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 quarter ended March 31, 2004)
3.2	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.3	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
3.4	—	Certificate of Incorporation of PAA Finance Corp. (incorporated by reference to Exhibit 3.6 to the Registration Statement on Form S-3 filed August 27, 2001)
3.5	—	Bylaws of PAA Finance Corp. (incorporated by reference to Exhibit 3.7 to the Registration Statement on Form S-3 filed August 27, 2001)
3.6	—	Second Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC, dated September 12, 2005 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 16, 2005)
3.7	—	Second Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated September 12, 2005 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed September 16, 2005)
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002)
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003)

4.4	—	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.4 to the Registration Statement on Form S-4, File No. 333-121168)
4.5	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168)
4.6	—	Class C Common Unit Purchase Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners, L.P., Kayne Anderson MLP Fund, L.L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated March 31, 2004 (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
4.7	—	Registration Rights Agreement by and among Plains All American Pipeline, L.P., Kayne Anderson Energy Fund II, L.P., KAFU Holdings, L.P., Kayne Anderson Capital Income Partners (QP), L.P., Kayne Anderson MLP Fund, L.P., Tortoise Energy Infrastructure Corporation and Vulcan Energy II Inc. dated April 15, 2004 (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004)
4.8	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005)
10.1	—	Amended and Restated Credit Agreement dated November 4, 2005 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 quarter ended September 30, 2005)
10.2	—	Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 24, 2004)
10.3	—	Amended and Restated Crude Oil 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 quarter 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 quarter 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 the Current Report on 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 the Current Report on 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 the Current Report on 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 the Current Report on Form 8-K filed June 11, 2001)
10.9**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005.)
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 the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003)
10.11**	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the 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 10.1 to the 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 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001)
10.14	—	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on 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 the Registration Statement on Form S-1, File No. 333-64107)
10.16	—	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1, 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 the 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 the 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 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998)
10.20**	—	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004)
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 the Annual Report on Form 10-K for the year ended December 31, 2001)

10.24**+	—	Form of LTIP Grant Letter (Armstrong/Pefanis)
10.25**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005)
10.26**	—	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the 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 the 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 the Current Report on Form 8-K filed February 23, 2005)
10.29**	—	Form of Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005)
10.30	—	Administrative Services Agreement between Plains All American Pipeline Company and Vulcan Energy Corporation, dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005)
10.31	—	Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC, dated September 13, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed September 19, 2005)
10.32	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC, dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005)
10.33**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005)
10.34**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16, 2005)
10.35	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005)
10.36	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005)
10.37	—	First Amendment dated as of April 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 21, 2005)
10.38	—	Second Amendment dated as of May 20, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 12, 2005)
10.39**+	—	Form of LTIP Grant Letter (executive officers)
10.40**+	—	Employment Agreement between Plains All American GP LLC and John vonBerg dated December 18, 2001
10.41+	—	Third Amendment dated as of November 4, 2005 to Restated Credit Agreement, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto
21.1+	—	List of Subsidiaries of Plains All American Pipeline, L.P.

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

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

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 Partnership’s internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership’s internal control over financial reporting was effective as of December 31, 2005. Management’s assessment of the effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2005 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, 2006

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

We have completed integrated audits of Plains All American Pipeline, L.P.'s 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005, and an audit of its 2003 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 present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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, 2005 based on criteria established in Internal Control- Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2005, 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 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, 2006

CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$	$ 1
Trade accounts receivable and other receivables, net	781.0	521.8
Inventory	910.3	498.2
Other current assets	104.3	68.2
Total current assets	1,805.2	1,101.2
PROPERTY AND EQUIPMENT	2,116.1	1,911.5
Accumulated depreciation	(258.9)	(183.9)
	1,857.2	1,727.6
OTHER ASSETS		
Pipeline linefill in owned assets	180.2	168.4
Inventory in third party assets	71.5	59.3
Investment in PAA/Vulcan Gas Storage, LLC	113.5	—
Other, net	92.7	103.9
Total assets	$4,120.3	$3,160.4
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$1,293.6	$ 850
Due to related parties	6.8	32.9
Short-term debt	378.4	175.5
Other current liabilities	114.5	54.4
Total current liabilities	1,793.3	1,113.7
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	4.7	151.7
Senior notes, net of unamortized discount of $3.1 and $2.7, respectively	947.0	797.3
Other long-term liabilities and deferred credits	44.6	27.5
Total liabilities	2,789.6	2,090.2
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Common unitholders (73,768,576 and 62,740,218 units outstanding at December 31, 2005, and December 31, 2004, respectively)	1,294.1	919.8
Class B common unitholder (1,307,190 units outstanding at December 31, 2004)	—	18.8
Class C common unitholders (3,245,700 units outstanding at December 31, 2004)	—	100.4
General partner	36.6	31.2
Total partners' capital	1,330.7	1,070.2
	$4,120.3	$3,160.4

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

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Twelve Months Ended December 31, 2005	2004	2003
REVENUES			
Crude oil and LPG sales (includes approximately $16,077.8, $11,247.0, $6,124.9, respectively, related to buy/sell transactions, see Note 2)	$30,139.7	$20,184.3	$11,952.6
Other gathering, marketing, terminalling and storage revenues	46.0	38.4	32.1
Pipeline margin activities revenues (includes approximately $197.1, $149.8, and $166.2, respectively, related to buy/sell transactions, see Note 2)	772.7	575.2	505.3
Pipeline tariff activities revenues	218.9	177.6	99.9
Total revenues	31,177.3	20,975.5	12,589.9
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs (includes approximately $15,910.3, $11,137.7 and $5,967.2, respectively, related to buy/sell transactions, see Note 2)	29,691.9	19,870.9	11,746.4
Pipeline margin activities purchases (includes approximately $196.2, $142.5 and $159.2, respectively, related to buy/sell transactions, see Note 2)	750.6	553.7	486.1
Field operating costs (excluding Long-Term Incentive Plan (“LTIP”) charge)	269.4	218.6	134.2
LTIP charge—operations	3.1	0.9	5.7
General and administrative expenses (excluding LTIP charge)	80.2	75.7	50.0
LTIP charge—general and administrative	23.0	7.0	23.1
Depreciation and amortization	83.5	68.7	46.2
Total costs and expenses	30,901.7	20,795.5	12,491.7
OPERATING INCOME	275.6	180.0	98.2
OTHER INCOME/(EXPENSE)			
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.0	—	—
Interest expense (net of capitalized interest of $1.8, $0.5, and $0.5)	(59.4)	(46.7)	(35.2)
Interest and other income (expense), net	0.6	(0.2)	(3.6)
Income before cumulative effect of change in accounting principle	217.8	133.1	59.4
Cumulative effect of change in accounting principle	—	(3.1)	—
NET INCOME	$ 21	$ 13	$
NET INCOME-LIMITED PARTNERS	$ 19	$ 11	$
NET INCOME-GENERAL PARTNER	$	$	$
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$	$	$
Cumulative effect of change in accounting principle	—	(0.05)	—
Net income	$	$	$
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$	$	$
Cumulative effect of change in accounting principle	—	(0.05)	—
Net income	$	$	$
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	69.3	63.3	52.7
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	70.5	63.3	53.4

