PART IV

Item 15. ***Exhibits, Financial Statement Schedules and Reports on Form 8-K***

(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).

3.2 — Second Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.2 to Form 8-K filed August 27, 2001).

3.3 — Second Amended and Restated Agreement of Limited Partnership of All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.3 Form 8-K filed August 27, 2001).

3.4 — Certificate of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.4 to Registration Statement, file No. 333-64107).

3.5 — Certificate of Limited Partnership of Plains Marketing, L.P. dated as of November 10, 1998 (incorporated by reference to Exhibit 3.5 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

3.6 — Articles of Conversion of All American Pipeline Company dated as of November 10, 1998 (incorporated by reference to Exhibit 3.5 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

3.7 — Amended and Restated Limited Partnership Agreement of Plains AAP, L.P., dated as of June 8, 2001 (incorporated by reference to Exhibit 3.1 to Form 8-K filed June 11, 2001).

3.8 — Amended and Restated Limited Liability Company Agreement of Plains All American GP, LLC dated as of June 8, 2001, as amended by first Amendment dated September 16, 2003 (incorporated by reference to Exhibit 3.1 to Quarterly Form 10-Q for the period ended September 30, 2003).

4.1 — Registration Rights Agreement, dated as of June 8, 2001, among Plains All American Pipeline, L.P., Sable Holdings, L.P., E-Holdings III, L.P., KAFU Holdings, LP, PAA Management, L.P., Mark E. Strome, Strome Hedgecap Fund, L.P., John T. Raymond and Plains All American Inc. (incorporated by reference to Exhibit 4.1 to Form 8-K filed June 11, 2001).

4.2 — Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002).

4.3	—	First Supplemental Indenture dated as of September 25, 2002 (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q for the Quarter ended September 30, 2002).
*4.4	—	Second Supplemental Indenture dated as of December 10, 2003.
*4.5	—	Registration Rights Agreement dated December 10, 2003.
10.01	—	Contribution, Assignment and Amendment Agreement, dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 27, 2001).
10.02	—	Contribution, Assignment and Amendment Agreement, dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to Form 8-K filed June 11, 2001).
10.03	—	Separation Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to Form 8-K filed June 11, 2001).
10.04	—	Pension and Employee Benefits Assumption and Transition Agreement, dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to Form 8-K filed June 11, 2001).
**10.05	—	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 period ended June 30, 2003).
**10.06	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to Registration Statement on Form S-8, File No. 333-74920).
**10.07	—	Phantom MLP unit Agreement for Greg L. Armstrong (incorporated by reference to Exhibit 99.3 to Registration Statement on Form S-8, File No. 333-74920).
**10.08	—	Phantom MLP Unit Agreement for Phillip D. Kramer (incorporated by reference to Exhibit 99.5 to Registration Statement on Form S-8, File No. 333-74920).
**10.09	—	Phantom MLP Unit Agreement for Tim Moore (incorporated by reference to Exhibit 99.6 to Registration Statement on Form S-8, File No. 333-74920).
**10.10	—	Phantom MLP Unit Agreement for Harry N. Pefanis (incorporated by reference to Exhibit 99.7 to Registration Statement on Form S-8, File No. 333-74920).

**10.11 — Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.3 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001).

**10.12 — Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.4 to Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2001).

10.13 — Asset Purchase and Sale Agreement between Murphy Oil Company Ltd. And Plains Marketing Canada, L.P. (incorporated by reference to Form 8-K filed May 10, 2001).

10.14 — Crude Oil Marketing Agreement among Plains Resources Inc., Plains Illinois Inc., Stocker Resources, L.P., Calumet Florida, Inc. and Plains Marketing, L.P. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.07 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

10.15 — Omnibus Agreement among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., and Plains All American Inc. dated as of November 23, 1998 (incorporated by reference to Exhibit 10.08 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

10.16 — Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to Registration Statement, file No. 333-64107).

10.17 — Transportation Agreement dated August 2, 1993, between All American Pipeline Company and Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to Registration Statement, File No. 333-64107).

10.18 — First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

10.19 — Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to Annual Report on Form 10-K for the Year Ended December 31, 1998).

*10.20 — 364-Day Revolving Credit Agreement dated November 21, 2003 among Plains All American Pipeline, L.P and Fleet National Bank and certain other lenders.

*10.21 — Uncommitted Senior Secured Discretionary Contango Credit Agreement dated November 21, 2003 among Plains Marketing, L.P. and Fleet National Bank and certain other lenders.

*10.22
— US/Canada Revolving Credit Agreement dated November 21, 2003 among Plains All American Pipeline, L.P, PMC (Nova Scotia) Company, Plains Marketing Canada, L.P. and Fleet National Bank and certain other lenders.

*23.1
— Consent of Independent Auditors

*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 Chief Executive Officer pursuant to 18 U.S.C. § 1350.

*32.2
— Certification of Chief Financial Officer pursuant to 18 U.S.C. § 1350

*
Filed herewith

**
Management contract or compensatory plan or arrangement

(b) Reports on Form 8-K

A Current Report on Form 8-K was furnished on February 24, 2004, in connection with disclosure of first quarter estimates and earnings guidance.

A Current Report on Form 8-K was filed on January 15, 2004 with an unaudited balance sheet of Plains AAP, L.P., as of September 30, 2003, attached as an exhibit.

A Current Report on Form 8-K was filed on December 22, 2003 with an underwriting agreement for an equity offering attached as an exhibit.

A Current Report on Form 8-K was filed on December 17, 2003 in connection with our disclosure of entering into an agreement to purchase the interests of Shell Pipeline Company' L.P.'s interests in certain pipeline systems.

A Current Report on Form 8-K was filed and furnished on December 17, 2003 in connection with our disclosure of the status of our acquisition activities.

A Current Report on Form 8-K was furnished on December 9, 2003, in connection with disclosure of our presentation at the Wachovia Securities Pipeline Conference and Symposium.

A Current Report on Form 8-K was furnished on December 3, 2003, in connection with the private offering of $250 million of 5.625% senior notes.

A Current Report on Form 8-K/A was furnished on October 29, 2003 to correct certain inaccuracies in the Current Report furnished on October 28, 2003.

A Current Report on Form 8-K was furnished on October 28, 2003, in connection with disclosure of our third-quarter results and fourth-quarter forecasts.

A Current Report on Form 8-K was furnished on October 7, 2003, in connection with our disclosure of our presentation at the IPAA's 2003 Oil & Gas Investment Symposium West.

A Current Report on Form 8-K was furnished on September 24, 2003, in connection with our disclosure of our presentation at the Herold's 12th Annual Pacesetters Energy Conference.

A Current Report on Form 8-K was furnished on September 16, 2003, in connection with our disclosure of our presentation at the RBC Capital Markets North American Energy and Power Conference.

A Current Report on Form 8-K was filed on September 10, 2003 with an underwriting agreement for an equity offering attached as an exhibit.

A Current Report on Form 8-K was furnished on September 8, 2003, in connection with the announcement of an equity offering.

SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

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

By: PLAINS ALL AMERICAN GP LLC,
its general partner

Date: February 27, 2004

By: /s/ GREG L. ARMSTRONG

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

Date: February 27, 2004

By: /s/ PHILLIP D. KRAMER

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

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

Name	Title	Date
/s/ GREG L. ARMSTRONG **Greg L. Armstrong**	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	Date: February 27, 2004
/s/ HARRY N. PEFANIS **Harry N. Pefanis**	President and Chief Operating Officer of Plains All American GP LLC	Date: February 27, 2004
/s/ PHILLIP D. KRAMER **Phillip D. Kramer**	Executive Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	Date: February 27, 2004
/s/ TINA L. VAL **Tina L. Val**	Vice President—Accounting (Principal Accounting Officer)	Date: February 27, 2004
/s/ EVERARDO GOYANES **Everardo Goyanes**	Director of Plains All American GP LLC	Date: February 27, 2004
/s/ GARY R. PETERSEN **Gary R. Petersen**	Director of Plains All American GP LLC	Date: February 27, 2004
/s/ JOHN T. RAYMOND **John T. Raymond**	Director of Plains All American GP LLC	Date: February 27, 2004

/s/ ROBERT V. SINNOTT		
Robert V. Sinnott	Director of Plains All American GP LLC	Date: February 27, 2004
/s/ ARTHUR L. SMITH		
Arthur L. Smith	Director of Plains All American GP LLC	Date: February 27, 2004
/s/ J. TAFT SYMONDS		
J. Taft Symonds	Director of Plains All American GP LLC	Date: February 27, 2004

PLAINS ALL AMERICAN PIPELINE, L.P.

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

Report of Independent Auditors

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income and of changes in accumulated other comprehensive income (loss) present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company'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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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 2 to the consolidated financial statements, the Partnership changed its method of accounting for derivative instruments and hedging activities effective January 1, 2001.

PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2004

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands, except unit data)

	December 31, 2003	December 31, 2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 4,137	$ 3,501
Accounts receivable, net	590,645	499,909
Inventory	105,967	81,849
Other current assets	32,225	17,676
Total current assets	732,974	602,935
PROPERTY AND EQUIPMENT	1,272,634	1,030,303
Accumulated depreciation	(121,595)	(77,550)
	1,151,039	952,753
OTHER ASSETS		
Pipeline linefill	122,653	62,558
Other, net	88,965	48,329
Total assets	$ 2,095,631	$ 1,666,575
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 603,460	$ 488,922
Due to related parties	26,981	23,301
Short-term debt (see Note 6)	127,259	99,249

Other current liabilities	44,219	25,777
Total current liabilities	801,919	637,249
LONG-TERM LIABILITIES		
Long-term debt under credit facilities, including current maturities of $9,000 for the 2002 period	70,000	310,126
Senior notes, net of unamortized discount of $1,009 and $390, respectively	448,991	199,610
Other long-term liabilities and deferred credits	27,994	7,980
Total liabilities	1,348,904	1,154,965
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS' CAPITAL		
Common unitholders (49,502,556 and 38,240,939 units outstanding at December 31, 2003, and December 31, 2002, respectively)	744,073	524,428
Class B common unitholder (1,307,190 units outstanding at each date)	18,046	18,463
Subordinated unitholders (7,522,214 and 10,029,619 units outstanding at December 31, 2003, and December 31, 2002, respectively)	(39,913)	(47,103)
General partner	24,521	15,822
Total partners' capital	746,727	511,610
	$ 2,095,631	$ 1,666,575

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

	Year Ended December 31,		
	2003	**2002**	**2001**
REVENUES			
Crude oil and LPG sales	$ 11,952,623	$ 7,892,162	$ 6,481,305
Pipeline margin activities	505,287	382,513	285,618
Pipeline tariffs and fees	99,887	79,939	54,234
Other	32,052	29,609	47,058
Total revenues	12,589,849	8,384,223	6,868,215
COSTS AND EXPENSES			
Crude oil and LPG purchases and related costs	11,727,355	7,726,323	6,338,365
Pipeline margin activities purchases	486,154	362,311	270,786
Other purchases	19,027	14,862	4,965
Operating expenses (excluding LTIP charge)	134,177	106,436	106,854
LTIP charge—operations	5,727	—	—
Inventory valuation adjustment	—	—	4,984
General and administrative (excluding LTIP charge)	49,969	45,663	46,586
LTIP charge—general and administrative	23,063	—	—
Depreciation and amortization	46,821	34,068	24,307
Total costs and expenses	12,492,293	8,289,663	6,796,847
Gains on sales of assets	648	—	984
OPERATING INCOME	98,204	94,560	72,352
OTHER INCOME/(EXPENSE)			
Interest expense (net of capitalized interest of $524, $773 and $153)	(35,226)	(29,057)	(29,082)
Interest income and other, net (Note 2)	(3,530)	(211)	401

Income before cumulative effect of accounting change		59,448		65,292		43,671
Cumulative effect of accounting change		—		—		508
NET INCOME	$	59,448	$	65,292	$	44,179
NET INCOME-LIMITED PARTNERS	$	53,473	$	60,912	$	42,239
NET INCOME-GENERAL PARTNER	$	5,975	$	4,380	$	1,940
BASIC NET INCOME PER LIMITED PARTNER UNIT						
Income before cumulative effect of accounting change	$	1.01	$	1.34	$	1.12
Cumulative effect of accounting change		—		—		0.01
Net income	$	1.01	$	1.34	$	1.13
DILUTED NET INCOME PER LIMITED PARTNER UNIT						
Income before cumulative effect of accounting change	$	1.00	$	1.34	$	1.12
Cumulative effect of accounting change		—		—		0.01
Net Income	$	1.00	$	1.34	$	1.13
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		52,743		45,546		37,528
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		53,400		45,546		37,528

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Year Ended December 31,		
	2003	**2002**	**2001**
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 59,448	$ 65,292	$ 44,179
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	46,821	34,068	24,307
Gains on sales of assets	(648)	—	(984)
Cumulative effect of accounting change	—	—	(508)
Noncash compensation expense	—	—	5,741
Allowance for doubtful accounts	360	146	3,000
Inventory valuation adjustment	—	—	4,984
Change in derivative fair value	(363)	(243)	(207)
Net cash paid for termination of interest rate hedging instruments	(6,152)	—	—
Loss on refinancing of debt	3,272	—	—
Noncash portion of LTIP charge (Note 11)	28,052	—	—
Changes in assets and liabilities, net of acquisitions:			
Accounts receivable and other	(102,005)	(136,480)	(18,856)
Inventory	(38,941)	105,944	(117,878)
Pipeline linefill	(46,790)	(11,060)	(13,736)
Accounts payable and other current liabilities	117,412	106,065	46,671
Other long-term liabilities and deferred credits	4,600	1,200	600
Due to related parties	3,452	8,962	(7,266)
Net cash provided by (used in) operating activities	68,518	173,894	(29,953)
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(168,359)	(324,628)	(229,162)
Additions to property and equipment	(65,416)	(40,590)	(21,069)
Proceeds from sales of assets	8,450	1,437	740
Net cash used in investing activities	(225,325)	(363,781)	(249,491)

CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facilities	(6,197)	(4,770)	99,583
Net borrowings/(repayments) on long-term revolving credit facilities	87,773	(42,144)	34,677
Principal payments on senior secured term loans (Note 6)	(297,000)	(3,000)	—
Cash paid in connection with financing arrangements	(5,191)	(5,435)	(6,351)
Net proceeds from the issuance of common units (Note 7)	250,341	145,046	227,549
Proceeds from the issuance of senior unsecured notes (Note 6)	249,340	199,600	—
Distributions paid to unitholders and general partner (Note 7)	(121,822)	(99,841)	(75,929)
Net cash provided by financing activities	157,244	189,456	279,529
Effect of translation adjustment on cash	199	421	—
Net increase (decrease) in cash and cash equivalents	636	(10)	85
Cash and cash equivalents, beginning of period	3,501	3,511	3,426
Cash and cash equivalents, end of period	$ 4,137	$ 3,501	$ 3,511
Cash paid for interest, net of amounts capitalized	$ 36,382	$ 28,550	$ 33,341

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CHANGES IN PARTNERS' CAPITAL

(in thousands)

	Common Unitholders		Class B Common Unitholders		Subordinated Unitholders		General Partner	Total Partners' Capital
	Units	Amount	Units	Amount	Units	Amount	Amount	Amount
Balance at December 31, 2000	23,049	$ 217,073	1,307	$ 21,042	10,030	$ (27,316)	$ 3,200	$ 213,999
Issuance of units	8,867	222,032	—	—	—	—	5,517	227,549
Noncash compensation expense	—	—	—	—	—	—	5,741	5,741
Net income	—	29,436	—	1,476	—	11,327	1,940	44,179
Distributions	—	(51,271)	—	(2,549)	—	(19,558)	(2,551)	(75,929)
Other comprehensive loss	—	(8,708)	—	(435)	—	(3,344)	(255)	(12,742)
Balance at December 31, 2001	31,916	408,562	1,307	19,534	10,030	(38,891)	13,592	402,797
Issuance of units	6,325	142,013	—	—	—	—	3,033	145,046
Net income	—	45,857	—	1,736	—	13,319	4,380	65,292
Distributions	—	(70,821)	—	(2,762)	—	(21,188)	(5,070)	(99,841)
Other comprehensive loss	—	(1,183)	—	(45)	—	(343)	(113)	(1,684)
Balance at December 31, 2002	38,241	524,428	1,307	18,463	10,030	(47,103)	15,822	511,610
Issuance of units	8,736	245,093	—	—	—	—	5,237	250,330
Issuance of units under LTIP	18	555	—	—	—	—	11	566
Net income	—	41,278	—	1,370	—	10,825	5,975	59,448
Conversion of 25% of subordinated units	2,507	(9,823)	—	—	(2,507)	9,823	—	—
Distributions	—	(89,801)	—	(2,860)	—	(21,939)	(7,222)	(121,822)
Other comprehensive income	—	32,343	—	1,073	—	8,481	4,698	46,595
Balance at December 31, 2003	49,502	$ 744,073	1,307	$ 18,046	7,523	$ (39,913)	$ 24,521	$ 746,727

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2003	**2002**	**2001**
		(in thousands)	
Net income	$ 59,448	$ 65,292	$ 44,179
Other comprehensive income (loss)	46,595	(1,684)	(12,742)
Comprehensive income	$ 106,043	$ 63,608	$ 31,437

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

	Net Deferred Loss on Derivative Instruments	**Currency Translation Adjustments**	**Total**
		(in thousands)	
Balance at December 31, 2000	$ —	$ —	$ —
Cumulative effect of accounting change	(8,337)	—	(8,337)
Reclassification adjustments for settled contracts	(2,526)	—	(2,526)
Changes in fair value of outstanding hedge positions	6,123	—	6,123
Currency translation adjustment	—	(8,002)	(8,002)
Balance at December 31, 2001	(4,740)	(8,002)	(12,742)
Reclassification adjustments for settled contracts	797	—	797
Changes in fair value of outstanding hedge positions	(4,264)	—	(4,264)
Currency translation adjustment	—	1,783	1,783

2002 Activity	(3,467)	1,783	(1,684)
Balance at December 31, 2002	(8,207)	(6,219)	(14,426)
Reclassification adjustments for settled contracts	(28,151)	—	(28,151)
Changes in fair value of outstanding hedge positions	28,666	—	28,666
Currency translation adjustment	—	46,080	46,080
2003 Activity	515	46,080	46,595
Balance at December 31, 2003	$ (7,692)	$ 39,861	$ 32,169

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. is a publicly traded Delaware limited partnership (the "Partnership") engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. We refer to liquified petroleum gas and other petroleum products collectively as "LPG". We were formed in September 1998 to acquire and operate the midstream crude oil business and assets of Plains Resources Inc. and its wholly-owned subsidiaries ("Plains Resources") as a separate, publicly traded master limited partnership. We completed our initial public offering in November 1998. As a result of subsequent equity offerings and the purchase in 2001 by senior management and a group of financial investors of majority control of our general partner and a portion of Plains Resources' limited partner units (the "General Partner Transition"), Plains Resources' overall effective ownership in us was reduced to approximately 22%.

