PART II

Item 5. *Market For the Registrant's Common Units and Related Unitholder Matters*

The common units, excluding the Class B common units, are listed and traded on the New York Stock Exchange under the symbol "PAA". On February 21, 2003, the market price for the common units was $25.40 per unit and there were approximately 17,126 record holders and beneficial owners (held in street name).

The following table sets forth high and low sales prices for the common units and the cash distributions paid per common unit for the periods indicated:

	Common Unit Price Range		
	High	**Low**	**Cash Distributions**
2001			
1st Quarter	$ 23.63	$ 19.06	$ 0.4750
2nd Quarter	28.00	22.15	0.5000
3rd Quarter	29.65	23.10	0.5125
4th Quarter	28.00	24.35	0.5125
2002			
1st Quarter	$ 26.79	$ 23.60	$ 0.5250
2nd Quarter	27.30	24.60	0.5375
3rd Quarter	26.38	19.54	0.5375
4th Quarter	24.44	22.04	0.5375

The Class B common units are pari passu with common units with respect to quarterly 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 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, the Class B units have the same voting rights as the common units. As of February 21, 2003, there was one Class B unitholder. We have also issued and outstanding 10,029,619 subordinated units, for which there is no established public trading market.

Cash Distribution Policy

We distribute on a quarterly basis all of our available cash. Available cash generally means, for any of our fiscal quarters, all cash on hand at the end of the quarter less the amount of cash reserves that is necessary or appropriate in the reasonable discretion of our general partner to:

- provide for the proper conduct of our business;

- comply with applicable law, any of our debt instruments or other agreements; or

- provide funds for distributions to unitholders and our general partner for any one or more of the next four quarters.

Minimum quarterly distributions are $0.45 for each full fiscal quarter. Distributions of available cash to the holders of subordinated units are subject to the prior rights of the holders of common units to receive the minimum quarterly distributions for each quarter during the subordination period, and to receive any arrearages in the distribution of minimum quarterly distributions on the common units for prior quarters during the subordination period. In addition to distributions on its 2% general partner interest, 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 our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, 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. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Under the terms of our credit facility agreements, we are prohibited from declaring or paying any distribution to unitholders if a default or event of default (as defined in such agreements) exists. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Long-term Debt."

Conversion of Subordinated Units

The subordination period will end if certain financial tests contained in the partnership agreement are met for three consecutive four-quarter periods (the "testing period"), but no sooner than December 31, 2003. During the first quarter after the end of the subordination period, all of the subordinated units will convert into common units. Early conversion of a portion of the subordinated units may occur if the testing period is satisfied before December 31, 2003. We are now in the testing period and, if we continue to meet the requirements, 25% of the subordinated units will convert into common units in the fourth quarter of 2003 and the remainder will convert in the first quarter of 2004. Our ability to meet these requirements is subject to a number of economic and operational contingencies. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Factors Related to Our Business" and "Forward Looking Statements" at the beginning of this report.

Item 6. *Selected Financial and Operating Data*

The historical financial information below for Plains All American Pipeline, L.P. was derived from our audited consolidated financial statements as of December 31, 2002, 2001, 2000, 1999 and 1998, and for the years ended December 31, 2002, 2001, 2000 and 1999 and for the period from November 23, 1998, through December 31, 1998. The financial information below for our predecessor was derived from the audited combined financial statements of our predecessor, for the period from January 1, 1998, through November 22, 1998, including the notes thereto. The operating data for all periods is derived from our records as well as those of our predecessor. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, included elsewhere in this report, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

"EBITDA" means earnings before interest expense, income taxes, depreciation and amortization. Adjusted EBITDA excludes the impact of unusual and non-recurring items and the impact of Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." Adjusted EBITDA is not presented in accordance with generally accepted accounting principles and is not intended to be used in lieu of GAAP presentations of results of operations or cash provided by operating activities. Adjusted EBITDA is presented because we believe it provides additional information with respect to our ability to meet our future debt service, capital expenditures and working capital requirements, and is commonly used by debt holders to analyze company performance. When evaluating Adjusted EBITDA, investors should consider, among other factors:

- increasing or decreasing trends in Adjusted EBITDA;
- whether Adjusted EBITDA has remained at positive levels historically; and
- how Adjusted EBITDA compares to levels of interest expense and long-term debt.

However, Adjusted EBITDA does not necessarily indicate whether cash flow will be sufficient for such items as working capital requirements, capital expenditures or to react to changes in our industry or the economy in general, as certain functional or legal requirements of our business may require us to use our available funds for other purposes. These measures may not be comparable to measures of other companies.

						Predecessor
	Year Ended December 31,				November 23 to December 31, 1998	January 1 to November 22, 1998
	2002	2001	2000	1999		
	(in millions except per unit data)					
Statement of Operations Data:						
Revenues	$8,384.2	$6,868.2	$6,641.2	$10,910.4	$ 398.9	$ 3,118.4
Cost of sales and operations	8,209.9	6,720.9	6,506.5	10,800.1	391.4	3,087.4
Unauthorized trading losses and related expenses	—	—	7.0	166.4	2.4	4.7
Inventory valuation adjustment	—	5.0	—	—	—	—
Gross margin	174.3	142.3	127.7	(56.1)	5.1	26.3
General and administrative expenses	45.7	46.6	40.8	23.2	0.8	4.5
Depreciation and amortization	34.0	24.3	24.5	17.3	1.2	4.2
Restructuring expense	—	—	—	1.4	—	—
Total expenses	79.7	70.9	65.3	41.9	2.0	8.7
Operating income (loss)	94.6	71.4	62.4	(98.0)	3.1	17.6
Interest expense	(29.1)	(29.1)	(28.7)	(21.1)	(1.4)	(11.3)
Gain on sale of assets	—	1.0	48.2	16.4	—	—
Interest and other income (loss)	(0.2)	0.4	10.8	0.9	0.1	0.6
Income (loss) before provision in lieu of income taxes, extraordinary item and cumulative effect of accounting change	65.3	43.7	92.7	(101.8)	1.8	6.9
Provision in lieu of income taxes	—	—	—	—	—	2.6
Income (loss) before extraordinary item and cumulative effect of accounting change	$ 65.3	$ 43.7	$ 92.7	(101.8)	$ 1.8	$ 4.3

Basic and diluted net income (loss) per limited partner unit before extraordinary item and cumulative effect of accounting change	$ 1.34	$ 1.12	$ 2.64	$ (3.16)	$ 0.06	$ 0.25
Weighted average number of limited partner units outstanding	45.5	37.5	34.4	31.6	30.1	17.0
Balance Sheet Data: (at end of period):						
Working capital[(1)]	$ (34.3)	$ 52.9	$ 47.1	$ 101.5	$ 2.2	N/A
Total assets	1,666.6	1,261.2	885.8	1,223.0	607.2	N/A
Related party debt—Long-term	—	—	—	114.0	—	N/A
Long-term debt[(2)]	509.7	354.7	320.0	310.1	175.0	N/A
Partners' capital	511.6	402.8	214.0	193.0	270.5	N/A
Other Data:						
Adjusted EBITDA[(3)]	$ 130.4	$ 109.6	$ 103.0	$ 89.1	$ 6.7	$ 27.0
Maintenance capital expenditures	6.0	3.4	1.8	1.7	0.2	1.5
Net cash provided by (used in) operating activities	173.9	(30.0)	(33.5)	(71.2)	7.2	21.4
Net cash provided by (used in) investing activities	(363.8)	(249.5)	211.0	(186.1)	(3.1)	(399.6)
Net cash provided by (used in) financing activities	189.5	279.5	(227.8)	305.6	1.4	386.2