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year Ended December 31,		
	2005	**2004**	**2003**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 217.[illegible]	$ 130.[illegible]	$ 59[illegible]
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	83.5	68.7	46.2
Cumulative effect of change in accounting principle	—	3.1	—
Inventory valuation adjustment	—	2.0	—
SFAS 133 mark-to-market adjustment	18.9	(1.0)	(0.4)
LTIP charge	26.1	7.9	28.8
Noncash amortization of terminated interest rate hedging instruments	1.6	1.5	—
(Gain)/loss on foreign currency revaluation	2.1	(5.0)	—
Net cash paid for terminated interest rate hedging instruments	(0.9)	(1.5)	(6.2)
Equity earnings in PAA/Vulcan Gas Storage, LLC	(1.0)	—	—
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(299.2)	(29.2)	(98.3)
Inventory	(425.1)	(398.7)	(38.9)
Accounts payable and other current liabilities	427.8	327.5	121.3
Inventory in third party assets	—	(7.2)	—
Due to related parties	(27.5)	5.9	3.4
Net cash provided by operating activities	24.1	104.0	115.3
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions	(30.0)	(535.3)	(168.4)
Additions to property and equipment	(164.1)	(116.9)	(65.4)
Investment in PAA/Vulcan Gas Storage, LLC	(112.5)	—	—
Cash paid for linefill in assets owned	—	(2.0)	(46.8)
Proceeds from sales of assets	9.4	3.0	8.5
Net cash used in investing activities	(297.2)	(651.2)	(272.1)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on long-term revolving credit facility	(143.7)	64.9	62.5
Net borrowings on working capital revolving credit facility	67.2	62.9	25.3
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	138.9	(20.1)	(6.2)
Principal payments on senior secured term loans	—	—	(297.0)
Proceeds from the issuance of senior notes	149.3	348.1	249.3
Net proceeds from the issuance of common units	264.2	262.1	250.3
Distributions paid to unitholders and general partner	(197.0)	(158.4)	(121.8)
Other financing activities	(8.3)	(5.0)	(5.2)
Net cash provided by financing activities	270.6	554.5	157.2
Effect of translation adjustment on cash	(0.9)	1.6	0.2
Net increase/(decrease) in cash and cash equivalents	(3.4)	8.9	0.6
Cash and cash equivalents, beginning of period	13.0	4.1	3.5
Cash and cash equivalents, end of period	$	$ 13[illegible]	$
Cash paid for interest, net of amounts capitalized	$ 80[illegible]	$ 40[illegible]	$ 36[illegible]

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL

(in millions)

	Common Units		Class B Common Units		Class C Common Units		Subordinated Units		General Partner	Total	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Amount	Units	Amount
Balance at December 31, 2002	38.3	$ 524	1.3	$ 18.5	—	$	10.0	$(47.1)	$ 15.8	49.6	$ 511
Net income	—	41.3	—	1.3	—	—	—	10.8	6.0	—	59.4
Distributions	—	(89.8)	—	(2.9)	—	—	—	(21.9)	(7.2)	—	(121.8)
Issuance of common units	8.7	245.1	—	—	—	—	—	—	5.2	8.7	250.3
Issuance of common units under LTIP	—	0.6	—	—	—	—	—	—	—	—	0.6
Conversion of subordinated units	2.5	(9.8)	—	—	—	—	(2.5)	9.8	—	—	—
Other comprensive income	—	32.3	—	1.1	—	—	—	8.5	4.7	—	46.6
Balance at December 31, 2003	**49.5**	**$ 744**	**1.3**	**$ 18.0**	**—**	**$**	**7.5**	**$(39.9)**	**$ 24.5**	**58.3**	**$ 746**
Net income	—	111.1	—	2.5	—	4.2	—	1.5	10.7	—	130.0
Distributions	—	(134.2)	—	(3.0)	—	(5.7)	—	(4.2)	(11.3)	—	(158.4)
Issuance of common units	5.0	157.5	—	—	—	—	—	—	3.4	5.0	160.9
Issuance of common units under LTIP	0.4	11.8	—	—	—	—	—	—	0.2	0.4	12.0
Issuance of units for acquisition contingent consideration	0.4	13.1	—	—	—	—	—	—	0.3	0.4	13.4
Private placement of Class C common units	—	—	—	—	3.2	98.8	—	—	2.1	3.2	100.9
Other comprehensive income	—	59.9	—	1.3	—	3.1	—	(0.9)	1.3	—	64.7
Conversion of subordinated units	7.5	(43.5)	—	—	—	—	(7.5)	43.5	—	—	—
Balance at December 31, 2004	**62.8**	**$ 919**	**1.3**	**$ 18.8**	**3.2**	**$100.4**	**—**	**$**	**$ 31.2**	**67.3**	**$1,070.2**
Net income	—	196.9	—	0.5	—	1.4	—	—	19.0	—	217.8
Distributions	—	(175.6)	—	(0.8)	—	(2.0)	—	—	(18.6)	—	(197.0)
Issuance of common units	6.5	258.7	—	—	—	—	—	—	5.5	6.5	264.2
Issuance of common units under LTIP	—	1.9	—	—	—	—	—	—	—	—	1.9
Conversion of Class B units	1.3	18.3	(1.3)	(18.3)	—	—	—	—	—	—	—
Conversion of Class C units	3.2	99.3	—	—	(3.2)	(99.3)	—	—	—	—	—
Other comprehensive loss		(25.2)		(0.2)		(0.5)	—	—	(0.5)	—	(26.4)
Balance at December 31, 2005	**73.8**	**$1,294.1**	**—**	**$**	**—**	**$**	**—**	**$**	**$ 36.0**	**73.8**	**$1,330.7**

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Twelve Months Ended December 31,		
	2005	2004	2003
		(in millions)	
Net income	$217.8	$130.0	$ 59.
Other comprehensive income/(loss)	(26.4)	64.7	46.6
Comprehensive income	$191.4	$194.7	$106.0

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(in millions)	
Balance at December 31, 2002	$ (8)	$ (6.2)	$ (14.)
Reclassification adjustments for settled contracts	(28.2)	—	(28.2)
Changes in fair value of outstanding hedge positions	28.7	—	28.7
Currency translation adjustment	—	46.1	46.1
2003 Activity	0.5	46.1	46.6
Balance at December 31, 2003	$ (7)	$39.9	$ 32
Reclassification adjustments for settled contracts	13.2	—	13.2
Changes in fair value of outstanding hedge positions	20.4	—	20.4
Currency translation adjustment	—	31.1	31.1
2004 Activity	33.6	31.1	64.7
Balance at December 31, 2004	$ 25	$71.0	$ 96
Reclassification adjustments for settled contracts	117.4	—	117.4
Changes in fair value of outstanding hedge positions	(159.9)	—	(159.9)
Currency translation adjustment	—	16.1	16.1
2005 Activity	(42.5)	16.1	(26.4)
Balance at December 31, 2005	$ (16.)	$87.1	$ 70

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

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 domestic officers and personnel. Our Canadian officers and employees are employed by PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. 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 54.3% to 1.2%. Also, see Note 8 for a description of the reallocation of the General Partnership interest.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2005 and 2004, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2005, 2004 and 2003. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the previous years to conform to the 2005 presentation of the financial statements. These reclassifications do not affect net income. 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 we have 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 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 did not include linefill barrels in the same average costing calculation as our operating inventory, but instead carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we 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 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. 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.

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, ("SFAS 133") (iii) contingent liability accruals, (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets and (v) accruals related to our Long-Term Incentive Plans. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

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 delivery of the product to the purchaser or its designee. 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. See "—Recent Accounting Pronouncements" below.