As a result of the 2001 transaction, our 2% general partner interest is held by Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Plains All American GP LLC manages our operations and activities and employs our officers and personnel, who devote 100% of their efforts to the management of the Partnership. Unless the context otherwise requires, we use the term "general partner" to refer to both Plains AAP, L.P. and Plains All American GP LLC. Plains AAP, L.P. and Plains All American GP LLC are essentially held by 7 owners with the largest interest, 44%, held by Plains Resources. We use the phrase "former general partner" to refer to the subsidiary of Plains Resources that formerly held the general partner interest.

Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P., and are concentrated in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2003 and 2002, and the consolidated results of our operations, cash flows, changes in partners' capital and comprehensive income (loss) for the years ended December 31, 2003, 2002 and 2001, and changes in accumulated other comprehensive income for the years ended December 31, 2003 and 2002. All significant intercompany transactions have been eliminated. Certain reclassifications were made to prior periods to conform with the current period presentation.

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) estimated useful lives of assets, which impacts depreciation and amortization, (ii) allowance for doubtful accounts receivable, (iii) accruals related to purchases and sales including mark-to-market estimates pursuant to Statement of Financial Accounting Standards ("SFAS") No. 133 "Accounting For Derivative Instruments and Hedging Activities", as amended, (iv) other liability and contingency accruals, (v) accruals related to our Long-Term Incentive Plan (the "LTIP") and (vi) estimated fair value of assets and liabilities acquired and identification of associated intangible assets as well as
transaction related costs. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Gathering and marketing revenues are accrued at the time title to the product sold transfers to the purchaser, which occurs upon receipt of the product by the purchaser. Terminalling and storage revenues are recognized at the time service is performed. Revenues for the transportation of crude oil are recognized either at the point of delivery or at the point of receipt pursuant to regulated and non-regulated tariffs.

Purchases and Related Costs

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

Operating Expenses and General and Administrative Expenses

Operating expenses consist of various field and pipeline operating expenses including fuel and power costs, telecommunications, labor costs for truck drivers and pipeline field personnel, maintenance costs, regulatory compliance, 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.

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 at times may exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that any possible credit risk is minimal.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil. There were no amounts due from related parties at December 31, 2003 or 2002. The majority of our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities, in many cases involving complex exchanges of crude oil volumes. We make a determination of the amount, if any, of the line of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided in the form of standby letters of credit.

Accounts receivable included in the consolidated balance sheets are reflected net of our allowance for doubtful accounts. We routinely review our receivable balances to identify past due amounts and analyze the reasons such amounts have not been collected. In many instances, such delays involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy.

At December 31, 2003 and 2002, approximately 99% of net accounts receivable classified as current were less than 60 days past scheduled invoice date, and our allowance for doubtful accounts receivable classified as current totaled $0.2 million and $3.1 million, respectively. We consider these reserves adequate. At December 31, 2003 we had no accounts receivable balances or allowance for doubtful accounts classified as long-term. At December 31, 2002, approximately $11.5 million of accounts receivable ($6.5 million, net of a $5.0 million allowance) was classified as long-term. Following is a reconciliation of the changes in our allowance for doubtful accounts balances (in millions):

	December 31,		
	2003	**2002**	**2001**
Balance at beginning of year	$ 8.1	$ 8.0	$ 5.0
Applied to accounts receivable balances	(8.3)	—	—
Charged to expense	0.4	0.1	3.0
Balance at end of year	$ 0.2	$ 8.1	$ 8.0

Inventory

Inventory primarily consists of crude oil and LPG in pipelines, storage tanks and rail cars which is valued at the lower of cost or market, with cost determined using an average cost method. In the fourth quarter of 2001, the Partnership recorded a $5.0 million noncash writedown of operating crude oil inventory to reflect prices at December 31, 2001. During 2001, the price of crude oil traded on the NYMEX averaged $25.98 per barrel. At December 31, 2001, the NYMEX crude oil price was approximately 24% lower, or $19.84 per barrel. There was no writedown of operating crude oil inventory at December 31, 2003 or 2002, as the market prices of crude oil and LPG were higher than our average cost per barrel. At December 31, 2003 and 2002, inventory consisted of (in millions):

	December 31,	
	2003	**2002**
Crude oil	$ 50.6	$ 53.5
LPG	53.8	28.3
Other	1.6	—
	$ 106.0	$ 81.8

Property and Equipment and Pipeline Linefill

Property and equipment, net is stated at cost and consisted of the following (in millions):

	December 31,	
	2003	2002
Crude oil pipelines and facilities	$ 1,114.5	$ 909.3
Crude oil and LPG storage and terminal facilities	100.8	82.4
Trucking equipment and other	43.8	30.0
Office property and equipment	13.5	8.6
	1,272.6	1,030.3
Less accumulated depreciation	(121.6)	(77.5)
	$ 1,151.0	$ 952.8

Depreciation expense for each of the three years in the period ended December 31, 2003, was $42.4 million, $30.2 million and $21.6 million, respectively. Our policy is to depreciate property and equipment using the straight-line method over estimated useful lives as follows:

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

In accordance with our capitalization policy, costs associated with acquisitions and improvements, including related interest costs, which expand our existing capacity are capitalized. For the years ended December 31, 2003, 2002 and 2001, capitalized interest was $0.5 million, $0.8 million and $0.2 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.

Linefill and minimum working inventory requirements are recorded at lower of cost or market and consists of crude oil and LPG used to pack a pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location as well as minimum crude oil necessary to operate our storage and terminalling facilities. At December 31, 2003, we had approximately 4.6 million barrels of crude oil and 7.7 million gallons of LPG used to maintain our minimum linefill and working inventory requirements. Proceeds from the sale and repurchase of pipeline linefill are reflected as cash flows from operating activities in the accompanying consolidated statements of cash flows.

Asset Retirement Obligation

In June 2001, the FASB issued SFAS No. 143 "Asset Retirement Obligations." SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. Effective January 1, 2003, we adopted SFAS 143, as required. Determination of the amounts to be recognized upon adoption is based upon numerous estimates and assumptions, including future retirement costs, future inflation rates and the credit-adjusted risk-free interest rate. The majority 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 fair value of the asset retirement obligations cannot be reasonably estimated, as the settlement dates are indeterminate. We will record such asset retirement obligations in the period in which we can reasonably determine the settlement dates. The adoption of this statement did not have a material impact on our financial position, results of operations or cash flows.

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, and there have been no events or circumstances indicating that the carrying value of any of our assets may not be recoverable.

Other Assets

Other assets, net consist of the following (in millions):

	December 31,	
	2003	2002
Goodwill	$ 39.4	$ 12.9
Deposit on Capline Acquisition	15.8	—
Debt issue costs	12.1	21.6
Investment in affiliate	7.8	8.0
Long term receivable, net	—	6.5
Fair value of derivative instruments	5.9	2.6
Intangible assets (contracts)	2.6	2.4
Other	7.1	2.6
	90.7	56.6
Less accumulated amortization	(1.7)	(8.3)
	$ 89.0	$ 48.3

Goodwill is recorded as the amount of the purchase price in excess of the fair value of certain assets purchased. At December 31, 2003, we recorded additional consideration related to the deferred portion of the purchase price in the CANPET acquisition (See Note 3). The entire amount of this consideration was recorded as additional goodwill. In accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," which we adopted January 1, 2002, 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, 2003, no impairment has occurred.

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. During the fourth quarter of 2003, we replaced our senior secured credit facilities with new senior unsecured credit facilities and we completed the sale of $250 million of 5.625% senior notes (See Note 6). We capitalized approximately $5.1 million of costs associated with those transactions. Also, in conjunction with the credit facility refinancing, we incurred a non-cash charge of approximately $3.3 million attributable to a loss on the early extinguishment of debt (included in Interest income and other, net on the Consolidated Statement of Operations). The loss consists of unamortized debt issue costs written off as a result of the completion of the new credit facility. In addition, we wrote off approximately $11.3 million of fully amortized debt issue costs and the related accumulated amortization.

Amortization of other assets for each of the three years in the period ended December 31, 2003, was $4.4 million, $3.9 million and $2.7 million, respectively.

Environmental Matters

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 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.

Income and Other Taxes

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

The Partnership's Canadian operations are conducted through an operating limited partnership, of which our wholly owned subsidiary PMC (Nova Scotia) Company is the general partner. For Canadian tax purposes, the general partner is taxed as a corporation, subject to income taxes and a capital-based tax at federal and provincial levels. For 2003 and 2002, the income tax was not material and the capital-based tax was approximately $0.4 million (U.S.) and $0.5 million (U.S), respectively. In addition, interest payments made by Plains Marketing Canada, L.P. on its intercompany loan from Plains Marketing, L.P. are subject to a 10% Canadian withholding tax, which for 2003 and 2002 totaled $0.4 million and $0.5 million, respectively, and is recorded in other expense.