(Table continued on following page)

	Year Ended December 31,				November 23 to December 31, 1998	Predecessor January 1 to November 22, 1998
	2002	2001	2000	1999		
	(in thousands)					
Operating Data:						
Volumes (barrels per day):						
Pipeline segment:						
Tariff activities						
All American	65	69	74	103	110	114
Basin	93	N/A	N/A	N/A	N/A	N/A
Other domestic	228	144	130	61	—	—
Canada	187	132	N/A	N/A	N/A	N/A
Margin activities	73	61	60	54	51	49
Total	646	406	264	218	161	163
Gathering, marketing, terminalling and storage segment:						
Lease gathering	410	348	262	265	126	87
Bulk purchases	80	46	28	138	134	95
Total	490	394	290	403	260	182
Cushing terminal throughput	110	94	59	72	62	81

(1) At December 31, 1999, working capital included $37.9 million of pipeline linefill and $103.6 million for a segment of the All American Pipeline, both of which were sold in the first quarter of 2000.
(2) Includes current maturities of long-term debt of $9.0 million, $3.0 million, $0.0 million, $50.7 million and $0.0 million at December 31, 2002, 2001, 2000, 1999 and 1998, respectively. In addition, long-term debt in 1999 excludes related party debt.
(3) For the year ended December 31, 2002, Adjusted EBITDA excludes the impact of:

- noncash reserve for potential environmental obligations of $1.2 million;
- noncash SFAS 133 gain of $0.3 million; and
- write-off of deferred acquisition-related costs of $1.0 million.

For the year ended December 31, 2001, Adjusted EBITDA excludes the impact of:

- noncash reserve for receivables of $3.0 million;
- noncash cumulative effect of accounting change gain of $0.5 million;
- noncash SFAS 133 gain of $0.2 million;
- noncash compensation expense of $5.7 million;
- gain on sale of assets of $1.0 million; and
- noncash mark-to-market inventory charge of $5.0 million.

For the year ended December 31, 2000, Adjusted EBITDA excludes the impact of:

- extraordinary loss on early extinguishment of debt of $15.1 million;
- unauthorized trading losses and related expenses of $7.0 million;
- noncash reserve for receivables of $5.0 million;
- noncash compensation expense of $3.1 million;
- gain on sale of assets of $48.2 million; and
- gain on interest rate swap of $9.7 million.

For the year ended December 31, 1999, Adjusted EBITDA excludes the impact of:

- unauthorized trading losses and related expenses of $166.4 million;
- restructuring expense of $1.4 million;
- noncash compensation expense of $1.0 million;
- gain on sale of assets of $16.4 million; and
- extraordinary loss on early extinguishment of debt of $1.5 million.

For the period from November 23 to December 31, 1998, Adjusted EBITDA excludes the impact of:

- Unauthorized trading losses and related expenses of $2.4 million.

For the period from January 1 to November 22, 1998, Adjusted EBITDA excludes the impact of:

- Unauthorized trading losses and related expenses of $4.7 million.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

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

Overview

Plains All American Pipeline, L.P. is a Delaware limited partnership (the "Partnership") formed in September of 1998. On November 23, 1998, we completed our initial public offering ("IPO") and the transactions whereby we became the successor to the midstream crude oil business and assets of Plains Resources Inc. and its wholly owned subsidiaries ("Plains Resources"). Immediately after our IPO, Plains Resources Inc. owned 100% of our general partner interest and an overall effective ownership in the Partnership of 57% (including its 2% general partner interest and common and subordinated units owned). As discussed below, Plains Resources' effective ownership interest in the Partnership has been reduced substantially.

In May 2001, senior management and a group of financial investors entered into a transaction with Plains Resources to acquire majority control of our general partner and a majority of the outstanding subordinated units. The transaction closed in June 2001 and, for purposes of this report, is referred to as the "General Partner Transition." As a result of this transaction and subsequent equity offerings, Plains Resources' overall effective ownership has been reduced to approximately 25%. See Item 12. "Security Ownership of Certain Beneficial Owners and Management." In addition, certain officers of the general partner who previously were also officers of Plains Resources terminated their affiliation with Plains Resources and as a result now devote 100% of their efforts to the management of the Partnership.

Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., All American Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil pipeline transportation as well as gathering, marketing, terminalling and storage of crude oil and liquefied petroleum gas ("LPG"). We own an extensive network in the United States and Canada of pipeline transportation, storage and gathering assets in key oil producing basins and at major market hubs. Our operations are conducted primarily in Texas, Oklahoma, California, Louisiana and the Canadian provinces of Alberta and Saskatchewan and consist of two operating segments: (i) Pipeline Operations and (ii) Gathering, Marketing, Terminalling and Storage Operations. Our operating segments are discussed further in the "Results of Operations" section below.

Acquisitions

We completed a number of acquisitions in 2002 and 2001 that have impacted the results of operations and liquidity discussed herein. The following acquisitions were accounted for, and the purchase price was allocated, in accordance with the purchase method of accounting. We adopted Statement of Financial Accounting Standards ("SFAS") No. 141, "Business Combinations" in 2001 and followed the provisions of that statement for all business combinations initiated after June 30, 2001. Our ongoing acquisition activity is discussed further in "Liquidity and Capital Resources" below.

Shell West Texas Assets

On August 1, 2002, we acquired 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 from Shell Pipeline Company LP and Equilon Enterprises LLC (the "Shell acquisition"). The primary assets included in the transaction are interests in the Basin Pipeline System, the Permian Basin Gathering System and the Rancho Pipeline System. 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. We are in the process of evaluating certain estimates made in the purchase price allocation, including costs associated with the shutdown of the Rancho Pipeline System; thus the allocation is subject to refinement.

The acquired assets are primarily fee-based mainline crude oil pipeline transportation assets that gather crude oil in the Permian Basin and transport the crude oil to major market locations in the Mid-Continent and Gulf Coast regions. The Permian Basin has long been one of the most stable crude oil producing regions in the United States, dating back to the 1930s. The acquired assets complement our existing asset infrastructure in West Texas and represent a transportation link to Cushing, Oklahoma, where we provide storage and terminalling services. In addition, we believe that the Basin Pipeline System is poised to benefit from potential shut-downs of refineries and other pipelines due to the shifting market dynamics in the West Texas area. The Rancho Pipeline System will be taken out of service in March 2003, pursuant to the operating agreement. See Items 1 and 2. “Business and Properties—Pipeline Operations—Pipeline Assets—Southwest U.S.—Rancho Pipeline System.”

For more information on this transaction, as well as historical financial information on the businesses acquired and pro forma financial information reflecting the acquisition of the businesses, please refer to our Form 8-K dated August 9, 2002, which was filed with the Securities and Exchange Commission.

Coast Energy Group and Lantern Petroleum

In March 2002, we completed the acquisition of substantially all of the domestic crude oil pipeline, gathering and marketing assets of Coast Energy Group and Lantern Petroleum, divisions of Cornerstone Propane Partners, L.P., for approximately $8.3 million in cash net of liabilities assumed and transaction costs (the “Cornerstone acquisition”). The principal assets acquired are located in West Texas and include several gathering lines, crude oil contracts and a small truck and trailer fleet. The acquired assets serve to expand our core market in West Texas and give us access to more volumes in the area.