Terminalling and storage revenues, which are classified as other GMT&S 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 in 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 or third party terminal. 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 delivery of the product to the purchaser or its designee. 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; (iii) interest cost attributable to borrowings for inventory stored in a contango market; (iv) performance related bonus accruals; and (v) expenses of issuing 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, payroll and benefit 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. The foreign currency transactions resulted in a loss of approximately $2.1 million and a gain of approximately $5.0 million for the years ended December 31, 2005 and 2004, respectively. There was no material gain or loss for the year ended December 31, 2003.

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 the 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. 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 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, 2005 and 2004, we had received approximately $52.5 million and $20.3 million, respectively, of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At December 31, 2005 and 2004, 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 $0.8 million and $0.6 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,		
	2005	2004	2003
Balance at beginning of year	$ 0.6	$0.2	$ 8.1
Applied to accounts receivable balances	(0.7)	—	(8.3)
Charged to expense	0.9	0.4	0.4
Balance at end of year	$ 0.8	$0.6	$ 0.2

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, 2005 and 2004, inventory and linefill consisted of:

	December 31, 2005			December 31, 2004		
	Barrels	Dollars	Dollar/ barrel	Barrels	Dollars	Dollar/ barrel
	(Barrels in thousands and dollars in millions)					
Inventory[1]						
Crude oil	13,887	$ 755	$54.42	8,716	$396.2	$45.46
LPG	3,649	149.0	$40.83	2,857	100.1	$35.04
Parts and supplies	N/A	5.6	N/A	N/A	1.9	N/A
Inventory subtotal	17,536	910.3		11,573	498.2	
Inventory in third party assets						
Crude oil	1,248	58.6	$46.96	1,294	48.7	$37.64
LPG	318	12.9	$40.57	318	10.6	$33.33
Inventory in third party assets subtotal	1,566	71.5		1,612	59.3	
Linefill						
Crude oil linefill	6,207	179.3	$28.89	6,015	168.4	$28.00
LPG linefill	27	0.9	$33.33	—	—	N/A
Linefill subtotal	6,234	180.2		6,015	168.4	
Total	25,336	$1,162.0		19,200	$725.9	

(1) Dollars per barrel include the impact of inventory hedges on a portion of our volumes.

Property and Equipment

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

	Estimated Useful Lives (Years)	December 31, 2005	2004
		(in millions)	
Crude oil pipelines and facilities	30 - 40	$1,739.5	$1,605.3
Crude oil and LPG storage and terminal facilities	30 - 40	214.6	169.6
Trucking equipment and other	5 - 15	137.1	117.6
Office property and equipment	3 - 5	24.9	19.0
		2,116.1	1,911.5
Less accumulated depreciation		(258.9)	(183.9)
Property and equipment, net		$1,857.2	$1,727.6

Depreciation expense for each of the three years in the period ended December 31, 2005 was $79.2 million, $64.8 million and $41.8 million, respectively.

We calculate our depreciation 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. Also, gains/losses on sales of assets and asset impairments are included as a component of depreciation and amortization in the consolidated statements of operations.

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2005, 2004 and 2003, capitalized interest was $1.8 million, $0.5 million and $0.5 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 “Accounting for 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 or that we plan to take out of service and although the ultimate timing and cost to settle these obligations are not known with certainty, we can reasonably estimate the obligation. We have estimated that the fair value of these obligations is approximately $4.6 million and $2.5 million at December 31, 2005 and 2004, respectively. 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. There were no asset impairments in 2005 or 2003. In 2004, we recognized a charge of approximately $2.0 million associated with taking our pipeline in the Illinois Basin out of service. The amount of the impairment represented the remaining net book value of the idled pipeline system and is included as a component of depreciation and amortization in the consolidated statements of operations. 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, net

Other assets net of accumulated amortization consist of the following:

	December 31,	
	2005	2004
	(in millions)	
Goodwill	$47.4	$ 47.
Deposit on pending acquisition	—	11.9
Debt issue costs	17.4	15.5
Other investment in unconsolidated affiliate	8.2	8.2
Fair value of derivative instruments	5.5	8.6
Intangible assets (contracts)	2.8	2.7
Other	18.5	14.0
	99.8	108.0
Less accumulated amortization	(7.1)	(4.1)
	$92.7	$103.9

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, 2005 and 2004, substantially all of our goodwill is allocated to our gathering, marketing, terminalling and storage operations ("GMT&S"). Since adoption of SFAS 142, we have 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. Fully amortized 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 $3.3 million, $5.9 million and $5.1 million in 2005, 2004 and 2003, respectively. In addition, during 2005 we wrote off approximately $1.4 million of fully amortized costs and the related accumulated amortization. During 2004 and 2003, we wrote off unamortized costs totaling approximately $0.7 million and $3.3 million.

Amortization of other assets for each of the three years in the period ended December 31, 2005, was $4.3 million, $3.9 million and $4.4 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 circumstance, 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 June 2005, the Emerging Issues Task Force issued Issue No. 04-05 (“EITF 04-05”), “Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights.” EITF 04-05 provides guidance in determining whether a general partner controls a limited partnership by determining the limited partners’ substantive ability to dissolve (liquidate) the limited partnership as well as assessing the substantive participating rights of the limited partners within the limited partnership. EITF 04-05 states that if the limited partners do not have substantive ability to dissolve (liquidate) or have substantive participating rights then the general partner is presumed to control that partnership and would be required to consolidate the limited partnership. This EITF is effective in fiscal periods beginning after December 15, 2005. Although this EITF does not directly impact us, it does impact our general partner. Our general partner will adopt this standard prospectively beginning January, 1, 2006. The adoption of this standard will result in the consolidation of our results of operations and balance sheet in their consolidated financial statements.

In December 2004, the Financial Accounting Standards Board (“FASB”) issued SFAS No. 123(R) (revised 2004), “Share-Based Payment.” This statement amends SFAS No. 123, “Accounting for Stock-Based Compensation,” and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from all share-based payment transactions be recognized in the financial statements at fair value. In April 2005, both the FASB and the Securities and Exchange Commission decided to delay the effective date for public companies to implement SFAS No. 123(R). The new statement is now effective for public companies for annual periods beginning after June 15, 2005. Following our general partner’s adoption of EITF 04-05, we will be a part of the same consolidated group and thus SFAS 123(R) will be applicable to our general partner’s long-term incentive plan. Our general partner has historically followed a cash plan probability model in accounting for its long-term incentive plans and will use the modified prospective application, as defined in SFAS 123(R), to adopt this standard. Under SFAS 123(R), the obligation will be recorded at fair value. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employees and officers (See Note 8 “Related Party Transactions”), and thus the calculation of our obligation related to our general partner’s long-term incentive plan has been consistent with the methodology that they have historically used. Upon measuring the obligation at fair value under SFAS 123(R), we estimate that our obligation for outstanding awards as of January 1, 2006 will be reduced by approximately $6.4 million, which will be recorded as a cumulative effect of change in accounting principle in our consolidated statements of operations in 2006.