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.

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. Beginning January 1, 2001, we record all derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133, "Accounting for Derivative Instruments and Hedging Activities" as amended by SFAS 137 and SFAS 138 (collectively "SFAS 133"). At adoption, and in accordance with the transition provisions of

SFAS 133, we recorded a loss of $8.3 million in Other Comprehensive Income ("OCI"), representing the cumulative effect of an accounting change to recognize, at fair value, all cash flow derivatives. We also recorded a noncash gain of $0.5 million in earnings as a cumulative effect adjustment. 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 OCI and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period for (i) derivatives characterized as fair value hedges, (ii) derivatives that do not qualify for hedge accounting and (iii) the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of hedged items.

Net Income Per Unit

Basic and diluted net income per unit is determined by dividing net income after deducting the amount allocated to the general partner interest, (including its incentive distribution in excess of its 2% interest), by the weighted average number of outstanding limited partner units, including common units and subordinated units. Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership. Other comprehensive income is allocated based on the same effective percentages. The following table sets forth the computation of basic and diluted net income per limited partner unit for 2003, 2002 and 2001 (in millions, except per unit amounts). The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for the impact of the contingent equity issuance related to the CANPET acquisition for the calculation of diluted net income per limited partner unit (See Note 3).

	Year Ended December 31,		
	2003	**2002**	**2001**
	(in millions, except per unit data)		
Net income	$ 59.4	$ 65.3	$ 44.2
Less:			
General partner incentive distributions	(4.9)	(3.1)	(1.1)
General partner 2% ownership	(1.1)	(1.3)	(0.9)
Numerator for basic earnings per limited partner unit:			
Net income available for common unitholders	53.4	60.9	42.2
Effect of dilutive securities:			
Increase in general partner's incentive distribution—Contingent equity issuance	(0.1)	—	—
Numerator for diluted earnings per limited partner unit	$ 53.3	$ 60.9	$ 42.2
Denominator:			
Denominator for basic earnings per limited partner unit—weighted average number of limited partner units	52.7	45.5	37.5
Effect of dilutive securities:			
Contingent equity issuance	0.7	—	—

Denominator for diluted earnings per limited partner unit —weighted average number of limited partner units	53.4	45.5	37.5
Basic net income per limited partner unit	$ 1.01	$ 1.34	$ 1.13
Diluted net income per limited partner unit	$ 1.00	$ 1.34	$ 1.13

Note 3—Acquisitions

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

Significant Acquisitions

Shell West Texas Assets

On August 1, 2002, we acquired from Shell Pipeline Company LP and Equilon Enterprises LLC interests in approximately 2,000 miles of gathering and mainline crude oil pipelines and approximately 8.9 million barrels (net to our interest) of above-ground crude oil terminalling and storage assets in West Texas (the "Shell acquisition"). The results of operations and assets from this acquisition have been included in our consolidated financial statements and in our pipeline operations segment since that date. The primary assets included in the transaction were interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. These assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we are a provider of storage and terminalling services. The total purchase price of $324.4 million consisted of (i) $304.0 million in cash, which was borrowed under our revolving credit facility, (ii) approximately $9.1 million related to the settlement of pre-existing accounts receivable and inventory balances and (iii) approximately $11.3 million of estimated transaction and closing costs. The entire purchase price was allocated to property and equipment.

CANPET Energy Group Inc.

In July 2001, we acquired the assets of CANPET Energy Group Inc. ("CANPET"), a Calgary-based Canadian crude oil and LPG marketing company, for approximately $24.6 million plus excess inventory at the closing date of approximately $25.0 million. A portion of the purchase price, payable in common units or cash at our option, was deferred subject to various performance standards being met. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units assuming (i) the deferred portion of the purchase price was paid in common units and (ii) they had been outstanding since the acquisition date. As of December 31, 2003, we determined that it was beyond a reasonable doubt that the performance standards were met and we recorded additional consideration of $24.3 million (see Note 7) resulting in aggregate consideration of $73.9 million. The deferred consideration was recorded as additional goodwill.

At the time of the acquisition, CANPET's activities consisted of gathering approximately 75,000 barrels per day of crude oil and marketing an average of approximately 26,000 barrels per day of natural gas liquids or LPG's. The principal assets acquired include a crude oil handling facility, a 130,000-barrel tank facility, LPG facilities, existing business relationships and operating inventory. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States. Initial financing for the acquisition was provided through borrowings under our credit facility.

The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Inventory	$	28.1
Goodwill		35.4
Intangible assets (contracts)		1.0
Pipeline linefill		4.3
Crude oil gathering, terminalling and other assets		5.1
Total	$	73.9

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we closed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $158.4 million in cash after post-closing adjustments (the "Murphy acquisition"), including financing and transaction costs. Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate transmission mainlines (including dual lines on which condensate is shipped for blending purposes and blended crude is shipped in the opposite direction) and associated gathering and lateral lines, approximately 1.1 million barrels of crude oil storage and terminalling capacity located primarily in Kerrobert, Saskatchewan, approximately 254,000 barrels of pipeline linefill and tank inventories, and 121 trailers used primarily for crude oil transportation. The acquired assets are part of our strategy to establish a Canadian operation that complements our operations in the United States.

Murphy agreed to continue to transport production from fields previously delivering crude oil to these pipeline systems, under a long-term contract. At the time of the acquisition, the volume under the contract was approximately 11,000 barrels per day. Total volumes transported on the pipeline system in 2001 were approximately 223,000 barrels per day of light, medium and heavy crudes, as well as condensate.

The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Crude oil pipeline, gathering and terminal assets	$	148.0
Pipeline linefill		7.6
Net working capital items		2.0
Other property and equipment		0.5
Other assets, including debt issue costs		0.3
Total	$	158.4

Other Acquisitions

2003 Acquisitions

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

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

2002 Acquisitions

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

2001 Acquisition

In December 2001, in addition to the CANPET and Murphy acquisitions, we acquired the Wapella Pipeline System from private investors for approximately $12.0 million, including transaction costs. The entire purchase price was allocated to property and equipment. The system includes a crude oil pipeline and approximately 21,500 barrels of crude oil storage capacity located along the system as well as a truck terminal.

Note 4—Asset Dispositions

Shutdown of Rancho Pipeline System

We acquired the Rancho Pipeline System in conjunction with the Shell acquisition. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminated in March 2003. Upon termination, the agreement required the owners to take the pipeline system, in which we owned an approximate 50% interest, out of service. Accordingly, we notified our shippers and did not accept nominations for movements after February 28, 2003. This shutdown was contemplated at the time of the acquisition and was accounted for under purchase accounting in accordance with SFAS No. 141 "Business Combinations." The pipeline was shut down on March 1, 2003 and a purge of the crude oil linefill was completed in April 2003. In June 2003, we completed transactions whereby we transferred all of our ownership interest in approximately 240 miles of the total 458 miles of the pipeline in exchange for $4.0 million and approximately 500,000 barrels of crude oil tankage in West Texas. The remaining portion will either be sold or salvaged. No gain or loss has been recorded on the shutdown of the Rancho System or these transactions.

Other Dispositions

During 2003 and 2002, we sold various other property and equipment for proceeds totaling approximately $8.5 million and $1.4 million, respectively. A gain of approximately $0.6 million was recognized in 2003 and no gain or loss was recognized in 2002. In December 2001, we sold excess communications equipment and recognized a gain of $1.0 million.

Note 5—Industry Credit Markets

Throughout the latter part of 2001 and all of 2002, there have been significant disruptions and extreme volatility in the financial markets and credit markets. Because of the credit intensive nature of the energy industry and extreme financial distress at several large, diversified energy companies, the energy industry has been especially impacted by these developments. Accordingly, we are exposed to an increased level of direct and indirect counterparty credit and performance risk.

The majority of our credit extensions and therefore our accounts receivable relate to our gathering and marketing activities that can generally be described as high volume and low margin activities. In our credit approval process, we must determine 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, 2003, we had received approximately $44.0 million of advance cash payments and prepayments from third parties to mitigate credit risk.

Note 6—Debt

Short-term debt consists of the following (in millions):

	December 31,			
	2003		2002	
Senior secured hedged inventory borrowing facility bearing interest at a rate of 1.9% at December 31, 2003	$	100.5	$	—
Senior unsecured $425 million domestic revolving credit facility—working capital borrowings, bearing interest at a rate of 4.0% at December 31, 2003[1]		25.3		—
Senior secured letter of credit and borrowing facility bearing interest at a rate of 3.4% at December 31, 2002		—		97.7
Other		1.5		1.5
Total short-term debt and current maturities of long-term debt	$	127.3	$	99.2

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

Long-term debt consists of the following (in millions):

	December 31,			
	2003		2002	
5.63% senior notes due December 2013, net of unamortized discount of $0.7 million	$	249.3	$	—
7.75% senior notes due October 2012, net of unamortized discount of $0.3 million and $0.4 million at December 31, 2003 and 2002, respectively		199.7		199.6
Senior unsecured $170 million Canadian revolving credit facility, bearing interest at a rate of 2.17% at December 31, 2003		70.0		—
Senior secured domestic revolving credit facility, bearing interest at a rate of 4.8% at December 31, 2002		—		10.4
Senior secured term B loan, bearing interest at a rate of 3.9% at December 31, 2002		—		198.0
Senior secured term loan, bearing interest at a rate of 3.9% at December 31, 2002		—		99.0

$30 million Canadian senior secured revolving credit facility, bearing interest at a rate of 5.0% at December 31, 2002	—	2.7
Total long-term debt[(1),(2)]	$ 519.0	$ 509.7

(1) At December 31, 2002, we classified $9 million of term loan payments due in 2003 as long term due to our intent and ability to refinance those maturities using the revolving facility.