Butte Pipe Line Company

In February 2002, we acquired an approximate 22% equity interest in Butte Pipe Line Company from Murphy Ventures, a subsidiary of Murphy Oil Corporation (the “Butte acquisition”). The total cost of the acquisition, including various transaction and related expenses, was approximately $7.6 million. Butte Pipe Line Company owns the 373-mile Butte Pipeline System, principally a mainline system, that runs from Baker, Montana to Guernsey, Wyoming. The Butte Pipeline is connected to the Poplar Pipeline System, which in turn is connected to the Wascana Pipeline System, which is 100% wholly owned by us. We believe these pipeline systems will play an important role in moving increasing volumes of Canadian crude oil into markets in the United States.

Wapella Pipeline System

In December 2001, we consummated the acquisition of the Wapella Pipeline System from private investors for approximately $12.0 million, including transaction costs (the “Wapella acquisition”). The entire purchase price was allocated to property and equipment. The system is located in southeastern Saskatchewan and southwestern Manitoba and further expands our market in Canada. In 2001, the Wapella Pipeline System delivered approximately 11,000 barrels per day of crude oil to the Enbridge Pipeline at Cromer, Manitoba. The acquisition also includes approximately 21,500 barrels of crude oil storage capacity located along the system, as well as a truck terminal.

CANPET Energy Group

In July 2001, we acquired the assets of CANPET Energy Group Inc., a Calgary-based Canadian crude oil and LPG marketing company (the “CANPET acquisition”), for approximately $42.0 million plus excess inventory at the closing date of approximately $25.0 million. Approximately $18.0 million of the purchase price, payable in common units, 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 had they been outstanding since the acquisition was consummated. See Note 8 —“Partners’ Capital and Distributions” in the “Notes to the Consolidated Financial Statements.” 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. 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 establishment of a Canadian operation that substantially mirrors our operations in the United States. The purchase price, as adjusted post-closing, was allocated as follows (in millions):

Inventory	$	28.1
Goodwill		11.1
Intangible assets (contracts)		1.0
Pipeline linefill		4.3
Crude oil gathering, terminalling and other assets		5.1
Total	$	49.6

Murphy Oil Company Ltd. Midstream Operations

In May 2001, we completed the acquisition of substantially all of the Canadian crude oil pipeline, gathering, storage and terminalling assets of Murphy Oil Company Ltd. for approximately $161.0 million in cash ($158.4 million after post-closing adjustments), including financing and transaction costs (the “Murphy acquisition”). Initial financing for the acquisition was provided through borrowings under our credit facilities. The purchase price included $6.5 million for excess inventory in the pipeline systems. The principal assets acquired include approximately 560 miles of crude oil and condensate 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 establishment of a Canadian operation that substantially mirrors 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 acquisition, these volumes averaged 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

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities, as well as the disclosure of contingent assets and liabilities, at the date of the financial statements. Such estimates and assumptions also affect the reported amounts of revenues and expenses during the reporting period. Although we believe these estimates are reasonable, actual results could differ from these estimates. The critical accounting policies that we have identified are discussed below.

Depreciation, Amortization and Impairment of Long-Lived Assets

We calculate our depreciation and amortization based on estimated useful lives and salvage values of our assets. When assets are put into service, we make estimates with respect to useful lives that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization.

Additionally, we assess our long-lived assets for possible impairment whenever events or changes in circumstances indicate that the carrying value of the assets may not be recoverable. Such indicators include changes in our business plans, a change in the extent or manner in which a long-lived asset is being used or in its physical condition, or a current expectation that, more likely than not, a long-lived asset will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. If the carrying value of an asset exceeds the future undiscounted cash flows expected from the asset, an impairment charge would be recorded for the excess of the carrying value of the asset over its fair value. Determination as to whether and how much an asset is impaired would necessarily involve numerous management estimates. Any impairment reviews and calculations would be based on assumptions that are consistent with our business plans and long-term investment decisions.

Allowance for Doubtful Accounts Receivable

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 uncollected amounts involve billing delays and discrepancies or disputes as to the appropriate price, volumes or quality of crude oil delivered, received or exchanged. We also attempt to monitor changes in the creditworthiness of our customers as a result of developments related to each customer, the industry as a whole and the general economy. Based on these analyses, we have established an allowance for doubtful accounts receivable and consider the reserve adequate, however, there is no assurance that actual amounts will not vary significantly from estimated amounts.

Revenue and Expense Accruals

We routinely make accruals for both revenues and expenses due to the timing of compiling billing information, receiving third party information and reconciling our records with those of third parties. In situations where we are required to make mark-to-market estimates pursuant to SFAS 133, the estimates of gains or losses at a particular period end do not reflect the end results of particular transactions, and will most likely not reflect the actual gain or loss at the conclusion of a transaction. We reflect estimates for these items based on our internal records and information from third parties. A portion of the estimates we use are based on internal models or models of third parties because they are not quoted on a national market. Additionally, values may vary among different models and may not be reflective of the price at which they can be settled due to the lack of a liquid market. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

Liability and Contingency Accruals

We accrue reserves for contingent liabilities including, but not limited to, environmental remediation and potential legal claims. Accruals are made when our assessment indicates that it is probable that a liability has occurred and the amount of liability can be reasonably estimated. Our estimates are based on all known facts at the time and our assessment of the ultimate outcome. These estimates will be increased or decreased as additional information is obtained or resolution is achieved.

Determination of Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets

In conjunction with each acquisition, we must allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. We also estimate the amount of transaction costs that will be incurred in connection with each acquisition. As additional information becomes available, we may adjust the original estimates within a short time subsequent to the acquisition. In addition, in conjunction with the recent adoption of SFAS 141, we are required to recognize intangible assets separately from goodwill. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment. The impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of market conditions including pricing, demand, competition, operating costs and other factors. Intangible assets with finite lives are amortized over the estimated useful life determined by management. Determining the fair value of assets and liabilities acquired, as well as intangible assets that relate to such items as relationships, contracts, and industry expertise involves professional judgment and is ultimately based on acquisition models and management's assessment of the value of the assets acquired. We believe our estimates for these items are reasonable, but there is no assurance that actual amounts will not vary significantly from estimated amounts.

Results of Operations

Analysis of Three Years Ended December 31, 2002

Our operating results were impacted by acquisitions made during 2002 and 2001. These acquisitions include the assets acquired in the Shell acquisition, which are included in our results of operations as of August 1, 2002, and the Murphy and CANPET acquisitions, which are included in our results of operations as of April 1, 2001 and July 1, 2001, respectively.

We reported net income for the year ended December 31, 2002, of $65.3 million on total revenues of $8.4 billion compared to net income for the same period in 2001 and 2000 of $44.2 million and $77.5 million on total revenues of $6.9 billion and $6.6 billion, respectively. When we evaluate our results for performance against expectations, public guidance and trend analysis, we exclude the impact of SFAS 133 resulting from (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. The majority of these instruments serve as economic hedges which offset future physical positions not reflected in current results. Therefore, the SFAS 133 adjustment to net income is not a complete depiction of the economic substance of the transaction, as it only represents the derivative side of these transactions and does not take into account the offsetting physical position. Also, the impact will vary from quarter to quarter based on market prices at the end of the quarter. In addition, we exclude the impact of other unusual or nonrecurring items within each period.