In September 2005, the Emerging Issues Task Force issued Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." The EITF concluded that inventory purchases and sales transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. The EITF provided indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 will be effective in reporting periods beginning after March 15, 2006. The adoption of EITF 04-13 will cause inventory purchases and sales under buy/sell transactions, which were recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statement of operations. We have parenthetically disclosed buy/sell transactions in our consolidated statements of operations. EITF 04-13 will reduce gross revenues and purchases, but is not expected to have a material impact on our financial position, net income, or liquidity. The treatment of buy/sell transactions under EITF 04-13 will reduce the relative amount of revenues on our income statement.

In 2005, the FASB issued Interpretation No. 47 ("FIN 47"), "Accounting for Conditional Asset Retirement Obligations," which is an interpretation of SFAS 143. FIN 47 defines a conditional asset retirement obligation ("ARO") as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional upon future events that may or may not be within the control of the entity. An entity is required to recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. Uncertainty about the timing and method of settlement for a conditional ARO should be considered in estimating the ARO when sufficient information exists. This Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO. We adopted FIN 47 on December 31, 2005, and the adoption did not have a material impact on our consolidated financial position or results of operations.

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. 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

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

EITF 03-06 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF 03-06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results, however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs as a larger portion of our aggregate earnings is allocated to the incentive distribution rights held by our general partner, as if distributed, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-06 does not have any impact on our earnings per unit calculation.

The following sets forth the computation of basic and diluted earnings per limited partner unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents at 2005, 2004 and 2003.

	Year ended December 31,		
	2005	2004	2003
	(in millions, except per unit data)		
Numerator for basic and diluted earnings per limited partner unit:			
Net income	$217.8	$130.0	$59.4
Less:			
General partner's incentive distribution paid	(14.9)	(8.3)	(4.8)
Subtotal	202.9	121.7	54.6
General partner 2% ownership	(4.1)	(2.4)	(1.1)
Net income available to limited partners	198.8	119.3	53.5
Increase in general partner's incentive distribution-contingent equity issuance	—	—	(0.1)
Pro forma additional general partner's incentive distribution	(7.2)	—	—
Net income available to limited partners under EITF 03-06	$191.6	$119.3	$53.4
Denominator:			
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	69.3	63.3	52.7
Effect of dilutive securities:			
Weighted average LTIP units (see Note 9)	1.2	—	—
Contingent equity issuance	—	—	0.7
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	70.5	63.3	53.4
Basic net income per limited partner unit	$ 2.7	$ 1.8	$1.01
Diluted net income per limited partner unit	$ 2.7	$ 1.8	$1.00

Note 3—Acquisitions and Dispositions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price was allocated in accordance with such method.

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 $332.3 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 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 attributed to Link's gathering and marketing operations (in millions):

Cash paid for acquisition[1]	$ 268.
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.
Purchase price allocation	
Property and equipment	$ 260.
Inventory	3.4
Linefill	55.4
Inventory in third party assets	8.1
Goodwill	5.0
Other long-term assets	0.2
Total	$ 332.

(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 included (i) approximately $9.4 million in transaction costs, (ii) approximately $7.4 million related to a plan to 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 were substantially complete and the majority of the related costs were incurred as of December 31, 2004, resulting in total cash paid during 2004 of approximately $294 million.

The acquisition was initially funded with cash on hand, borrowings under our then 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.

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 $158.5 million in cash (including a deposit of approximately $16 million 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 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

Other Acquisitions

2005 Acquisitions

During 2005, we completed six small transactions for aggregate consideration of approximately $40.3 million. The transactions included crude oil trucking operations and several crude oil pipeline systems along the Gulf Coast as well as in Canada. We also acquired an LPG pipeline and terminal in Oklahoma. In addition, in September 2005, PAA/Vulcan acquired Energy Center Investments LLC ("ECI"), an indirect subsidiary of Sempra Energy, for approximately $250 million. We own 50% of PAA/Vulcan and a subsidiary of Vulcan Capital owns the other 50%. See Note 8 "Related Party Transactions."

2004 Acquisitions

During 2004, in addition to the Link and Capline acquisitions, we completed several other acquisitions for aggregate consideration totaling $73.1 million including transaction costs and approximately $14.4 million of LPG operating inventory acquired. 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. In addition, we accrued approximately $24.3 million of deferred purchase price related to a 2001 acquisition, which was ultimately settled with cash and units during 2004. See Note 6. The aggregate consideration for the 2003 acquisitions includes cash paid, 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 millions):

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

Dispositions

During 2005, 2004 and 2003, we sold various property and equipment for proceeds totaling approximately $9.4 million, $3.0 million and $8.5 million, respectively. Losses of approximately $3.2 million were recognized in 2005 and gains of approximately $0.6 million and $0.6 million were recognized in 2004 and 2003, respectively. These gains and losses are included as a component of depreciation and amortization in the consolidated statements of operations.

Note 4—Debt

Debt consists of the following:

	December 31, 2005	December 31, 2004
	(in millions)	
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 4.8% and 3.0% at December 31, 2005 and 2004, respectively	$ 219	$ 8
Working capital borrowings, bearing interest at a rate of 5.0% and 3.7% at December 31, 2005 and 2004, respectively(1)	155.4	88.2
Other	3.7	6.9
Total short-term debt	378.4	175.5
Long-term debt:		
4.75% senior notes due August 2009, net of unamortized discount of $0.6 million and $0.7 million at December 31, 2005 and 2004, respectively	174.4	174.3
7.75% senior notes due October 2012, net of unamortized discount of $0.2 million and $0.3 million at December 31, 2005 and 2004, respectively	199.8	199.7
5.63% senior notes due December 2013, net of unamortized discount of $0.5 million and $0.6 million at December 31, 2005 and 2004, respectively	249.5	249.4
5.25% senior notes due June 2015, net of unamortized discount of $0.7 million at December 31, 2005	149.3	—
5.88% senior notes due August 2016, net of unamortized discount of $1.0 million and $1.1 million at December 31, 2005 and 2004, respectively	174.0	173.9
Senior notes, net of unamortized discount(2)	947.0	797.3
Long-term debt under credit facilities and other—		
Senior unsecured revolving credit facility, bearing interest at 3.5% at December 31, 2004(1)	—	143.6
Other	4.7	8.1
Long-term debt under credit facilities and other	4.7	151.7
Total long-term debt(1)(2)	951.7	949.0
Total debt	$1,330.1	$1,124.5

(1) At December 31, 2005 and December 31, 2004, we have classified $155.4 million and $88.2 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (“NYMEX”) margin deposits.

(2) At December 31, 2005, the aggregate fair value of our fixed-rate senior notes is estimated to be approximately $976.0 million. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflect market.

Credit Facilities

In November 2005, we amended our senior unsecured credit facility to increase the aggregate capacity to $1 billion and the sub-facility for Canadian borrowings to $400 million. The amended facility can be expanded to $1.5 billion, subject to additional lender commitments, and has a final maturity of November 2010. The amended credit facility extends the maturity date and provides an additional $100 million of capacity over our previous facility. At December 31, 2005 and 2004, borrowings of approximately $155.4 million and $231.8 million, respectively, were outstanding under this facility.

Additionally, in the second quarter of 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $800 million. During 2005, we extended the maturity of the senior secured hedged inventory facility by one year to November 2006. 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.

Senior Notes

During May 2005, we completed the issuance of $150 million of 5.25% senior notes due 2015. The notes were issued at 99.5% of face value. Interest payments are due on June 15 and December 15 of each year. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

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 99.6% of face value and the 5.88% notes were sold at 99.3% 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 2013. The notes were issued at 99.7% of face value. Interest payments are due on June 15 and December 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 not significant.