(2) At December 31, 2003, we have classified $25.3 million of borrowings under our Senior unsecured domestic revolving credit facility as short-term. These borrowings are designated as working capital borrowings under this facility and primarily are for hedged LPG inventory and NYMEX margin deposits and must be repaid within one year.

Credit Facilities

During November 2003, we refinanced our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purpose of financing hedged crude oil. The $750 million of new facilities consist of:

- a four-year, $425 million U.S. revolving credit facility;
- a 364-day, $170 million Canadian revolving credit facility with a five-year term-out option;
- a four-year, $30 million Canadian working capital revolving credit facility; and
- a 364-day, $125 million revolving credit facility.

All of the facilities with the exception of the $200 million hedged inventory facility are unsecured. The $200 million hedged inventory facility is an uncommitted working capital facility, which will be used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility will be secured by the inventory purchased under the facility and the associated accounts receivable, and will be repaid from the proceeds from the sale of such inventory.

Senior Notes

During December 2003, we completed the sale of $250 million of 5.625% senior notes due in December 2013. The notes were issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) at a discount of $0.7 million, resulting in an effective interest rate of 5.66%. Interest payments are due on June 15 and December 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) at a discount of $0.4 million, resulting in an effective interest rate of 7.78%. Interest payments are due on April 15 and October 15 of each year. The notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for subsidiaries which are minor.

Covenants and Compliance

Our credit facilities, the indenture governing the 5.625% senior notes and the indenture governing the 7.75% senior notes contain cross default provisions. Our credit facilities prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

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

Our credit facilities treat a change of control as an event of default and also require us to maintain:

- a debt coverage ratio which will not be greater than: 4.50 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); and
- an interest coverage ratio that is not less than 2.75 to 1.0.

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 facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, they do not restrict our ability to make distributions of "available cash" as defined in our partnership agreement. We are in compliance with the covenants contained in our credit facilities 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. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for up to seventy-day periods and are terminated upon completion of each transaction. At December 31, 2003 and 2002, we had outstanding letters of credit of approximately $57.9 million and $52.5 million, respectively. In addition to changes in the level of activity and other factors, the amount of letters of credit outstanding varies based on NYMEX crude oil prices, which were $32.52 per barrel and $29.45 per barrel at December 31, 2003 and 2002, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2003, was approximately 9 years and all balances mature in 2009 or later.

Note 7—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2003 consists of (1) 50,809,746 common units, including 1,307,190 Class B common units, representing a 85.4% effective aggregate ownership interest in the Partnership and its subsidiaries, (after giving affect to the general partner interest), (2) 7,522,214 subordinated units representing a 12.6% effective aggregate ownership interest in the Partnership and its subsidiaries (after giving affect to the general partner interest) and (3) a 2% general partner interest.

Class B Common Units

The Class B common units are initially pari passu with common units with respect to distributions, and are convertible into common units upon approval of a majority of the common unitholders. The Class B unitholders may request that we call a meeting of common unitholders to consider approval of the conversion of Class B units into common units. If the approval of a conversion by the common unitholders is not obtained within 120 days of a request, each Class B common unitholder will be entitled to receive distributions, on a per unit basis, equal to 110% of the amount of distributions paid on a common unit, with such distribution right increasing to 115% if such approval is not secured within 90 days after the end of the 120-day period. Except for the vote to approve the conversion, Class B common units have the same voting rights as the 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.

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 ("MQD"), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions"). Cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2003		2002		2001	
	Distribution	Excess over MQD	Distribution	Excess over MQD	Distribution	Excess over MQD
First Quarter	$ 0.5500	$ 0.1000	$ 0.5250	$ 0.0750	$ 0.4750	$ 0.0250
Second Quarter	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875	$ 0.5000	$ 0.0500
Third Quarter	$ 0.5500	$ 0.1000	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625
Fourth Quarter	$ 0.5625	$ 0.1125	$ 0.5375	$ 0.0875	$ 0.5125	$ 0.0625

Distributions

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

During 2003, we paid distributions of approximately $121.8 million ($2.19 on a per unit basis), with approximately $92.7 million paid to our common unitholders, $21.9 million paid to our subordinated unitholders and $2.3 million and $4.9 million paid to our general partner for its general partner and incentive distribution interests, respectively.

During 2002, we paid distributions of approximately $99.8 million ($2.11 on a per unit basis), with approximately $73.6 million paid to our common unitholders, $21.1 million paid to our subordinated unitholders and $2.0 million and $3.1 million paid to our general partner for its general partner and incentive distribution interests, respectively.

During 2001, we paid distributions of approximately $75.9 million ($1.95 on a per unit basis), with approximately $53.8 million paid to our common unitholders, $19.5 million paid to our subordinated unitholders and $1.5 million and $1.1 million paid to our general partner for its general partner and incentive distribution interests, respectively.

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

Equity Offerings

In December 2003, we completed a public offering of 2,840,800 common units for $31.94 per unit. The offering resulted in gross proceeds of approximately $90.7 million from the sale of the units and approximately $1.8 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $4.1 million. Net proceeds of approximately $88.4 million were used to reduce outstanding borrowings under our revolving credit facility.

In September 2003, we completed a public offering of 3,250,000 common units for $30.91 per unit. The offering resulted in gross proceeds of approximately $100.5 million from the sale of the units and approximately $2.1 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $4.5 million. Net proceeds of approximately $98.0 million were used to reduce outstanding borrowings under the domestic revolving credit facility and reduce the principal balance on our Senior secured term B loan.

In March 2003, we completed a public offering of 2,645,000 common units for $24.80 per unit. The offering resulted in gross proceeds of approximately $65.6 million from the sale of the units and approximately $1.3 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $3.0 million. Net proceeds of approximately $63.9 million were used to reduce outstanding borrowings under the domestic revolving credit facility.

In August 2002, we completed a public offering of 6,325,000 common units for $23.50 per unit. The offering resulted in cash proceeds of approximately $148.6 million from the sale of the units and approximately $3.0 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $6.6 million. Net proceeds of approximately $145.0 million were used to reduce outstanding borrowings under the domestic revolving credit facility.

In May 2001, we completed a public offering of 3,966,700 common units. Total net cash proceeds from the offering, including our former general partner's proportionate contribution, were approximately $100.7 million. In addition, in October 2001, we completed a public offering of 4,900,000 common units. Net cash proceeds from the offering, including our general partner's proportionate contribution, were approximately $126.0 million. The net proceeds were used to repay borrowings under our revolving credit facility, a portion of which was used to finance our Canadian acquisitions.

Contingent Equity Issuance

In connection with the CANPET acquisition in July 2001, a portion of the purchase price, payable in common units, was deferred subject to various performance objectives being met. These objectives have been met as of December 31, 2003, and the deferred amount is payable on April 30, 2004. The number of common units issued in satisfaction of the deferred payment will depend upon the average trading price of our common units for a ten-day trading period prior to the payment date and the Canadian and U.S. dollar exchange rate on the payment date. In addition, an amount will be paid equivalent to the distributions that would have been paid on the common units had they been outstanding since the acquisition was consummated. At our option, the deferred payment may be paid in cash rather than the issuance of units. Assuming the entire obligation is satisfied with common units, based on the foreign exchange rate in effect at December 31, 2003, (1.30 to 1 Canadian dollar to U.S. dollar exchange rate) and an estimated $33.35 per unit price, approximately 613,000 units would be issued and approximately $3.9 million would be paid related to distributions. We currently anticipate that one-third of the contingent purchase price and all of the amount related to past distributions will be paid in cash and the remainder will be settled with approximately 409,000 common units.

Note 8—Derivatives and Financial Instruments

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

Summary of Financial Impact

The following is a summary of the financial impact of the derivative instruments and hedging activities discussed below. At December 31, 2003, the balance sheet includes assets of $27.9 million ($22.0 million current), liabilities of $28.1 million

($17.1 million current) and related unrealized losses deferred to OCI of $1.6 million related to open derivative positions. Revenues for the year ended December 31, 2003 include a noncash gain of $0.4 million ($1.4 million noncash gain net of the reversal of the prior period fair value adjustment related to contracts that settled during the current year). Our hedge-related assets and liabilities are included in other current and non-current assets and liabilities in the consolidated balance sheet. In addition, during the fourth quarter of 2003 we terminated and cash settled three interest-rate risk hedging instruments for approximately $6.2 million. The net deferred loss related to these instruments was deferred in OCI and is being amortized into interest expense over the original terms of the terminated instruments (approximately fifty percent over three years and the remaining fifty percent over ten years).