The following table reconciles our reported net income to our net income before unusual or nonrecurring items and the impact of SFAS 133 (in millions):

	Year Ended December 31,		
	2002	**2001**	**2000**
Reported Net Income	$ 65.3	$ 44.2	$ 77.5
Write-off of deferred acquisition-related costs	1.0	—	—
Noncash reserve for potential environmental obligations	1.2	—	—
Noncash mark-to-market inventory charge	—	5.0	—
Noncash compensation expense	—	5.7	3.1
Gain on sale of assets	—	(1.0)	(48.2)
Gain on interest rate swap	—	—	(9.7)
Extraordinary loss on early extinguishment of debt	—	—	15.1
Unauthorized trading losses and related expenses	—	—	7.0
Noncash reserve for receivables	—	3.0	5.0
Noncash amortization of debt issues cost	—	—	4.6
Noncash cumulative effect of accounting change	—	(0.5)	—
Noncash SFAS 133 adjustment	(0.3)	(0.2)	—

Net Income before unusual or nonrecurring items and the impact of SFAS 133	$ 67.2	$ 56.2	$ 54.4

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

Pipeline Operations

We own and operate over 5,600 miles of gathering and mainline crude oil pipelines located throughout the United States and Canada. Our activities from pipeline operations generally consist of transporting volumes of crude oil for a fee, third-party leases of pipeline capacity, barrel exchanges and buy/sell arrangements. We also use our pipelines in our merchant activities conducted under our gathering and marketing business. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The gross margin generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable costs of operating the pipeline. Gross margin from our pipeline capacity leases, barrel exchanges and buy/sell arrangements generally reflect a negotiated amount. The following table sets forth our operating results from our Pipeline Operations segment for the periods indicated:

	Year ended December 31,		
	2002	**2001**	**2000**
Operating Results (in millions):			
Revenues (including intersegment)	$ 486.2	$ 357.4	$ 574.4
Gross margin	$ 83.9	$ 71.3	$ 51.8
General and administrative expenses[1]	13.2	12.4	12.7
Gross profit	$ 70.7	$ 58.9	$ 39.1
Average Daily Volumes (thousands of barrels per day)[2]:			
Tariff activities			
All American	65	69	74
Basin	93	—	—
Other domestic	228	144	130
Canada[3]	187	132	—
Merchant margin activities	73	61	60
Total	646	406	264

(1) General and Administrative ("G&A") expenses reflect direct costs attributable to each segment and an allocation of other G&A expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for 2001 and 2000 to conform to the refined presentation used in 2002. The proportional allocations by segment will continue to be based on the business activities that exist during each period.

(2) Volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition.
(3) 2001 volume information has been adjusted for consistency of comparison with 2002 presentation.

As discussed above, we have completed a number of acquisitions in 2002 and 2001 that have impacted the results of operations herein. The following table adjusts our total average daily volumes for acquisitions made in each period for comparison purposes:

	Year ended December 31,		
	2002	2001	2000
	(barrels in thousands)		
Total average daily volumes[1]	646	406	264
Less volumes from:			
2002 Acquisitions[2]	(171)	—	—
2001 Acquisitions[2][3]	(193)	(134)	—
Total adjusted average daily volumes	282	272	264

(1) Volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition.
(2) The 2002 acquisitions include the Shell acquisition and Butte acquisition. The 2001 acquisitions includes the Murphy acquisition and other minor acquisitions.
(3) The increase in average daily volumes from 2001 to 2002 is primarily due to the inclusion of the Murphy acquisition for a full year in 2002 compared to only a portion of the year in 2001.

Adjusted average daily volumes transported on our pipelines increased approximately 10,000 barrels per day for the year ended December 31, 2002 as compared to the year ended December 31, 2001. The increase was primarily due to higher volumes from our merchant activities partially offset by an approximate 4,000 barrel per day decrease in our All American tariff volumes attributable to California outer continental shelf ("OCS") production and various small decreases on other domestic pipelines. Volumes from the Santa Ynez and Point Arguello fields, both offshore California, have steadily declined from 1995 through 2002. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.1 million, based on the 2002 average tariff rate. Adjusted average daily volumes transported on our pipelines increased approximately 8,000 barrels per day for the year ended December 31, 2001 as compared to the year ended December 31, 2000. The increase was primarily related to increases in the volumes transported on the West Texas Gathering system and various other domestic pipelines partially offset by an approximate 4,500 barrel per day decrease in our All American tariff volumes attributable to California OCS production.

As discussed above, the revenues from our pipeline operations are comprised of pipeline margin revenue from our merchant activities and tariff and fee revenues from volumes transported on our pipelines. Tariffs are typically indexed to the Producer Price Index. The following table details our Pipeline Operations revenues and adjusts our tariff and fee revenue for acquisitions made in each period for comparison purposes:

	Year Ended December 31,		
	2002	2001	2000
		(in millions)	
Pipeline margin revenue	$ 382.5	$ 288.0	$ 515.6
Tariff and fee revenue	103.7	69.4	58.8
Total pipeline operations revenue	$ 486.2	$ 357.4	$ 574.4
Adjustments to tariff and fee revenue for acquisitions			
Tariff and fee revenue	$ 103.7	$ 69.4	$ 58.8
Less revenue from:			
2002 acquisitions	(23.1)	—	—
2001 acquisitions[1]	(21.6)	(9.9)	—
Total adjusted tariff and fee revenue	$ 59.0	$ 59.5	$ 58.8

(1) The increase in revenue from 2001 to 2002 is primarily due to the inclusion of the Murphy acquisition for a full year in 2002 and increases in the tariffs of certain pipeline systems acquired in the Murphy acquisition.

Pipeline margin revenues from our merchant activities were approximately $382.5 million for the year ended December 31, 2002 compared to $288.0 million and $515.6 million for the years ending December 31, 2001 and 2000, respectively. The increase in 2002 revenues over the prior year period is primarily related to our merchant activities on our San Joaquin Valley gathering system. This increase was related to both increased volumes and higher average prices on our buy/sell arrangements in the 2002 period. However, this business is a margin business and although revenues and cost of sales are impacted by the absolute level of crude oil prices, crude oil prices have a limited impact on gross margin. Similarly, the decrease in revenues from our merchant activities for the year ended December 31, 2001 from the year ended December 31, 2000 was related to our merchant activities on our San Joaquin Valley gathering system. The decrease in this period was related to lower volumes of buy/sell arrangements coupled with lower average prices on those arrangements in the 2001 period compared to the 2000 period, as well as a decrease in activity due to the sale of a segment of the All American Pipeline in March 2000. Adjusted tariff and fee revenue was relatively flat for all of the comparable periods as the decrease in volumes attributable to OCS production was offset in each period by other increases, including increases in the tariffs for OCS volumes transported.

Gross margin from pipeline operations was $83.9 million for the year ended December 31, 2002 compared to $71.3 million and $51.8 million for the years ended December 31, 2001 and 2000, respectively. The increase of approximately $12.6 million in 2002 over 2001 resulted primarily from our tariff and fee related activities and was due to the following offsetting items:

- increased volumes on our U.S. pipelines resulting from the businesses acquired during 2002
- increased volumes on our Canadian pipelines due to the inclusion of the pipelines results for the entire 2002 period compared to only a portion of 2001
- a decrease in our volumes attributable to California OCS production that was generally offset with an increase in the tariff per barrel of OCS production transported
- an increase in operating expenses to $40.1 million in the 2002 period from $19.4 million in the 2001 period.