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; and
- 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 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 periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2005 and 2004, we had outstanding letters of credit of approximately $55.5 million and $98.0 million, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2005 was approximately 7.6 years and the aggregate maturities for the next five years are as follows (in millions):

Calendar Year	Payment
2006	$
2007	2.4
2008	1.9
2009	175.3
2010	0.1
Thereafter	775.0
Total(1)	$954.7

(1) Excludes aggregate unamortized discount of $3.0 million on our various senior notes.

Note 5—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2005 consists of 73,768,576 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving effect to the general partner interest), and a 2% general partner interest. The number of common units outstanding includes the 3,245,700 Class C common units and the 1,307,190 Class B common units that converted in February 2005.

Conversion of 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.

Conversion of Subordinated Units

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 had a debit balance in Partners' capital of approximately $39.9 million at December 31, 2003. The debit balance was 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 exceeded net income allocated to unitholders.

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"). Per unit cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2005		2004		2003	
	Distribution[(1)]	Excess over MQD	Distribution[(1)]	Excess over MQD	Distribution[(1)]	Excess over MQD
First Quarter	$0.6125	$0.1625	$0.5625	$0.1125	$0.5375	$0.0875
Second Quarter . . .	$0.6375	$0.1875	$0.5625	$0.1125	$0.5500	$0.1000
Third Quarter	$0.6500	$0.2000	$0.5775	$0.1275	$0.5500	$0.1000
Fourth Quarter . . .	$0.6750	$0.2250	$0.6000	$0.1500	$0.5500	$0.1000

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

Distributions

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

	Distributions Paid					
	Common	Subordinated	GP			Distribution
Year	Units	Units[(1)]	Incentive	2%	Total	per LP unit
2005.	$178.4	$ -	$15.0	$3.6	$197.0	$2.58
2004.	$142.9	$ 4.	$ 8.	$3.0	$158.4	$2.30
2003.	$ 92.	$21.9	$ 4.	$2.3	$121.8	$2.19

(1) The subordinated units converted to common units in 2003 and 2004.

On January 24, 2006, we declared a cash distribution of $0.6875 per unit on our outstanding common units. The distribution was paid on February 14, 2006 to unitholders of record on February 3, 2006, for the period October 1, 2005 through December 31, 2005. The total distribution paid was approximately $57.3 million, with approximately $50.7 million paid to our common unitholders and $1.0 million and $5.6 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Equity Offerings

During the three years ended December 31, 2005, we completed the following equity offerings of our common units. Certain of these offerings involve related parties. See Note 8 "Related Party Transactions."

Period	Units	Gross Unit Price	Proceeds from Sale	GP Contribution	Costs	Net Proceeds
		(in millions, except unit and per unit amounts)				
September/October 2005	5,854,000	$42.00	$246.0	$5.0	$(9.1)	$241.9
February 2005	575,000	$38.13	$ 21.	$0.5	$(0.1)	$ 22.
July/August 2004	4,968,000	$33.25	$165.2	$3.4	$(7.7)	$160.9
April 2004	3,245,700	$30.81	$100.0	$2.0	$(1.0)	$101.0
December 2003	2,840,800	$31.94	$ 90.	$1.8	$(4.1)	$ 88.
September 2003	3,250,000	$30.91	$100.5	$2.1	$(4.6)	$ 98.
March 2003	2,645,000	$24.80	$ 65.	$1.3	$(3.0)	$ 63.

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 6—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, International Petroleum Exchange ("IPE") and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules to ensure that our hedging activities address our market risks. We formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in cash flows of hedged items.

Summary of Financial Impact

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

The majority of the instruments that qualify for hedge accounting are cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to Accumulated Other Comprehensive Income ("OCI") and recognized in revenues or crude oil and LPG purchases and related costs in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective, as defined in SFAS 133, in offsetting changes in cash flows of the hedged items are marked-to-market in revenues each period.

During 2005, our earnings include a net gain of approximately $18.4 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes:

a) a net mark-to-market loss on open positions of $18.9 million, which is comprised of:

- the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting (a loss of approximately $18.1 million) and

- the net change in fair value during the period of the portion of cash flow hedges related to open derivatives that is not highly effective in offsetting changes in cash flows of hedged items (a loss of approximately $0.8 million).

b) a net gain of $37.3 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to cash flow hedges that were recognized in earnings in conjunction with the underlying physical transactions that occurred during 2005.

During 2004, our earnings include a net gain of approximately $35.1 million resulting from all derivative activities, including the change in fair value of open derivatives and settled derivatives taken to earnings during the period. This gain includes:

a) a net mark-to-market gain on open positions of $1.0 million, which is comprised of:

- the net change in fair value during the period of open derivatives used to hedge price exposure that do not qualify for hedge accounting (a gain of approximately $0.9 million) and

- the net change in fair value during the period of the portion of cash flow hedges related to open derivatives that is not highly effective in offsetting changes in cash flows of hedged items (a gain of approximately $0.1 million).

b) a net gain of $34.1 million related to settled derivatives taken to earnings during the period. The majority of this net gain is related to our commodity price risk hedging activities that are offset by physical transactions, as discussed below.

The following table summarizes the net assets and liabilities related to the fair value of our open derivative positions on our consolidated balance sheet as of December 31, 2005 and 2004, respectively (in millions):

	December 31,	
	2005	2004
Other current assets	$ 45.7	$ 55.2
Other long-term assets	5.5	8.7
Other current liabilities	(72.5)	(18.9)
Other long-term liabilities and deferred credits	(6.5)	(10.6)
Net assets (liabilities)	$(27.8)	$ 34.4

The net liability as of December 31, 2005 is comprised of $16.6 million of unrealized losses recognized in earnings and $11.2 million of unrealized losses on effective cash flow hedges that are deferred to OCI. The majority of the $16.6 million of unrealized losses that have been recognized in earnings relate to activities associated with our storage assets. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month-to-month. We enter into derivative contracts that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. These derivatives do not qualify for hedge accounting because the contracts will not necessarily result in physical delivery. A portion of the net liability as of December 31, 2005, was caused by a reduction in backwardation (a decrease in the amount that the price of future deliveries are lower than current deliveries) from the time that we entered into the derivative contracts to the end of the year. The net gain or loss related to these instruments will offset storage revenue in the period that the derivative instruments are hedging.

At December 31, 2005 there was a total unrealized net loss of approximately $16.6 million deferred to OCI. This included $11.2 million (referenced above), which predominantly related to unrealized losses on derivatives used to hedge physical inventory in storage that receive hedge accounting, and $5.4 million relating to terminated interest rate swaps, which are being amortized to interest expense over the original terms of the terminated instruments. The inventory hedges are mostly short derivative positions that will result in losses when prices rise. These hedge losses are offset by an increase in the physical inventory value and will be reclassed into earnings from OCI in the same period that the underlying physical inventory is sold. The total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest.

Of the total net loss deferred in OCI at December 31, 2005, a net loss of $12.9 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 2008 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2005 and 2004, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring.