As of December 31, 2003, the total amount of deferred net losses recorded in OCI are expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. During the periods ended December 31, 2003 and 2002, no amounts were reclassified to earnings from OCI in connection with forecasted transactions that were no longer considered probable of occurring. Based on the aggregate amounts deferred in OCI at December 31, 2003, a net loss of $0.4 million will be reclassified to earnings in the next twelve months and the remainder by 2013. Since a portion of these amounts are based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

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

Commodity Price Risk Hedging

We hedge our exposure to price fluctuations with respect to crude oil and LPG in storage, and expected purchases, sales and transportation of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies (see Note 5 for a discussion of the mitigation of credit risk). In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair values. The majority of our commodity price risk derivative instruments qualify for hedge accounting as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedge are deferred in OCI and recognized in revenues or purchases in the periods during which the underlying physical transactions occur. At December 31, 2003 there was an unrealized gain of $2.1 million deferred in OCI related to our commodity price risk activities. All of these deferred positions mature by December 2004. An unrealized gain of $1.2 million related to these activities was deferred in OCI at December 31, 2002. For each of the three years ended December 31, 2003, income of $0.5 million, $0.3 million and $0.4 million (excluding the impact of the adoption of SFAS 133), respectively, was included in revenues due to changes in the fair value of derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective. We have determined that our physical purchase and sale agreements qualify for the normal purchase and sale exclusion and thus are not subject to SFAS 133.

Controlled Trading Program

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG 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 and an aggregate of 250,000 barrels of LPG. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues. There were no open positions under this program at December 31, 2003 and 2002. The realized earnings impact related to these activities for the years ended December 31, 2003, 2002 and 2001, was a loss of $0.1 million, income of $0.1 million and a loss of $0.9 million, respectively.

Interest Rate Risk Hedging

We also utilize various products, such as interest rate swaps, collars and treasury locks to hedge interest obligations on specific debt issuances, including anticipated debt issuances. All of these instruments are placed with large creditworthy financial institutions.

At December 31, 2003, there was one interest rate swap outstanding with an aggregate notional principal amount of $50 million. The interest rate swap is based on LIBOR rates and provides for a LIBOR rate of 4.3% expiring in March 2004. Interest on the underlying debt being hedged is based on LIBOR plus a margin.

The instruments outstanding at December 31, 2002, consisted of interest rate swaps and a treasury lock with an aggregate notional principal amount of $150 million. The interest rate swaps were based on LIBOR rates and provided for a LIBOR rate of 5.1% for a $50.0 million notional principal amount expiring October 2006 and a LIBOR rate of 4.3% for a $50.0 million notional principal amount expiring March 2004. Interest on the underlying debt that was hedged was based on LIBOR plus a margin. During 2002, we entered into a treasury lock in anticipation of the issuance of our 7.75% senior notes due October 2012 and potential subsequent add-on thereto. A treasury lock is a financial derivative instrument that enables the company to lock in the U.S. Treasury Note rate. The treasury lock had a notional principal amount of $50.0 million and an effective interest rate of 4.60%. The treasury lock matured in January 2003, was extended to March 2003 with an effective interest rate of 4.68%, was converted to a forward starting swap and was subsequently unwound in conjunction with the issuance of our 5.625% Senior Notes.

The instruments outstanding at December 31, 2003 and 2002 qualify for hedge accounting as cash flow hedges in accordance with SFAS 133. The effective portion of changes in fair values of these hedges is recorded in OCI until the related hedged item impacts earnings. At December 31, 2003, and 2002, there was a $6.5 million unrealized loss and a $9.6 million unrealized loss, respectively, deferred in OCI related to our interest rate risk activities. As discussed above, approximately $6.1 million of the loss deferred in OCI at December 31, 2003, relates to instruments terminated and cash settled during 2003. During 2003 and 2002, there were no amounts recognized in earnings related to hedge ineffectiveness.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in Canadian dollars (CAD), we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at times, a portion of our debt is denominated in Canadian dollars. At December 31, 2003 we did not have any Canadian dollar debt and at December 31, 2002, $2.7 million of our long-term debt was denominated in Canadian dollars ($4.3 million CAD based on a Canadian dollar to U.S. dollar exchange rate of 1.58 to 1). All of these financial instruments are placed with large creditworthy financial institutions.

At December 31, 2003, we had forward exchange contracts that allow us to exchange approximately $2.0 million Canadian for at least $1.5 million U.S. quarterly during 2004 and approximately $1.0 million Canadian for at least $0.7 million U.S. quarterly during 2005 (based on a Canadian dollar to U.S. dollar exchange rate of approximately 1.33 to 1 and 1.34 to 1, respectively). In addition, at December 31, 2003, we also had cross currency swap contracts for an aggregate notional principal amount of $23.0 million, effectively converting this amount of our U.S. dollar denominated debt to $35.6 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. on May 2004 and May 2005 and has a final maturity in May 2006 ($19.0 million U.S.).

At December 31, 2002, we had forward exchange contracts and forward extra option contracts that allow us to exchange $3.0 million Canadian for at least $1.9 million U.S. quarterly during 2003 (based on a Canadian dollar to U.S. dollar exchange rate of 1.54 to 1). At December 31, 2002, we also had cross currency swap contracts for an aggregate notional principal amount of $24.8 million, effectively converting this amount of our U.S. dollar denominated debt to $38.3 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1).

The forward exchange contracts and forward extra option contracts qualify for hedge accounting as cash flow hedges and the cross currency swaps qualify for hedge accounting as fair value hedges, both in accordance with SFAS 133. Such derivative activity resulted in an unrealized loss of $0.3 million and an unrealized gain of $0.2 million deferred in OCI related to our currency exchange rate cash flow hedges at December 31, 2003 and 2002, respectively. The earnings impact related to our currency exchange rate fair value hedges was a loss of $0.1 million for the year ended December 31, 2003 and nominal for the year ended December 31, 2002.

Fair Value of Financial Instruments

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

	December 31,			
	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
NYMEX futures	$ 7.5	$ 7.5	$ 0.6	$ 0.6
Options and swaps	$ (3.3)	$ (3.3)	$ (0.6)	$ (0.6)
Forward exchange contracts	$ (0.4)	$ (0.4)	$ 0.1	$ 0.1
Forward extra option contracts	$ —	$ —	$ 0.2	$ 0.2
Cross currency swaps	$ (4.8)	$ (4.8)	$ 0.3	$ 0.3
Treasury lock	$ —	$ —	$ (3.3)	$ (3.3)
Interest rate swaps	$ (0.4)	$ (0.4)	$ (6.3)	$ (6.3)
Short and long-term debt under credit facilities	$ 95.3	$ 95.3	$ 409.4	$ 409.4
Senior notes	$ 449.0	$ 482.9	$ 199.6	$ 209.0

As of December 31, 2003 and 2002, 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 approximate fair value primarily because the interest rates fluctuate with prevailing market rates, while the interest rate on the 5.625% and the 7.75% senior notes is fixed and the fair value is based on quoted market prices.

The carrying amount of our derivative financial instruments approximate fair value as these instruments are recorded on the balance sheet at their fair value under SFAS 133. Our derivative financial instruments include cross currency swaps, forward exchange and extra option contracts, interest rate swap collar and treasury lock agreements for which fair values are based on current liquidation values. We also have over-the-counter option and swap contracts for which fair values are estimated based on quoted prices from 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 9—Major Customers and Concentration of Credit Risk

Marathon Ashland Petroleum accounted for 12%, 10% and 11% of our revenues for each of the three years in the period ended December 31, 2003. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of the revenues from Marathon Ashland Petroleum pertain to our gathering, marketing, terminalling and storage operations. We believe that the loss of this customer would have only a short-term impact on our operating results. There can be no assurance, however, that we would be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered credit worthy, unless the credit risk can otherwise be reduced (see Note 5).

Note 10—Related Party Transactions

Reimbursement of Expenses of Our General Partner and Its Affiliates

We do not directly employ any persons to manage or operate our business. These functions are provided by employees of our general partner (or, in the case of our Canadian operations, PMC (Nova Scotia) Company). Our general partner does not receive a management fee or other compensation in connection with its management of us. We reimburse our general partner for all direct and indirect costs of services provided, including the costs of employee, officer and director compensation and benefits allocable to us, and all other expenses necessary or appropriate to the conduct of our business, and allocable to us. Our agreement provides that our general partner will determine the expenses allocable to us in any reasonable manner determined by our general partner in its sole discretion. Historically, an allocation was made for overhead associated with officers and employees who divided time between us and Plains Resources. As a result of the General Partner Transition, all of the employees and officers of the general partner devote 100% of their efforts to our business and there are no allocated expenses. Total costs reimbursed by us to our general partner in for the years ended December 31, 2003, 2002 and 2001 were approximately $88.1 million, $70.8 million and $31.3 million, respectively. Total costs reimbursed by us to our former general partner and Plains Resources were approximately $31.2 million for the year ended December 31, 2001.