The increase in operating expenses was primarily related to the acquisition of various businesses in 2002 and late 2001 and the inclusion of the results of the Murphy acquisition for all of 2002 compared to only a portion of 2001. Operating expense for the 2002 period also includes a $1.2 million noncash charge associated with the establishment of a liability for potential cleanup of environmental conditions associated with our 1999 acquisitions. We reassessed the previous investigations and completed environmental studies during 2002, and remediation activities are on-going. This amount is approximately equal to the threshold amounts the partnership must incur before the sellers' indemnities take effect. In many cases, the actual cash expenditures may not occur for ten years.

The increase in pipeline gross margin of $19.5 million in the 2001 period compared to the 2000 period is primarily attributable to increased margin from our tariff and fee related activities. The increase in our tariff and fee related activities were primarily due to the impact of the Canadian acquisitions. Excluding the Canadian acquisitions, gross margin from pipeline operations would have increased approximately 8%, due to slightly higher volumes and tariffs, while maintaining operating expenses at a fairly constant level.

General and administrative expense ("G&A") includes the costs directly associated with the segment, as well as a portion of corporate overhead costs considered allocable. See—"Other Income and Expenses—Unallocated G&A Expense." G&A expense related to our pipeline operations was $13.2 million for the year ended December 31, 2002 compared to $12.4 million and $12.7 million for the years ended December 31, 2001 and 2000, respectively. The increase in G&A expense of approximately $0.8 million in the 2002 period was partially due to increased costs from the assets acquired in the Canadian acquisitions due to the inclusion of those assets for the entire 2002 period compared to only a portion of 2001. G&A expense related to pipeline operations decreased approximately $0.3 million in the year ended December 31, 2001 from the year ended December 31, 2000. The decrease was primarily related to lower reserves for potentially uncollectible receivables included in G&A in the 2001 period. This decrease was partially offset by G&A expense of approximately $0.7 million from the assets acquired in the Canadian acquisition and increased personnel costs associated with the General Partner Transition.

Gathering, Marketing, Terminalling and Storage Operations

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased barrels plus the sale of additional barrels exchanged through buy/sell arrangements entered into to enhance the margins of the gathered and bulk-purchased crude oil. Gross margin from our gathering and marketing activities is dependent on our ability to sell crude oil at a price in excess of our aggregate cost. These operations are margin businesses, and are not directly affected by the absolute level of crude oil prices, but are affected by overall levels of supply and demand for crude oil and fluctuations in market-related indices. Accordingly, an increase or decrease in revenues is not necessarily an indication of segment performance.

We own and operate approximately 22.7 million barrels of above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. Cushing, which we refer to as the Cushing Interchange, is one of the largest crude oil market hubs in the United States and the designated delivery point for New York Mercantile Exchange, or NYMEX, crude oil futures contracts. Terminals are facilities where crude oil is transferred to or from storage or a transportation system, such as a pipeline, to another transportation system, such as trucks or another pipeline. The operation of these facilities is called "terminalling." Gross margin from terminalling and storage activities is dependent on the throughput volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. We also use our storage tanks to counter-cyclically balance our gathering and marketing operations and to execute different hedging strategies to stabilize margins and reduce the negative impact of crude oil market volatility.

During periods when supply exceeds the demand for crude oil, the market for crude oil is often in contango, meaning that the price of crude oil for future deliveries is higher than current prices. A contango market has a generally negative impact on marketing margins, but is favorable to the storage business, because storage owners at major trading locations (such as the Cushing Interchange) can simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. When there is a higher demand than supply of crude oil in the near term, the market is backward, meaning that the price of crude oil for future deliveries is lower than current prices. A backwardated market has a positive impact on marketing margins because crude oil gatherers can capture a premium for prompt deliveries. In this environment, there is little incentive to store crude oil, as current prices are above future delivery prices. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow.

We establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation with respect to futures contracts on the NYMEX and over-the-counter. Through these transactions, we establish on a monthly basis a position that is substantially balanced between crude oil purchases and sales and future delivery obligations. We purchase crude oil on both a fixed and floating price basis. As fixed price barrels are purchased, we enter into sales arrangements with refiners, trade partners or on the NYMEX, which establishes a margin and protects us against future price fluctuations. When floating price barrels are purchased, we match those contracts with similar type sales agreements with our customers, or likewise establish a hedge position using the NYMEX futures market. From time to time, we enter into arrangements that expose us to basis risk. Basis risk occurs when crude oil is purchased based on a crude oil specification and location that differs from the countervailing sales arrangement. In order to protect profits involving our physical assets and to manage risks associated with our crude purchase obligations, we use derivative instruments. Except for pre-defined inventory transactions as discussed below, our policy is only to purchase crude oil for which we have a market and to structure our sales contracts so that crude oil price fluctuations do not materially affect the gross margin which we receive. In November 1999, we discovered that this policy was violated. See Items 1 and 2. “Business and Properties—Unauthorized Trading Losses”. Except for crude oil inventory transactions that do not exceed 500,000 barrels, we do not acquire and hold crude oil futures contracts or other derivative products for the purpose of speculating on crude oil price changes that might expose us to indeterminable losses. Similarly, while we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 200,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations.

The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage operations segment for the periods indicated:

	Year Ended December 31,		
	2002	**2001**	**2000**
Operating Results (in millions):			
Revenues	$ 7,921.8	$ 6,528.3	$ 6,135.5
Gross margin	$ 90.4	$ 71.0	$ 75.9
General and administrative expenses[1]	31.5	28.5	25.0
Gross profit	$ 58.9	$ 42.5	$ 50.9
Average Daily Volumes (thousands of barrels per day)[2]:			
Lease gathering	410	348	262
Bulk purchases	80	46	28
Total	490	394	290
Terminal throughput[3]	110	94	59
Storage leased to third parties, monthly average	1,067	2,136	1,437

volumes(3)(4)

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(1) G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. For comparison purposes, we have reclassified G&A expenses by segment for all periods presented to conform to the refined presentation used in 2002. The proportional allocations by segment will continue to be based on the business activities that exist during each period.

(2) Volumes associated with acquisitions represent weighted average daily amounts during the year of acquisition.
(3) Throughput and storage amounts for Cushing facility.
(4) The level of tankage at Cushing that we allocate for our arbitrage activities (and therefore is not available for lease to third parties) varies throughout crude oil price cycles.

Average daily volumes of crude oil gathered from producers, using our assets or third-party assets, totaled approximately 410,000 barrels per day for the year ended December 31, 2002 compared to 348,000 barrels per day and 262,000 barrels per day for the years ended December 31, 2001 and 2000, respectively. Average daily volumes of crude oil purchased in bulk, primarily at major trading locations, for each of the three years in the period ending December 31, 2002, totaled approximately 80,000 barrels per day, 46,000 barrels per day and 28,000 barrels per day, respectively. Storage leased to third parties at our Cushing Terminal decreased to an average of 1.1 million barrels per month for the year ended December 31, 2002 from an average of 2.1 million barrels per month and 1.4 million barrels per month in the years ended December 31, 2001 and 2000, respectively. Average storage leased to third parties decreased during the period as we used an increased amount of our capacity for our own account due to contango market activities and our hedging strategies in the current year period. A contango market exists when oil prices for future deliveries are higher than current prices thereby making it profitable to store crude oil for future delivery. Terminal throughput volumes at our Cushing terminal averaged approximately 110,000, 94,000 and 59,000 barrels per day for the years ended December 31, 2002, 2001 and 2000, respectively.

