services for us. Awards contemplated by the 1998 LTIP include phantom units and unit options. The 1998 LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors has the right to alter or amend the 1998 LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

A phantom unit entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). As of December 31, 2004, aggregate outstanding grants of approximately 134,000 units have been made to employees, officers and directors of our general partner. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine.

Common units to be delivered upon the vesting of grants may be common units acquired by our general partner in the open market or in private transactions, common units already owned by our general partner, or any combination of the foregoing. Our general partner will be entitled to reimbursement by us for the cost incurred in acquiring common units and any other costs incurred in settling obligations under the 1998 LTIP. In addition, the Partnership may issue up to 975,000 new common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights ("DERs") with respect to phantom units. A DER entitles the grantee to a cash payment, either while the award is outstanding or upon vesting, equal to any cash distributions paid on a unit while the award is outstanding. There are no tandem equivalent distribution rights outstanding at this time under the 1998 LTIP.

Other than grants to directors, none of the phantom units vested until November 2003. Since that time, approximately 927,000 phantom units have vested. Including grants to directors, approximately 418,000 units have been purchased and delivered or issued in satisfaction of vesting, after payment of cash-equivalents and netting for taxes. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under our 1998 LTIP will vest. As a result, we recognized an expense of approximately $7.9 million and $28.8 million for the years ended December 31, 2004 and 2003, respectively.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units.

Our 1998 LTIP currently permits the grant of options to purchase common units. No unit option grants have been made under the 1998 LTIP to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

In January 2005, our unitholders approved the 2005 Long-Term Incentive Plan (the "2005 LTIP"). The 2005 LTIP provides for awards to our employees and directors. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the Compensation Committee (each an "Award"). Up to 3,000,000 units may be issued in satisfaction of Awards. Certain Awards may also include DERs in the discretion of the Compensation Committee. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the 2005 LTIP. Certain of these Awards could be considered a common stock equivalent and thus be dilutive to our earnings per unit from the time of their date of grant. In February 2005, our Board of Directors and Compensation Committee approved grants of approximately 1,900,000 phantom units (a substantial number of which include DERs) under the 2005 LTIP.

The issuance of the common units upon vesting of phantom units is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration is paid to us by the plan participants upon vesting and delivery of the common units.

Note 11—Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating and capital leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancellable commitments related to these items at December 31, 2004, are summarized below (in millions):

2005	$17.8
2006	$14.0
2007	$10.9
2008	$6.3
2009	$5.2
Thereafter	$13.7

Expenditures related to leases for 2004, 2003 and 2002 were $20.1 million, $13.4 million and $9.7 million, respectively.

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer 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. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled Alfons Sperber v. Plains Resources Inc., et al. This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unitholders, asserted breach of fiduciary duty and breach of contract claims against us, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint sought to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. This lawsuit has been settled in principle. The court has approved the settlement and, assuming no appeals are filed, the settlement will become final in March 2005.

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

Note 12—Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. As such, we could be required to remove or remediate hazardous liquids or associated generated wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination.

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In addition, we have entered into indemnification agreements with various counterparties in conjunction with several of our acquisitions. Allocation of environmental liability is an issue negotiated in connection with each of our acquisition transactions. In each case, we make an assessment of potential environmental exposure based on available information. Based on that assessment and relevant economic and risk factors, we determine whether to negotiate an indemnity, what the terms of any indemnity should be (for example, minimum thresholds or caps on exposure) and whether to obtain insurance, if available. In some cases, we have received contractual protections in the form of environmental indemnifications from several predecessor operators for properties acquired by us that are contaminated as a result of historical operations. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply and have term and total dollar limits.

The acquisitions we completed in 2003 and 2004 include a variety of provisions dealing with the allocation of responsibility for environmental costs that range from no or limited indemnities from the sellers to indemnification from sellers with defined limitations on their maximum exposure. We have not obtained insurance for any of the conditions related to our 2003 acquisitions, and only in limited circumstances for our 2004 acquisitions.

For instance, in connection with the Link acquisition, we identified a number of environmental liabilities for which we received a purchase price reduction from Link. A substantial portion of these environmental liabilities are associated with the former Texas New Mexico ("TNM") pipeline assets. On the effective date of the acquisition, we and TNM entered into a cost-sharing agreement whereby, on a tiered basis, we will bear $11 million of the first $20 million of pre-May 1999 environmental issues. We will also bear the first $25,000 per site for new sites which were not identified at the time we entered into the agreement (capped at 100 sites). TNM will pay all costs in excess of $20 million (excluding the deductible for new sites). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). We recorded a reserve for environmental liabilities of approximately $17.0 million in connection with the Link acquisition.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, Shell purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012. Shell has recently made a claim against the policy; however, we do not believe that the claim will substantially reduce our coverage under the policy.