Crude Oil Marketing Agreement

We are the exclusive marketer/purchaser for all of Plains Resources' and its subsidiaries' equity crude oil production. The marketing agreement with Plains Resources provides that we will purchase for resale at market prices the majority of Plains Resources' crude oil production for which we charge a fee of $0.20 per barrel. This fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2003, 2002 and 2001, we paid Plains Resources approximately $25.7 million, $247.7 million and $223.2 million, respectively, for the purchase of crude oil under the agreement, including the royalty share of production, and recognized margins of approximately $0.2 million, $1.8 million and $1.8 million from the marketing fee for the same periods, respectively. In our opinion, these purchases were made at prevailing market prices. In November 2001, the marketing agreement automatically extended for an additional three-year period. In connection with the separation of Plains Resources and one of its subsidiaries, discussed below, Plains Resources divested the bulk of its producing properties. As a result, we do not anticipate the marketing arrangement with Plains Resources to be material to our operating results in the future. We are in the process of negotiating an amended agreement to reflect the separation. As currently in effect, the marketing agreement will terminate upon a "change in control" of Plains Resources or our general partner. The recently announced buyout of Plains Resources stock would constitute a change of control; however, we received assurances prior to the initial announcement that neither Plains Resources nor the buyout group intend for the agreement to terminate.

In December 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production Company ("PXP") to its shareholders. PXP is a successor participant to the Plains Resources Marketing agreement. For the year ended December 31, 2003, we paid PXP approximately $277.9 million for the purchase of crude oil under the agreement, including the royalty share of production and recognized margins of approximately $1.7 million from the marketing fee. In our opinion, these purchases were made at prevailing market prices. We are also party to a Letter Agreement with Stocker Resources, L.P. (now PXP) that provides that if the Marketing Agreement terminates before our crude oil sales agreement with Tosco Refining Co. ("Tosco") terminates, PXP will continue to sell and we will continue to purchase PXP's equity crude oil production from the Arroyo Grande field (now owned by a subsidiary of PXP) under the same terms as the Marketing Agreement until our Tosco sales agreement terminates. We are in the process of negotiating the terms of an amended agreement with PXP.

Separation Agreement

A separation agreement was entered into in connection with the General Partner Transition pursuant to which (i) Plains Resources has indemnified us for (a) claims relating to securities laws or regulations in connection with the upstream or midstream businesses, based on alleged acts or omissions occurring on or prior to June 8, 2001 or (b) claims related to the upstream business, whenever arising, and (ii) we have indemnified Plains Resources for claims related to the midstream business, whenever arising. Plains Resources also has agreed to indemnify and maintain liability insurance for the individuals who were, on or before June 8, 2001, directors or officers of Plains Resources or our former general partner.

Due to Related Parties

The balance of amounts due to related parties at December 31, 2003 and 2002 was $27.0 million and $23.3 million, respectively, and was primarily related to crude oil purchased by us but not yet paid as of December 31 of each year.

Transaction Grant Agreements

In connection with our initial public offering, our former general partner, at no cost to us, agreed to transfer, subject to vesting, approximately 400,000 of its affiliates' common units (including distribution equivalent rights attributable to such units) to certain key officers and employees of our former general partner and its affiliates. Under these grants, the common units vested based on attaining a targeted operating surplus for a given year. Approximately 70,000 units vested in 2000, with the remainder in 2001. The value of the units and associated distribution equivalent rights that vested under the Transaction Grant Agreements for all grantees in 2001 were $5.7 million. Although we recorded noncash compensation expenses with respect to these vestings, the compensation expense incurred in connection with these grants was funded by our former general partner, without reimbursement by us.

Performance Option Plan

In connection with the General Partner Transition, 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 375,000 units have been granted. These options vest in 25% increments based upon achieving quarterly distribution levels on our units of $0.525, $0.575, $0.625 and $0.675 ($2.10, $2.30, $2.50 and $2.70, annualized). The first such level was reached, and 25% of the options vested, in 2002. The options will vest in their entirety immediately upon a change in control (as defined in the grant agreements). The original purchase price under the options is $22 per subordinated unit, declining over time in an amount equal to 80% of each quarterly distribution per unit. As of February 17, 2004, the purchase price was $17.30 per unit. The terms of future grants may differ from the existing grants. Because the units underlying the plan were contributed to the general partner, we will have no obligation to reimburse the general partner for the cost of the units upon exercise of the options. At December 31, 2003 approximately 371,875 units were outstanding following the exercise of 3,125 options during 2003.

Stock Option Replacement

In connection with the General Partner Transition, certain members of the management team that had been employed by Plains Resources were transferred to the general partner. At that time, such individuals held in-the-money but unvested stock options in Plains Resources, which were subject to forfeiture because of the transfer of employment. Plains Resources, through its affiliates, agreed to substitute a contingent grant of subordinated units (or common units after conversion) with a value equal to the spread on the unvested options, with distribution equivalent rights from the date of grant. The units vest on the same schedule as the stock options would have vested. The general partner administers the vesting and delivery of the units under the grants. Because the units necessary to satisfy the delivery requirements under the grants are provided by Plains Resources, we have no obligation to reimburse the general partner for the cost of such units.

Benefit Plan

A subsidiary of Plains Resources was, until June 8, 2001, our general partner. On that date, such entity transferred the general partner interest to our current general partner, which effective July 1, 2001, 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, 2003 and 2002, the defined contribution plan expense was approximately $2.6 million and $2.1 million, respectively. For the period July 1 through December 31, 2001, defined contribution plan expense was approximately $1.1 million.

Prior to July 1, 2001, Plains Resources maintained a 401(k) defined contribution plan whereby it matched 100% of an employee's contribution (subject to certain limitations in the plan), with matching contributions being made 50% in cash and 50% in common stock of Plains Resources (the number of shares for the stock match being based on the market value of the common stock at the time the shares were granted). For the period January 1 through June 30, 2001, defined contribution plan expense was $1.0 million.

Note 11—Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "LTIP") for employees and directors of our general partner and its affiliates who perform services for us. The LTIP consists of two components, a restricted ("phantom") unit plan and a unit option plan. The LTIP currently permits the grant of phantom units and unit options covering an aggregate of 1,425,000 common units. The plan is administered by the Compensation Committee of our general partner's board of directors. Our general partner's board of directors in its discretion may terminate the LTIP at any time with respect to any common units for which a grant has not yet been made. Our general partner's board of directors also has the right to alter or amend the LTIP or any part of the plan from time to time, including, subject to any applicable NYSE listing requirements, increasing the number of common units with respect to which awards may be granted; provided, however, that no change in any outstanding grant may be made that would materially impair the rights of the participant without the consent of such participant.

Restricted Unit Plan. A restricted unit is a "phantom" unit that entitles the grantee to receive, upon the vesting of the phantom unit, a common unit (or cash equivalent, depending on the terms of the grant). As of December 31, 2003, aggregate outstanding grants of approximately 1,003,000 have been made to employees, officers and directors of our general partner. As discussed in more detail below, a substantial number of phantom units have recently vested or are expected to vest in the first half of 2004. As of February 17, 2004, giving effect to vested grants, grants of approximately 684,000 unvested phantom units remain outstanding to employees, officers and directors of our general partner. As discussed below, a substantial portion of these phantom units are expected to vest in May 2004. The Compensation Committee may, in the future, make additional grants under the plan to employees and directors containing such terms as the Compensation Committee shall determine.

If a grantee terminates employment or membership on the board for any reason, the grantee's phantom units will be automatically forfeited unless, and to the extent, the Compensation Committee provides otherwise. Common units to be delivered upon the vesting of rights 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. In addition, the Partnership may issue up to 975,000 new common units to satisfy delivery obligations under the grants, less any common units issued upon exercise of unit options under the plan (see below). If we issue new common units upon vesting of the phantom units, the total number of common units outstanding will increase. The Compensation Committee, in its discretion, may grant tandem distribution equivalent rights with respect to phantom units.

The phantom units (other than director grants) granted during the subordination period were subject to the basic restriction that vesting could take place only after and in proportion to any conversion of subordinated units into common units. Certain grants were subject to additional vesting criteria, primarily related to the Partnership's performance. In November 2003, 25% of the outstanding subordinated units converted on a one-for-one basis into common units and the remainder of our subordinated units converted into common units in February 2004. As a result, approximately 35,000 phantom units vested in November 2003, approximately 326,000 phantom units vested in February 2004, and we anticipate that approximately 473,000 additional phantom units will vest in May 2004, subject to the satisfaction of service period requirements. Under generally accepted accounting principles, we are required to recognize an expense when it is considered probable that the financial tests for conversion of subordinated units and required distribution levels will be met and that the phantom units will vest. As of December 31, 2003, we had recorded approximately $28.8 million of compensation expense for the units that vested during 2003 and those that we concluded probable of vesting during 2004. The compensation expense recorded is based upon the actual amounts paid in 2003, or for the unpaid portion, an estimated market price of $33.35 per unit, our share of employment taxes and other related costs.

During 2003, we paid cash in lieu of issuing units for approximately 7,500 of the phantom units that vested during the year and issued approximately 18,000 common units (after netting for taxes). For those units that vested in February 2004, we paid cash in lieu of issuing units for approximately 104,000 of the phantom units and issued approximately 138,000 new common units (after netting for taxes) in connection with such vesting. We anticipate paying cash for approximately 201,000 of the phantom units expected to vest in May 2004, as well as issuing approximately 181,000 new common units (after netting for taxes) in connection with such vesting.