Revenues from our gathering, marketing, terminalling and storage operations in each of the three years in the period ended December 31, 2002 totaled approximately $7.9 billion, $6.5 billion and $6.1 billion, respectively. The increase in 2002 resulted from higher average volumes from our Canadian and U.S. operations. Revenues from our Canadian operations were approximately $1.6 billion for the 2002 period compared to $0.8 billion in 2001. The increase was primarily related to the inclusion of the CANPET acquisition for all of 2002 compared to only a portion of 2001. This resulted in an increase in 2002 gathered volumes of approximately 47,000 barrels per day and bulk purchases of approximately 18,000 barrels per day over the 2001 period. The remaining increase was primarily related to higher U.S. volumes during 2002. The average NYMEX settlement price for crude oil was $26.10 per barrel in 2002 compared to $25.98 per barrel in 2001. The increase in 2001 as compared to 2000 was primarily due to the impact of the Canadian acquisitions offset by lower oil prices in the 2001 period. The average NYMEX settlement price for crude oil was $30.25 per barrel in 2000. As noted previously, revenues are also impacted by buy/sell arrangements entered into to enhance the margins of our lease gathered and bulk purchased barrels. We have not included the volumes associated with these buy/sell arrangements.

Gross margin from gathering, marketing, terminalling and storage operations totaled approximately $90.4 million in the year ended December 31, 2002 compared to approximately $71.0 million and $75.9 million in the years ended December 31, 2001 and 2000, respectively. As discussed above, we exclude the impact of SFAS 133 and other unusual or nonrecurring items when evaluating our results. The table below reconciles our reported gross margin for the segment to gross margin before unusual or nonrecurring items and the impact of SFAS 133 ("Adjusted Gross Margin"). Included in the reconciling items below is a $5.0 million noncash writedown of operating crude oil inventory in the fourth quarter of 2001 to reflect prices at December 31, 2001. See Note 2 "Summary of Significant Accounting Policies" in the "Notes to the Consolidated Financial Statements." Additionally, in 2000, we recognized a $7.0 million charge for the settlement of litigation related to the unauthorized trading by a former employee. See Items 1 and 2. "Business and Properties—Unauthorized Trading Losses."

	Year Ended December 31,		
	2002	2001	2000
Reported Gross Margin (in millions)	$ 90.4	$ 71.0	$ 75.9
Noncash mark-to-market inventory charge	—	5.0	—
Unauthorized trading losses and related expenses	—	—	7.0
Noncash reserve for receivables	—	2.0	—
Noncash SFAS 133 adjustment	(0.3)	(0.2)	—
Gross margin before unusual or nonrecurring items and the impact of SFAS 133 (“Adjusted Gross Margin”)	$ 90.1	$ 77.8	$ 82.9

Adjusted Gross Margin increased approximately $12.3 million in the 2002 period as compared to the 2001 period primarily due to higher average daily volumes as discussed above. The decrease in Adjusted Gross Margin in 2001 as compared to the 2000 period is primarily attributable to a relatively weak environment for gathering and marketing due to market conditions. The market conditions during 2000 were favorable for gathering and marketing margins.

G&A includes the costs directly associated with the segment, as well as a portion of corporate overhead costs considered allocable. See “—Other Income and Expenses—Unallocated G&A Expense.” G&A expense related to our gathering, marketing, terminalling and storage operations was $31.5 million for the year ended December 31, 2002 compared to $28.5 million and $25.0 million for the years ended December 31, 2001 and 2000, respectively. The increase in G&A expense of approximately $3.0 million in the 2002 period was primarily due to increased costs of $5.6 million from the assets acquired in the Canadian acquisition due to the inclusion of those assets for the entire 2002 period compared to only a portion of 2001 partially offset by decreased G&A of $2.6 million from our domestic operations. This decrease was partially related to a reduction in accounting and consulting costs in the 2002 period from those that had been incurred in the 2001 period.

G&A expense related to gathering, marketing, terminalling and storage operations increased approximately $3.5 million for the year ended December 31, 2001 from the year ended December 31, 2000. The increase was primarily related to costs of approximately $4.0 million from the assets acquired in the Canadian acquisition and increased personnel costs associated with the General Partner Transition partially offset by lower reserves for potentially uncollectible receivables included in G&A in the 2001 period.

Other Income and Expenses

Unallocated G&A Expenses. Total G&A expenses were $45.7 million, $46.6 million and $40.8 million for the years ended December 31, 2002, 2001 and 2000, respectively. We have included in the above segment discussion the G&A expense for each of these years that were attributable to our segments. During 2002, we incurred charges that were not attributable to a segment of $1.0 million related to the write-off of deferred acquisition-related costs. See “—Outlook—Ongoing Acquisition Activities.” During 2001 and 2000, we incurred charges that were not attributable to a segment of $5.7 million and $3.1 million, respectively, related to incentive compensation paid to certain officers and key employees of Plains Resources and its affiliates. In 1998 (in connection with our IPO) and 2000, Plains Resources granted certain officers and key employees of the former general partner the right to earn ownership in a portion of our common units owned by it. These rights provided for a three-year vesting period, subject to distributions being paid on the common and subordinated units. In connection with the General Partner Transition in 2001, certain equity interests previously granted to management and outside directors vested, resulting in a charge to our 2001 income of approximately $6.1 million, of which Plains Resources funded approximately 94%. Approximately $5.7 million of the 2001 charge and all of the 2000 charge were noncash and were not allocated to a segment.

Depreciation and Amortization. Depreciation and amortization expense was $34.1 million for the year ended December 31, 2002 compared to $24.3 million and $24.5 million for the periods ended December 31, 2001 and 2000, respectively. Excluding depreciation expense of $4.1 million related to the assets acquired in the Shell acquisition, depreciation and amortization expense would have been approximately $30.0 million for the 2002 period. Approximately $3.5 million of the $5.7 million increase in the adjusted depreciation and amortization for the 2002 period is related to the inclusion of the assets acquired in the Canadian acquisition for the entire 2002 period compared to only a portion of 2001. The remainder of the increase is related to an increase in debt issue costs related to the amendment of our credit facilities during 2002 and late 2001, the sale of senior notes in September 2002, and the completion of various capital expansion projects.

Depreciation and amortization expense for the 2000 period includes $4.6 million related to nonrecurring amortization of debt issue costs associated with credit facilities put in place during the fourth quarter of 1999, subsequent to the unauthorized trading losses. Excluding this nonrecurring cost, depreciation and amortization would have been approximately $19.9 million for the 2000 period. The increase of $4.4 million in 2001 from the adjusted 2000 depreciation and amortization expense is primarily related to the assets acquired in the Canadian acquisition.