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, IPE 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 133, 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, 2005, we had no open interest rate hedging instruments. However, there is approximately $5.4 million deferred in OCI that relates to cash flow hedge instruments that were terminated and cash settled

($0.8 million related to an instrument settled in 2005, $1.3 million related to an instrument settled in 2004 and $3.3 million related to instruments settled in 2003) that relate to debt agreements refinanced in 2005, 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 $2.0 million over the next two years and the remaining $3.4 million over approximately ten years). Approximately $1.6 million and $1.5 million related to the terminated instruments were reclassified into interest expense during 2005 and 2004, respectively. 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, 2005, we had forward exchange contracts that allow us to exchange $2.0 million Canadian dollars for $1.5 million U.S. dollars, quarterly during 2006 (based on a Canadian dollar to U.S. dollar exchange rate of 1.32 to 1).

In addition, at December 31, 2005, we also had cross currency swap contracts for an aggregate notional principal amount of $19.0 million, effectively converting this amount of our U.S. dollar denominated debt to $29.4 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 has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2005, none of our long-term debt was denominated in Canadian dollars. 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,			
	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$ (16.0)	$ (16.0)	$ 42.	$ 42.
Options and swaps	$ (7)	$ (7)	$ (2)	$ (2)
Forward exchange contracts	$ (0)	$ (0)	$ (1)	$ (1)
Cross currency swaps	$ (6)	$ (6)	$ (6)	$ (6)
Short and long-term debt under credit facilities	$155.4	$155.4	$231.8	$231.8
Borrowings under senior secured hedged inventory facility	$219.3	$219.3	$ 80.	$ 80.
Senior notes	$947.0	$976.0	$797.3	$848.0

As of December 31, 2005 and 2004, 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 rates on our senior notes are 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 currently include cross currency swaps and forward exchange contracts 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 7—Major Customers and Concentration of Credit Risk

Marathon Petroleum Company LLC, and its predecessor Marathon Ashland Petroleum ("MAP"), accounted for 11%, 10% and 12% of our revenues for each of the three years in the period ended December 31, 2005. BP Oil Supply also accounted for 14% and 10% of our revenues for the years ended December 31, 2005 and 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 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 creditworthy, unless the credit risk can otherwise be reduced.

Note 8—Related Party Transactions

Our General Partner

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, 2005, 2004 and 2003 were approximately $165.2 million, $151.0 million and $88.1 million, respectively.

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, 2005, 2004 and 2003, the defined contribution plan matching expense was approximately $4.5 million, $4.0 million and $2.6 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, 2005, 2004 and 2003, these plans had expense of approximately $1.4 million, $1.0 million and $0.7 million, respectively. All of these amounts are included above in the total costs reimbursed by us to our general partner.

Long-Term Incentive Plans

Our general partner maintains the 1998 LTIP and the 2005 LTIP for employees and directors of our general partner. The plans generally consist of two components, a restricted or phantom unit plan and a unit option plan, and cover delivery of an aggregate of 4,425,000 common units. The plans are administered by the compensation committee of our general partner's board of directors. See Note 9 "Long-Term Incentive Plans."

Performance Option Plan

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 448,000 units have been granted. As of December 31, 2005, approximately 169,000 options remain outstanding under the plan, all of which are fully vested. The original exercise price of the options was $22 per unit, declining over time by an amount equal to 80% of each quarterly distribution per unit. As of December 31, 2005, the exercise price was approximately $13.85 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 have no obligation to reimburse the general partner for the cost of the units upon exercise of the options. In November and December of 2005, we sold approximately 170,000 units in a "10b5-1 Plan." The proceeds of the sales were allocated among the payment of tax liabilities and cash payments to optionees and to owners of the general partner.

Vulcan Energy Corporation

As of December 31, 2005, Vulcan Energy Corporation ("Vulcan Energy") and its affiliates owned approximately 54% of our general partner interest, as well as approximately 16.8% of our outstanding limited partner units.

Voting Agreement

In August 2005, one of the owners of our general partner notified the remaining owners of its intent to sell its 19% interest in the general partner. The remaining owners elected to exercise their right of first refusal, such that the 19% interest was purchased pro rata by all remaining owners. As a result of the transaction, the interest of Vulcan Energy increased from 44% to approximately 54%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove our independent directors, and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy's ownership interest. These ownership changes to our general partner had no impact on us.

Administrative Services Agreement

On October 14, 2005, Plains All American GP LLC ("GP LLC") and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the "Services Agreement"). Pursuant to the Services Agreement, GP LLC will provide administrative services to Vulcan Energy for consideration of approximately $650,000 per year, plus certain expenses. The Services Agreement will be effective for a period of three years, at which time it will automatically renew for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement. Vulcan Gas Storage LLC (discussed below) operates separately from Vulcan Energy, and we do not provide any services to Vulcan Gas Storage LLC under the Services Agreement.

Crude Oil Purchases from Calumet Florida L.L.C.

Until August 12, 2005, Vulcan Energy owned 100% of Calumet Florida L.L.C. ("Calumet"). Calumet is now owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. We purchase crude oil from Calumet and paid approximately $38.1 million, $28.3 million and $25.7 million to Calumet in 2005, 2004 and 2003, respectively. The majority of the $6.8 million balance due to related parties at December 31, 2005 is related to purchases of crude oil from Calumet in December 2005.

Equity Offering

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

Other Transactions

Investment in PAA/Vulcan Gas Storage, LLC

PAA/Vulcan, a limited liability company, was formed in 2005. PAA/Vulcan is owned 50% by us and the other 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital, the investment arm of Paul G. Allen. The Board of Directors of PAA/Vulcan is comprised of an equal number of our representatives and representatives of Vulcan Gas Storage and is responsible for providing strategic direction and policy-making. We are responsible for the day-to-day operations. PAA/Vulcan is not a variable interest entity, and we do not have the ability to control the entity; therefore, we account for the investment under the equity method in accordance with APB 18. This investment is reflected in other long-term assets in our consolidated balance sheet.

In September 2005, PAA/Vulcan acquired ECI, an indirect subsidiary of Sempra Energy, for approximately $250 million. ECI develops and operates underground natural gas storage facilities. We and Vulcan Gas Storage LLC each made an initial cash investment of approximately $112.5 million, and Bluewater Natural Gas Holdings, LLC, a subsidiary of PAA/Vulcan ("Bluewater") entered into a $90 million credit facility contemporaneously with closing. We currently have no direct or contingent obligations under the Bluewater credit facility.

We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund (i) certain projects specified at the time PAA/Vulcan acquired ECI and (ii) unspecified future capital needs up to an aggregate of $20 million. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for 50% of the cost. For any other project (or a project in which Vulcan Gas Storage declines to exercise its right to participate), we have the right to make additional capital contributions to fund 100% of the project. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage's interest. If at any time our interest in PAA/Vulcan exceeds 70%, Vulcan Gas Storage would have the right, but not the obligation, to make capital contributions proportionate to its ownership interest at the time.

In conjunction with formation of PAA/Vulcan and the acquisition of ECI, PAA and Paul G. Allen provided performance and financial guarantees to the seller with respect to PAA/Vulcan's performance under the purchase agreement, as well as in support of continuing guarantees of the seller with respect to ECI's obligations under certain gas storage and other contracts. PAA and Paul G. Allen would be required to perform under these guarantees only if ECI was unable to perform. In addition, we provided a guarantee under one contract with an indefinite life for which neither Vulcan Capital nor Paul G. Allen provided a guarantee. In exchange for the disproportionate guarantee, PAA will receive preference distributions totaling $1.0 million over ten years from PAA/Vulcan (distributions that would otherwise have been paid to Vulcan Gas Storage LLC). We believe that the fair value of the obligation to stand ready to perform is minimal. In addition, we believe the probability that we would be required to perform under the guaranty is extremely remote; however, there is no dollar limitation on potential future payments that fall under this obligation.