The issuance of the common units pursuant to the restricted unit plan is primarily intended to serve as a means of incentive compensation for performance. Therefore, no consideration will be paid to us by the plan participants upon receipt of the common units.

In 2000, the three non-employee directors of our former general partner were each granted 5,000 phantom units. These units vested in connection with the consummation of the General Partner Transition. Additional grants of 5,000 phantom units were made in 2002 to each non-employee director of our general partner. These units vest in 25% increments on each anniversary of June 8, 2001. The first vesting took place on June 8, 2002.

Unit Option Plan. The Unit Option Plan under our Long-Term Incentive Plan currently permits the grant of options covering common units. No grants have been made under the Unit Option Plan to date. However, the Compensation Committee may, in the future, make grants under the plan to employees and directors containing such terms as the committee shall determine, provided that unit options have an exercise price equal to the fair market value of the units on the date of grant.

Note 12—Commitments and Contingencies

We lease certain real property, equipment and operating facilities under various operating 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, 2003, are summarized below (in millions):

2004	$	12.7
2005	$	11.2
2006	$	8.8
2007	$	5.3
2008	$	2.8
Thereafter	$	0.7

Total lease expense incurred for 2003, 2002 and 2001 was $10.5 million, $8.3 million and $7.4 million, respectively. As is common within the industry and in the ordinary course of business, we have also entered into various operational commitments and agreements related to pipeline operations and to marketing, transportation, terminalling and storage of crude oil and LPG.

Litigation

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the short supply controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the "BIS") of the U.S. Department of Commerce. We have determined that we may have exceeded the quantity of crude oil exports authorized by previous licenses. Export of crude oil in excess of the authorized amounts is a violation of the EAR. On October 18, 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and have received a new license allowing for exports of volumes more than adequately reflecting our anticipated needs. On October 2, 2003, we submitted additional information to the BIS. At this time, we have received no indication whether the BIS intends to charge us with a violation of the EAR or, if so, what penalties would be assessed. As a result, we cannot estimate the ultimate impact of this matter.

Alfons Sperber v. Plains Resources Inc., et. al. On December 18, 2003, a putative class action lawsuit was filed in the Delaware Chancery Court, New Castle County, entitled*Alfons Sperber v. Plains Resources Inc., et al.* This suit, brought on behalf of a putative class of Plains All American Pipeline, L.P. common unit holders, asserts breach of fiduciary duty and breach of contract claims against the Partnership, Plains AAP, L.P., and Plains All American GP LLC and its directors, as well as breach of fiduciary duty claims against Plains Resources Inc. and its directors. The complaint seeks to enjoin or rescind a proposed acquisition of all of the outstanding stock of Plains Resources Inc., as well as declaratory relief, an accounting, disgorgement and the imposition of a constructive trust, and an award of damages, fees, expenses and costs, among other things. The Partnership intends to vigorously defend this lawsuit.

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

Other

The occurrence of a significant event not fully insured or indemnified against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe that 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.

We may experience future releases of crude oil into the environment from our pipeline and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business.

Note 13—Environmental Remediation

In connection with various acquisitions, we have received indemnities from the sellers for environmental exposure, subject to our prior payment of certain threshold amounts. Based on our investigations of the assets acquired in such acquisitions, we have identified several sites that exceed the threshold limitations under the various indemnities. Although we have not yet determined the total cost of remediation of these sites, we believe our indemnification arrangements should prevent such costs from having a material adverse effect on our financial condition, results of operations or cash flows.

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

As of December 31, 2003, we have approximately $6.6 million reserved associated with our remediation obligations. This amount is approximately equal to the threshold amounts the partnership must incur before the sellers' indemnities take effect. Approximately $1.6 million of our environmental reserve is classified as current and $5.0 million is classified as long-term because in many cases, the actual cash expenditures may not occur for up to ten years or more.

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

Note 14—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total(1)
		(in thousands, except per unit data)			
2003					
Revenues	$ 3,281.9	$ 2,709.2	$ 3,053.7	$ 3,545.0	$ 12,589.8
Gross margin	46.7	44.0	38.7	41.2	170.6
Operating income	33.6	31.9	21.0	11.6	98.2
Net income (loss)	24.4	23.4	11.9	(0.2)	59.4
Basic net income (loss) per limited partner unit	0.46	0.42	0.20	(0.03)	1.01
Diluted net income (loss) per limited partner unit	0.46	0.42	0.19	(0.03)	1.00
Cash distributions per common unit(2)	$ 0.550	$ 0.550	$ 0.550	$ 0.563	$ 2.21
2002					
Revenues	$ 1,545.3	$ 1,985.3	$ 2,344.1	$ 2,509.5	$ 8,384.2
Gross margin	31.4	34.5	35.3	39.0	140.2
Operating income	20.8	23.4	23.8	26.7	94.6
Net income	14.3	17.0	16.3	18.9	65.3
Basic and diluted net income per limited partner unit	0.31	0.37	0.33	0.35	1.34
Cash distributions per common unit(2)	$ 0.525	$ 0.538	$ 0.538	$ 0.538	$ 2.14

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

(2)
Represents cash distributions declared per common unit for the period indicated. Distributions were paid in the following calendar quarter.

Note 15—Operating Segments

Our operations consist of two operating segments: (1) Pipeline Operations—engages in interstate and intrastate crude oil pipeline transportation and certain related merchant activities; (2) Gathering, Marketing, Terminalling and Storage Operations—engages in purchases and resales of crude oil and LPG at various points along the distribution chain and the operation of certain terminalling and storage assets. We evaluate segment performance based on (i) segment margin (revenue less purchases and operating expenses), (ii) segment profit (segment margin less general and administrative expenses) and (iii) maintenance capital. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred.

	Pipeline	Gathering Marketing, Terminalling & Storage	Total
		(in millions)	
Twelve Months Ended December 31, 2003			
Revenues:			
External Customers	$ 605.1	$ 11,984.7	$ 12,589.8
Intersegment[(a)]	53.5	0.9	54.5
Total revenues of reportable segments	$ 658.6	$ 11,985.6	$ 12,644.3
Segment margin	$ 109.2	$ 108.2	$ 217.4
General and administrative expenses[(b)]	27.9	45.1	73.0
Segment profit	$ 81.3	$ 63.1	$ 144.4
Capital expenditures	$ 211.9	$ 21.9	$ 233.8
Total assets	$ 1,221.0	$ 874.6	$ 2,095.6
Non-cash SFAS 133 impact[(d)]	$ —	$ 0.4	$ 0.4
Maintenance capital	$ 6.4	$ 1.2	$ 7.6
Twelve Months Ended December 31, 2002			
Revenues:			
External Customers	$ 462.4	$ 7,921.8	$ 8,384.2
Intersegment[(a)]	23.8	—	23.8
Total revenues of reportable segments	$ 486.2	$ 7,921.8	$ 8,408.0
Segment margin	$ 83.9	$ 90.4	$ 174.3
General and administrative expenses[(b)(c)]	13.2	31.5	44.7
Segment profit	$ 70.7	$ 58.9	$ 129.6
Capital expenditures	$ 341.9	$ 23.3	$ 365.2
Total assets	$ 1,030.7	$ 635.9	$ 1,666.6
Non-cash SFAS 133 impact[(d)]	$ —	$ 0.3	$ 0.3
Maintenance capital	$ 3.4	$ 2.6	$ 6.0

Twelve Months Ended December 31, 2001

Revenues:						
External Customers	$	339.9	$	6,528.3	$	6,868.2
Intersegment[(a)]		17.5		—		17.5
Total revenues of reportable segments	$	357.4	$	6,528.3	$	6,885.7
Segment margin	$	71.3	$	71.0	$	142.3
General and administrative expenses[(b)(c)]		12.4		28.5		40.9
Segment profit	$	58.9	$	42.5	$	101.4
Capital expenditures	$	169.8	$	80.4	$	250.2
Total assets	$	472.3	$	788.9	$	1,261.2
Non-cash SFAS 133 impact[(d)]	$	—	$	0.2	$	0.2
Maintenance capital	$	0.5	$	2.9	$	3.4

(a) Intersegment sales were conducted at arms length.

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

(c) In 2002, $1.0 million write-off of deferred acquisition-related costs was excluded as it is not attributable to the segments. Also, $5.7 million of non cash compensation expense in 2001 was excluded as it is not allocated to the segments.

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

(e) The following table reconciles segment profit to consolidated net income (in millions):

	For the year ended December 31,		
	2003	2002	2001
Segment profit	$ 144.4	$ 129.6	$ 101.4
Unallocated general and administrative expenses	—	(1.0)	(5.7)
Depreciation and amortization	(46.8)	(34.1)	(24.3)
Gain on sale of assets	0.6	—	1.0
Interest expense	(35.2)	(29.1)	(29.1)
Interest income and other, net	(3.6)	(0.1)	0.4
Cumulative effect of accounting change	—	—	0.5
Net Income	$ 59.4	$ 65.3	$ 44.2

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):

Revenues	For the Year Ended December 31, 2003	2002
United States	$ 10,536.8	$ 6,941.7
Canada	2,053.0	1,442.5
	$ 12,589.8	$ 8,384.2

Long-Lived Assets	For the Year Ended December 31, 2003	2002
United States	$ 1,039.8	$ 866.9
Canada	316.9	194.1
	$ 1,356.7	$ 1,061.0