In connection with our 1999 acquisition of Scurlock Permian LLC from MAP, we were indemnified by MAP for any environmental liabilities attributable to Scurlock's business or properties which occurred prior to the date of the closing of the acquisition. This indemnity applied to claims that exceeded $25,000 individually and $1.0 million in the aggregate. For the indemnity to apply, we were required to assert any claims on or before May 15, 2003. In conjunction with the expiration of this indemnity, we reached agreement with respect to MAP's remaining indemnity obligations. Under the terms of this agreement, MAP will continue to remain obligated for liabilities associated with two Superfund sites at which it is alleged that Scurlock Permian deposited waste oils. In addition, MAP paid us $4.6 million cash as satisfaction of its obligations with respect to other sites. During 2002, we had reassessed previous investigations and completed environmental studies related to environmental conditions associated with our 1999 acquisitions. As a result of that reassessment, we established an additional reserve of $1.2 million.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified. We have in the past experienced and in the future will likely experience releases of crude oil into the environment from our pipeline and storage operations, or discover releases that were previously unidentified. Although we maintain a program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to environmental releases from our assets may substantially affect our business.

At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million (approximately $12.7 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $9.3 million of our environmental reserve is classified as current and $10.5 million is classified as long-term. At December 31, 2004, we have recorded receivables totaling approximately $6.3 million for amounts recoverable under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. We believe that this reserve is adequate, and in conjunction with our indemnification arrangements, should prevent remediation costs from having a material adverse effect on our financial condition, results of operations, or cash flows. Our estimates used in these reserves are based on all known facts at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, no assurances can be made that any costs incurred in excess of this reserve or outside of the indemnifications would not have a material adverse effect on our financial condition, results of operations, or cash flows.

Note 13—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total(1)
	(in thousands, except per unit data)				
2004					
Revenues(3)	$3,804.6	$5,131.7	$5,867.0	$6,172.1	$20,975.5
Gross margin	59.7	64.8	74.0	65.7	264.2
Operating income	40.5	45.2	55.1	39.2	180.0
Income before cumulative effect of change in accounting principle	31.0	35.7	41.7	24.7	133.1
Net income	27.9	35.7	41.7	24.7	130.0
Basic and diluted income per limited partner unit before cumulative effect of change in accounting principle	0.49	0.54	0.59	0.32	1.94
Basic and diluted net income per limited partner unit	0.44	0.54	0.59	0.32	1.89
Cash distributions per common unit(2)	$0.563	$0.563	$0.578	$0.600	$2.30
2003					
Revenues(3)	$3,281.9	$2,709.2	$3,053.7	$3,545.0	$12,589.8
Gross margin	46.7	44.0	38.7	41.2	170.6
Operating income	33.6	31.9	21.0	11.6	98.2
Net income (loss)	24.4	23.4	11.9	(0.2)	59.4
Basic net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.01
Diluted net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.00
Cash distributions per common unit(2)	$0.538	$0.550	$0.550	$0.550	$2.19

(1) The sum of the four quarters does not equal the total year due to rounding.

(2) Distributions represent those declared and paid in the applicable period.

(3) Includes buy/sell transactions, see Note 2.

Note 14—Operating Segments

Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. 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 results of operations and cash flow. 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 evaluate segment performance based on segment profit and 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. The following table reflects certain financial data for each segment for the periods indicated (note that each of the items in the following table excludes depreciation and amortization):