PAA/Vulcan will reimburse us for the allocated costs of PAA's non-officer staff associated with the management and day-to-day operations of PAA/Vulcan and all out-of-pocket costs. In addition, in the first fiscal year that EBITDA (as defined in the PAA/Vulcan LLC agreement) of PAA/Vulcan exceeds $75.0 million, we will receive a distribution from PAA/Vulcan equal to $6.0 million per year for each year since formation of the joint venture, subject to a maximum of 5 years or $30 million. Thereafter, we will receive annually a distribution equal to the greater of $2 million per year or two percent of the EBITDA of PAA/Vulcan.

Equity Offerings

Concurrently with our public offering of equity in September 2005, we sold 679,000 common units pursuant to our existing shelf registration statement to investment funds affiliated with Kayne Anderson Capital Advisors, L.P. (“KACALP”) in a privately negotiated transaction for a purchase price of $40.512 per unit (equivalent to the public offering price less underwriting discounts and commissions). KAFU Holdings, L.P., which owns a portion of our general partner and has a representative on our board of directors, is managed by KACALP.

In April 2004, we sold 3,245,700 unregistered Class C common units to a group of investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital pursuant to Rule 4(2) under the Securities Act. 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.

Note 9—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the “1998 LTIP”) and the 2005 Long-Term Incentive Plan (the “2005 LTIP”) for employees and directors of our general partner and its affiliates who perform services for us. Our general partner’s board of directors has the right to alter or amend the 2005 LTIP and the 1998 LTIP or any part of the plans 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. Awards contemplated by the 2005 LTIP include phantom units, restricted units, unit appreciation rights and unit options, as determined by the compensation committee or the board of directors (each an “Award”). Up to 3 million units may be issued in satisfaction of Awards under the 2005 LTIP. Certain Awards may also include distribution equivalent rights (“DERs”) in the discretion of the compensation committee or the board of directors. 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. 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. 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. No unit option grants have been made under the 1998 LTIP to date. However, the compensation committee or the board of directors may, in the future, make grants under the plan to employees and directors containing such terms as the compensation committee or the board of directors shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

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). The compensation committee or the board of directors may, in the future, make additional grants under the plans to employees and directors containing such terms as the compensation committee or the board of directors shall determine. Approximately 97,000 of the phantom units outstanding under the 1998 LTIP vested in 2005. We paid cash in lieu of delivery of common units for approximately 25,000 of the phantom units and issued approximately 47,000 new common units (after netting for taxes) in connection with the vesting. As of December 31, 2005, there are approximately 48,275 phantom units outstanding under the 1998 LTIP, which have vesting terms over the next four years, if certain performance criteria are met. The majority of the awards outstanding under the 1998 LTIP have performance-based vesting terms and, therefore, we recognize expense when it is considered probable that the performance criteria will be met.

Four of our non-employee directors each have received an LTIP award of 5,000 units. These awards vest annually in 25% increments (1,250 units each). The awards have an automatic re-grant feature such that as they vest, an equivalent amount is granted. For the other two non-employee directors, any director compensation is assigned to the entity that designated them as directors. In those cases, no LTIP award was granted, but in lieu, an equivalent cash payment is made. In June 2005, 5,000 non-employee director units vested.

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 2005 LTIP and 1998 LTIP. In addition, the Partnership may issue up to approximately 499,000 new common units under the 1998 LTIP and 3 million new common units under the 2005 LTIP to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan. If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase. The compensation committee or the board of directors, in its discretion, may grant tandem DERs with respect to phantom units.

During 2005, our board of directors and compensation committee approved grants of approximately 2.2 million phantom units and 1.6 million DERs under the 2005 LTIP. Approximately 1.5 million of the phantom units vest over a six-year period (with performance accelerators), while the remaining awards vest over time only if certain performance criteria are met and are forfeited after seven years if the performance criteria are not met. No phantom units vest prior to the dates indicated below for each tranche. The DERs vest over time and terminate with the vesting or forfeiture of the related phantom units. The following awards were outstanding under the 2005 LTIP at December 31, 2005:

Summary of 2005 LTIP

As of December 31, 2005
(in thousands)

Annualized Distribution Rate	Date	Phantom Units A[(1)]	Phantom Units B[(2)]	Phantom Units Total	DERs A[(1)]	DERs B[(2)]	DERs Total
$2.60	May 2007	565	150	715	363	150	513
$2.70	May 2008	—	—	—	136	75	211
$2.80	May 2009	431	150	581	136	75	211
$2.90	May 2010	—	—	—	136	100	236
$3.00	May 2010	431	200	631	136	100	236
$2.90	May 2008	22	57	79	—	57	57
$3.00	May 2009	17	57	74	—	57	57
$3.10	May 2010	17	56	73	—	56	56
		1,483	670	2,153	907	670	1,577

(1) Awards that vest in May 2011 at the latest. Achievement of the indicated distribution rate performance criteria can accelerate the vesting to the date indicated. The phantom unit awards are common stock equivalents as they will vest at the end of a determinant time and thus are included in our diluted earnings per unit calculation.

(2) Awards that vest only upon the achievement of the distribution rate performance criteria and the date indicated. In addition, the awards will be forfeited if the performance criteria are not met in seven years. Until the performance criteria are met, these awards are not considered common stock equivalents in our diluted earnings per unit calculation.

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. Compensation expense is recognized ratably over time for the phantom units and DERs that vest based on the passage of time. To the extent that the vesting of the awards or DERs is accelerated or considered probable of acceleration, the related compensation expense will also be accelerated. For those phantom units and DERs that vest only upon the achievement of performance criteria, expense is recognized when it is considered probable the criteria will be achieved.

We have concluded that it is probable that we will achieve a $3.00 annualized distribution rate and therefore have accelerated the recognition of compensation expense related to the portion of the awards that vest up to that rate. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under the LTIP plans will vest. As a result, we recognized total compensation expense of approximately $26.1 million in 2005 and $7.9 million in 2004 related to the awards granted under our 1998 LTIP and our 2005 LTIP plans.

Note 10—Commitments and Contingencies

Commitments

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, 2005, are summarized below (in millions):

2006	$19.8
2007	$16.7
2008	$12.4
2009	$11.5
2010	$ 9.
Thereafter	$44.0

Expenditures related to leases for 2005, 2004 and 2003 were $25.7 million, $20.1 million and $13.4 million, respectively.

Contingencies

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. 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.

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency ("EPA"), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4.5 million to $5.0 million. In cooperation with the appropriate state and federal environmental authorities, we have substantially completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. We have been informed by EPA that it has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice for further investigation in connection with a possible civil penalty enforcement action under the Federal Clean Water Act.

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

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

At December 31, 2005, our reserve for environmental liabilities totaled approximately $22.4 million. At December 31, 2005, we have recorded receivables totaling approximately $14.2 million for amounts recoverable under insurance and from third parties under indemnification agreements. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

Hurricanes Katrina and Rita. During the third quarter of 2005 we experienced damage to various facilities and equipment resulting from hurricanes in the Gulf of Mexico. We have substantially completed preliminary assessments of damages and repair efforts are underway. We believe that the majority of the repair costs will be recovered through our insurance policies.