Interest expense. Interest expense was $29.1 million for the year ended December 31, 2002 compared to $29.1 million and $28.7 million for the years ended December 31, 2001 and 2000, respectively. Interest expense was relatively flat in the 2002 period as compared to the prior year due to the impact of higher debt levels and commitment fees offset by lower average interest rates and the capitalization of interest. The overall increased average debt balance in 2002 is due to the portion of the Shell acquisition in August 2002 which was not refinanced with the issuance of equity. See "—Liquidity and Capital Resources—Liquidity." During the third quarter of 2001, we issued a $200 million senior secured term B loan, the proceeds of which were used to reduce borrowings under the revolver. As such, our commitment fees on our revolver increased as they are based on unused availability. The lower interest rates in 2002 are due to a decrease in LIBOR and prime rates in the current year. In addition, approximately $0.8 million of interest expense was capitalized during 2002, in conjunction with expansion construction on our Cushing terminal compared to approximately $0.2 million in the 2001 period. Interest expense was slightly higher in the 2001 period as compared to the 2000 period primarily due to higher average debt balances, partially offset by lower average interest rates.

Gain on sale of assets. In March 2000, we sold to a unit of El Paso Corporation for $129.0 million the segment of the All American Pipeline that extends from Emidio, California to McCamey, Texas. Except for minor third party volumes, one of our subsidiaries, Plains Marketing, L.P., had been the sole shipper on this segment of the pipeline since its predecessor acquired the line from the Goodyear Tire & Rubber Company in July 1998. We realized net proceeds of approximately $124.0 million after the associated transaction costs and estimated costs to remove equipment. We used the proceeds from the sale to reduce outstanding debt. We recognized a gain of approximately $20.1 million in connection with the sale.

We suspended shipments of crude oil on this segment of the pipeline in November 1999. At that time, we owned approximately 5.2 million barrels of crude oil in the segment of the pipeline. We sold this crude oil from November 1999 to February 2000 for net proceeds of approximately $100.0 million, which were used for working capital purposes. We recognized gains of approximately $28.1 million in 2000 in connection with the sale of the linefill.

Early extinguishment of debt. During 2000, we recognized extraordinary losses, consisting primarily of unamortized debt issue costs, totaling $15.1 million related to the permanent reduction of the All American Pipeline, L.P. term loan facility and the refinancing of our credit facilities. In addition, interest and other income for the year ended December 31, 2000, includes $9.7 million of previously deferred gains from terminated interest rate swaps as a result of debt extinguishment.

Outlook

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of midstream crude oil assets. Such acquisition efforts involve participation by us in processes that have been made public, involve a number of potential buyers and are commonly referred to as "auction" processes, as well as situations where we believe we are the only party or one of a very limited number of potential buyers in negotiations with the potential seller. In connection with these activities, we routinely incur third party costs, which are capitalized and deferred pending final outcome of the transaction. Deferred costs associated with successful transactions are capitalized as part of the transaction, while deferred costs associated with unsuccessful transactions are expensed at the time of such final determination. We can give you no assurance that our current or future acquisitions efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

We were very active in 2002 in evaluating several potential acquisitions and an unusually high level of internal and external resources were devoted to that effort. We were unsuccessful in our pursuit of several sizable acquisition opportunities that were evaluated on an auction basis and also one negotiated transaction that had nearly advanced to the execution stage when it was abruptly terminated by the seller. As a result, our fourth quarter results reflect a $1.0 million charge to G&A expenses associated with the third party costs of these unsuccessful transactions. At December 31, 2002, the remaining balance of deferred acquisition-related costs pending final outcome was not material.

Shutdown of Rancho Pipeline System. The Rancho Pipeline System Agreement dated November 1, 1951, pursuant to which the system was constructed and operated, terminates in March 2003. Upon termination, the agreement requires the owners to take the pipeline system, in which we own an approximate 50% interest, out of service. Accordingly, we have notified our shippers that we will not accept nominations for movements after February 28, 2003. As contemplated at the time of the Shell acquisition, plans are currently under way to purge and idle portions of the pipeline system subject to final determination of the disposition of the system. During 2001, total volumes shipped from West Texas to the Gulf Coast Ship Channel on the Rancho System approximated 83,000 barrels per day. Since acquiring the pipeline in 2002, these volumes averaged approximately 91,000 barrels per day. We estimate that the shut-down of Rancho initially will have a negative influence on operating results in the first and second quarters of 2003 as we take the line out of service and deal with logistical issues. Once the pipeline is shut down, these volumes become candidates for shipment on the Basin system, which we operate and in which we own an approximate 87% interest. We estimate that increased movements on the Basin system will substantially offset the adverse impact on our operating results.

FERC Notice of Proposed Rulemaking. On August 1, 2002, the Federal Energy Regulatory Commission ("FERC") issued a Notice of Proposed Rulemaking that, if adopted, would amend its Uniform Systems of Accounts for oil pipeline companies with respect to participation of a FERC-Regulated subsidiary in the cash management arrangement of its non-FERC-regulated parent. Although it appears that, if adopted, the rule may affect the way in which we manage cash, we believe that the incremental costs will not be significant.

Sarbanes-Oxley Act and New SEC Rules. Several regulatory and legislative initiatives were introduced in 2002 in response to developments during 2001 and 2002 regarding accounting issues at large public companies, resulting disruptions in the capital markets and ensuing calls for action to prevent repetition of those events. We support the actions called for under these initiatives and believe these steps will ultimately be successful in accomplishing the stated objectives. However, implementation of reforms in connection with these initiatives will add to the costs of doing business for all publicly-traded entities, including the Partnership. These costs will have an adverse impact on future income and cash flow, especially in the near term as legal, financial and consultant costs are incurred to analyze the new requirements, formalize current practices and implement required changes to ensure that we maintain compliance with these new rules. We are not able to estimate the magnitude of increase in our costs that will result from such reforms.

Vesting of Unit Grants under LTIP and Conversion of Subordinated Units. In connection with our public offering in 1998, our general partner established a long-term incentive plan, which permits the grant of restricted units and unit options covering an aggregate of approximately 1.4 million units. Grants of approximately 1.0 million restricted units (and no unit options) are outstanding under the plan. A restricted unit grant entitles the grantee to receive a common unit upon the vesting of the restricted unit. Subject to additional vesting requirements, restricted units may vest in the same proportion as the conversion of our outstanding subordinated units into common units. Certain of the restricted unit grants contain additional vesting requirements tied to the Partnership achieving targeted distribution thresholds, generally $2.10, $2.30 and $2.50 per unit, in equal proportions.