	Pipeline	GMT&S	Total
		(in millions)	
Twelve Months Ended December 31, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $149.8, $11,247.0, and $11,396.8, respectively)	$752.9	$20,222.6	$20,975.5
Intersegment[a]	122.0	0.9	122.9
Total revenues of reportable segments	$874.9	$20,223.5	$21,098.4
Segment profit[c]	$157.2	$91.5	$248.7
Capital expenditures	$520.7	$131.5	$652.2
Total assets	$1,507.5	$1,652.9	$3,160.4
Non-cash SFAS 133 impact[b]	$—	$1.0	$1.0
Maintenance capital	$8.3	$3.0	$11.3
Twelve Months Ended December 31, 2003			
Revenues:			
External Customers (includes buy/sell revenues of $166.2, $6,124.9, and $6,291.1, respectively)	$605.1	$11,984.7	$12,589.8
Intersegment[a]	53.5	0.9	54.4
Total revenues of reportable segments	$658.6	$11,985.6	$12,644.2
Segment profit[c]	$81.3	$63.1	$144.4
Capital expenditures	$211.9	$21.9	$233.8
Total assets	$1,221.0	$874.6	$2,095.6
Non-cash SFAS 133 impact[b]	$—	$0.4	$0.4
Maintenance capital	$6.4	$1.2	$7.6
Twelve Months Ended December 31, 2002			
Revenues:			
External Customers (includes buy/sell revenues of $95.8, $4,140.8, and $4,236.7, respectively)	$462.4	$7,921.8	$8,384.2
Intersegment[a]	23.8	—	23.8
Total revenues of reportable segments	$486.2	$7,921.8	$8,408.0
Segment profit[c]	$70.7	$58.9	$129.6
Capital expenditures	$341.9	$23.3	$365.2
Non-cash SFAS 133 impact[b]	$—	$0.3	$0.3
Maintenance capital	$3.4	$2.6	$6.0

Table continued on following page

(a) Intersegment sales were conducted at arms length.

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

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

	Year ended December 31,		
	2004	2003	2002
Segment profit	$248.7	$144.4	$129.6
Unallocated general and administrative expenses	—	—	(1.0)
Depreciation and amortization	(67.2)	(46.8)	(34.1)
Gain on sale of assets	0.6	0.6	—
Impairment loss	(2.0)	—	—
Interest expense	(46.7)	(35.2)	(29.1)
Interest income and other, net	(0.3)	(3.6)	(0.1)
Income before cumulative effect of change in accounting principle	$133.1	$59.4	$65.3

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long lived assets attributable to these geographic areas (in millions):

	For the Year Ended December 31,		
Revenues	2004	2003	2002
United States (includes buy/sell revenues of $10,164.6, $5,621.6, and $3,715.5, respectively)	$17,499.5	$10,536.8	$6,941.7
Canada (includes buy/sell revenues of $1,232.2, $669.5, and $521.2, respectively)	3,476.0	2,053.0	1,442.5
	$20,975.5	$12,589.8	$8,384.2

	For the Year Ended December 31,	
Long-Lived Assets	2004	2003
United States	$1,670.8	$1,039.8
Canada	379.7	316.9
	$2,050.5	$1,356.7

Note 15—Subsequent Event

On February 25, 2005, we issued 575,000 common units to a subsidiary of Vulcan Energy Corporation. The sale price for the common units was $38.13 per unit resulting in net proceeds, including the general partner's proportionate capital contribution and expenses associated with the sale, of approximately $22.3 million. We intend to use the net proceeds from the private placement to fund a portion of our 2005 expansion capital program. Pending the incurrence of such expenditures, the net proceeds will be used to repay indebtedness under our revolving credit facilities.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

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

By: PLAINS ALL AMERICAN GP LLC,
its general partner

Date: March 2, 2005

By: ______________________________

Greg L. Armstrong, Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

Date: March 2, 2005

By: ______________________________

Phillip D. Kramer, Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	Date: March 2, 2005
Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	Date: March 2, 2005
Phillip D. Kramer	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	Date: March 2, 2005
Tina L. Val	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	Date: March 2, 2005
Everardo Goyanes	Director of Plains All American GP LLC	Date: March 2, 2005
Gary R. Petersen	Director of Plains All American GP LLC	Date: March 2, 2005
John T. Raymond	Director of Plains All American GP LLC	Date: March 2, 2005
Robert V. Sinnott	Director of Plains All American GP LLC	Date: March 2, 2005
David N. Capobianco	Director of Plains All American GP LLC	Date: March 2, 2005
Arthur L. Smith	Director of Plains All American GP LLC	Date: March 2, 2005
J. Taft Symonds	Director of Plains All American GP LLC	Date: March 2, 2005

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2005

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PLAINS ALL AMERICAN PIPELINE, L.P.

I, Phil Kramer, certify that:

1. I have reviewed this annual report on Form 10-K of Plains All American Pipeline, L.P.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end the period covered by this report based on such evaluation; and

(d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 2, 2005

Phil Kramer
Chief Financial Officer

EXHIBIT 32.1

CERTIFICATION OF
CHIEF EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. § 1350

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K for the period ending December 31, 2004 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Name: Greg L. Armstrong
Date: March 2, 2005

EXHIBIT 32.2

CERTIFICATION OF
CHIEF FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. § 1350

I, Phil Kramer, Chief Financial Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-K for the period ending December 31, 2004 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Name: Phil Kramer
Date: March 2, 2005