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

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

Note 11—Environmental Remediation

We currently own or lease properties where hazardous liquids, including hydrocarbons, are being or have been handled. These properties and the hazardous liquids or associated generated wastes disposed thereon may be subject to CERCLA, RCRA and analogous state and Canadian federal and provincial laws. Under such laws, 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 2005, 2004 and 2003 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 2005 and 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 agreed to bear $11 million of the first $20 million of pre-May 1999 environmental issues. We also agreed to 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 agreed to 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 $20.0 million in connection with the Link acquisition.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, SOP 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. SOP has made a claim against the policy; however, we do not believe that the claim substantially reduced 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. Other than with respect to liabilities associated with two Superfund sites at which it is alleged that Scurlock deposited waste oils, this indemnity has expired or was terminated by agreement.

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, 2005, our reserve for environmental liabilities totaled approximately $22.4 million (approximately $14.6 million of this reserve is related to liabilities assumed as part of the Link acquisition). Approximately $14.4 million of our environmental reserve is classified as current and $8 million is classified as long-term. At December 31, 2005, we have recorded receivables totaling approximately $14.2 million ($7.7 million related to estimated future remediation costs) 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 12—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total[1]
	(in millions, except per unit data)				
2005					
Revenues[2]	$6,638.5	$7,160.7	$8,664.4	$8,713.7	$31,177.3
Gross margin	69.4	102.2	111.4	95.8	378.8
Operating income	47.3	76.0	84.9	67.4	275.6
Net income	32.8	62.3	69.0	53.7	217.8
Basic net income per limited partner unit	0.43	0.76	0.81	0.65	2.77
Diluted net income per limited partner unit	0.43	0.74	0.79	0.64	2.72
Cash distributions per common unit[3]	$ 0.61	$ 0.63	$ 0.65	$ 0.67	$
2004					
Revenues[2]	$3,804.6	$5,131.7	$5,867.0	$6,172.1	$20,975.5
Gross margin	59.6	64.9	74.5	63.7	262.7
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 income per limited partner unit	0.44	0.54	0.59	0.32	1.89
Cash distributions per common unit[3]	$ 0.56	$ 0.56	$ 0.57	$ 0.60	$

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

(2) Includes buy/sell transactions. See Note 2.

(3) Represents cash distributions declared and paid in the applicable period.

Note 13—Operating Segments

Our operations consist of two operating segments: (i) pipeline transportation operations and (ii) gathering, marketing, terminalling and storage operations. 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 our terminalling and storage activities and gathering and marketing activities are counter-cyclical. We believe that this balance of activities, combined with our pipeline transportation operations, generally provides us with the flexibility to maintain a base level of margin irrespective of whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions. 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 resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities.

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

	Pipeline	GMT&S (in millions)	Total
Twelve Months Ended December 31, 2005[1]			
Revenues:			
External Customers (includes buy/sell revenues of $197.1, $16,077.8, and $16,274.9, respectively)[2]	$ 991	$30,185.7	$31,177.3
Intersegment[3]	138.7	0.9	139.6
Total revenues of reportable segments	$1,130.3	$30,186.6	$31,316.9
Segment profit[2][4][5]	$ 175	$ 18	$ 35
Capital expenditures	$ 127	$	$ 19
Total assets[6]	$1,480.4	$ 2,526.	$ 4,006.
SFAS 133 impact[2]	$	$ (1)	$ (1)
Maintenance capital	$	$	$
Twelve Months Ended December 31, 2004			
Revenues:			
External Customers (includes buy/sell revenues of $149.8, $11,247.0, and $11,396.8, respectively)[2]	$ 752	$20,222.6	$20,975.5
Intersegment[3]	122.0	0.9	122.9
Total revenues of reportable segments	$ 874	$20,223.5	$21,098.4
Segment profit[2][4][5]	$ 157	$	$ 24
Capital expenditures	$ 520	$ 13	$ 65
Total assets	$1,507.5	$ 1,652.	$ 3,160.
SFAS 133 impact[2]	$	$	$
Maintenance capital	$	$	$

	Pipeline	GMT&S	Total
		(in millions)	
Twelve Months Ended December 31, 2003			
Revenues:			
External Customers (includes buy/sell revenues of $166.2, $6,124.9, and $6,291.1, respectively)(2)	$ 605	$11,984.7	$12,589.8
Intersegment(3)	53.5	0.9	54.4
Total revenues of reportable segments	$ 658	$11,985.6	$12,644.2
Segment profit(2)(4)(5)	$ 8	$	$ 14
Capital expenditures	$ 211	$	$ 23
Total assets	$1,221.0	$ 87	$ 2,095.
SFAS 133 impact(2)	$	$	$
Maintenance capital	$	$	$

(1) During 2005, we reclassified certain minor pipeline gathering assets from the GMT&S segment to the Pipeline segment. Historically, we have been the sole shipper on these assets as part of our gathering and marketing operations. Prior period segment information has not been restated for this change since the impact to such periods was not material.

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

(3) Intersegment sales are conducted at arms length.

(4) GMT&S segment profit includes interest expense on contango inventory purchases of $23.7 million, $2.0 million and $1.0 million for the twelve months ended December 31, 2005, 2004 and 2003, respectively.

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

	Year ended December 31,		
	2005	2004	2003
Segment profit	$359.1	$248.7	$144.4
Depreciation and amortization	(83.5)	(68.7)	(46.2)
Equity earnings in PAA/Vulcan Gas Storage, LLC	1.0	—	—
Interest expense	(59.4)	(46.7)	(35.2)
Interest income and other (expense), net	0.6	(0.2)	(3.6)
Income before cumulative effect of change in accounting principle	$217.8	$133.1	$ 59.

(6) Total assets, as reported on the consolidated balance sheet, includes the $113.5 million investment in PAA/Vulcan Gas Storage, LLC, which is not included in either of our operating segments.

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,		
	2005	2004	2003
Revenues			
United States (includes buy/sell revenues of $14,749.0, $10,164.6, and $5,621.6, respectively)	$26,199.7	$17,499.5	$10,536.8
Canada (includes buy/sell revenues of $1,525.9, $1,232.2, and $669.5, respectively)	4,977.6	3,476.0	2,053.0
	$31,177.3	$20,975.5	$12,589.8

	December 31,	
	2005	2004
Long-Lived Assets		
United States	$1,887.0	$1,670.8
Canada	422.5	379.7
	$2,309.5	$2,050.5

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

March 2, 2006

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)

March 2, 2006

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)	March 2, 2006
/s/ HARRY N. PEFANIS **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	March 2, 2006
/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, 2006
/s/ TINA L. VAL **Tina L. Val**	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	March 2, 2006
/s/ EVERARDO GOYANES **Everardo Goyanes**	Director of Plains All American GP LLC	March 2, 2006
/s/ GARY R. PETERSEN **Gary R. Petersen**	Director of Plains All American GP LLC	March 2, 2006
/s/ ROBERT V. SINNOTT **Robert V. Sinnott**	Director of Plains All American GP LLC	March 2, 2006
/s/ DAVID N. CAPOBIANCO **David N. Capobianco**	Director of Plains All American GP LLC	March 2, 2006
/s/ ARTHUR L. SMITH **Arthur L. Smith**	Director of Plains All American GP LLC	March 2, 2006
/s/ J. TAFT SYMONDS **J. Taft Symonds**	Director of Plains All American GP LLC	March 2, 2006