Under generally accepted accounting principles, we are required to recognize an expense when the financial tests for conversion of subordinated units and required distribution levels are met. The financial tests involve GAAP accounting concepts as well as complex and esoteric cash receipts and disbursement concepts that are indexed to the minimum quarterly distribution rate of $1.80 per limited partner unit. Because of this complexity, it is difficult to forecast when the vesting of these restricted units will occur. However, at the current annualized distribution level of $2.15 per unit, assuming the subordination conversion test is met, the costs associated with the vesting of up to approximately 845,000 units would be incurred or accrued in the second half of 2003 or the first quarter of 2004. At an annualized distribution level of $2.30 to $2.49, the number of units would be approximately 935,000. At an annualized distribution level at or above $2.50, the number of units would be approximately 1,025,000. We are currently planning to issue units to satisfy the first 975,000 vested and delivered (after any units withheld for taxes) and to purchase units in the open market to satisfy any vesting obligations in excess of that amount. Issuance of units would result in a non-cash compensation expense, while a purchase of units would result in a cash charge to compensation expense. In addition, the “company match” portion of payroll taxes, plus the value of any units withheld for taxes, would result in a cash charge. The amount of the charge to expense will depend on the unit price on the date vesting occurs.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2002, we had a working capital deficit of approximately $34.3 million, approximately $436.9 million of availability under our revolving credit facility and $49.8 million of availability under the letter of credit and hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. In the past, we have generally maintained a positive working capital position. During 2002, we reduced our working capital, primarily through the (i) collection of accounts receivable and certain prepayments and the application of those proceeds to reduce long-term borrowings, and (ii) shifting a portion of our borrowings to finance certain contango inventory and LPG purchase requirements from long-term revolving credit facilities to our hedged inventory and letter of credit facility. The hedged inventory and letter of credit facility requires reduction in outstanding amounts at the time proceeds from the sale of the inventory are collected. Accordingly, amounts drawn under this facility are reflected as a current liability for hedged inventory expected to be sold within one year. In addition, approximately $3.1 million of the company’s net liability under SFAS 133 is reflected as current. With respect to collections referred to in (i) above, during 2002, we collected a net amount of approximately $9.1 million of amounts that had been outstanding primarily since 1999 and 2000. In addition, as of December 31, 2002, to reduce credit risk, we had received approximately $21.5 million of payments related to December 2002 business. Typically, accounts receivable are collected within thirty days following the month of business. See “—Contingencies—Recent Disruptions in Industry Credit Markets.”

We funded the purchase of the Shell acquisition on August 1, 2002, with funds drawn on our revolving credit facilities. Later in August, we completed a public offering of 6,325,000 common units priced at $23.50 per unit. Net proceeds from the offering, including our general partner’s proportionate capital contribution and expenses associated with the offering, were approximately $145.0 million and were used to pay down our revolving credit facilities. During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012, which generated net proceeds of $196.3 million that we used to pay down our revolving credit facilities. See “—Credit Facilities and Long-Term Debt.”

We believe that we have sufficient liquid assets, cash from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce a corollary adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the years ended December 31, 2002, 2001 and 2000 were as follows:

	Year Ended December 31,		
	2002	**2001**	**2000**
		(in millions)	
Cash provided by (used in):			
Operating activities	$ 173.9	$ (30.0)	$ (33.5)
Investing activities	(363.8)	(249.5)	211.0
Financing activities	189.5	279.5	(227.8)

Operating Activities. Net cash provided by operating activities for the year ended December 31, 2002 was $173.9 million as compared to cash used in operating activities of $30.0 million and $33.5 million for the years ended December 31, 2001 and 2000, respectively. Approximately $21.1 million of the increase is due to an increase in net income, predominantly related to our acquisitions completed in April and July 2001 and August 2002. The remainder of the increase is due to changes in working capital items related to the following: (i) the collection of amounts related to prior year balances as discussed above in "—Liquidity" and further below in "—Contingencies—Recent Disruptions in Industry Credit Markets"; (ii) the collection of prepayments due to the increase in credit risk associated with certain counter-parties; and (iii) the sale of hedged crude oil inventory purchased in 2001 and 2002 and the correlated changes in accounts receivable and accounts payable. In addition to the hedged inventory transactions having a positive effect on cash provided by operating activities for the year ended December 31, 2002, similar transactions had a negative effect on the year ended December 31, 2001 as the inventory was being purchased and stored, thus resulting in an even larger variance when comparing the two periods.

Net cash used in operating activities in 2001 is primarily attributable to inventory purchased and stored in our facilities for sale and delivery at a later date. Excluding these inventory purchases, cash provided by operating activities was approximately $88.0 million in 2001. Except for minor amounts, the inventory has been hedged against future price risk by using NYMEX transactions and fixed price sales contracts. Net cash used in operating activities in 2000 resulted primarily from the unauthorized trading losses. The losses were partially offset by increased margins due to the Scurlock and West Texas Gathering System acquisitions.

Investing Activities. Net cash used in investing activities in 2002 includes the payment of $311.4 million related to the Shell acquisition and related transaction costs, $7.1 million for the Butte acquisition and $5.4 million for the Cornerstone acquisition. Investing activities also includes $40.6 million of capital expenditures related to the Cushing expansion, the construction of the Marshall terminal in Canada and other capital projects.

Net cash used in investing activities in 2001 included $229.2 million for the Canadian acquisitions and $21.1 million primarily for other expansion and acquisition projects. Net cash provided by investing activities for 2000 included approximately $224.0 million of proceeds from the sale of the All American Pipeline and pipeline linefill offset by approximately $12.6 million of capital expenditures. Capital expenditures for 2000 included approximately $10.8 million for expansion capital and $1.8 million for maintenance capital.

Financing Activities. Cash provided by financing activities in 2002 consisted of approximately $344.6 million of net proceeds from the issuance of common units and senior unsecured notes, used primarily to fund capital projects and acquisitions and pay down outstanding balances on the revolving credit facility. Net repayments of our short-term and long-term revolving credit facilities during 2002 were $49.9 million. In addition, $99.8 million of distributions were paid to unitholders and the general partner during the year ended December 31, 2002.

Cash provided by financing activities in 2001 consisted primarily of net short-term and long-term borrowings of $134.3 million, proceeds from the issuance of common units of $227.5 million, the payment of $75.9 million in distributions to unitholders and the payment of $6.4 million in financing costs. Cash used in financing activities in 2000 consisted primarily of net short-term and long-term payments of $47.5 million, the repayment of subordinated debt of $114.0 million to our former general partner and distributions to unitholders of $59.6 million. Cash used to reduce the debt primarily came from the asset sales discussed above. Cash used to repay the $114.0 million of subordinated debt to our former general partner came from our revolving credit facility, which was refinanced in May 2000.

Universal Shelf

We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $700 million of debt or equity securities. At December 31, 2002, we have approximately $421 million of remaining availability under this registration statement.

Credit Facilities and Long-term Debt

During September 2002, we completed the sale of $200 million of 7.75% senior notes due in October 2012. The notes were issued by us and a 100% owned 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.

During 2002, we amended our credit facilities to remove a condition requiring us to obtain lender approval before making any acquisition greater than $50.0 million and to accommodate the increased activity level associated with the expanded asset base, while preserving our ability to pursue additional acquisitions.

As amended during 2002 and giving effect to the third quarter capital raising activities, our credit facilities consist of a $350.0 million senior secured letter of credit and hedged inventory facility (with current lender commitments totaling $200.0 million), and a $747.0 million senior secured revolving credit and term loan facility, each of which is secured by substantially all of our assets. The terms of our credit facilities enable us to expand the commitments under the letter of credit and hedged inventory facility from $200.0 million to $350.0 million without additional approval from existing lenders. The revolving credit and term loan facility consists of a $420.0 million domestic revolving facility (with a $10.0 million letter of credit sublimit), a $30.0 million Canadian revolving facility (with a $5.0 million letter of credit sublimit), a $99.0 million term loan, and a $198.0 million term B loan.

The facilities have final maturities as follows:

- as to the $350.0 million senior secured letter of credit and hedged inventory facility and the aggregate $450.0 million domestic and Canadian revolver portions, in April 2005;
- as to the $99.0 million term loan, in May 2006; and

- as to the $198.0 million term B loan, in September 2007.

Our credit facilities 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;
- grant liens;
- sell assets;
- make investments;
- engage in transactions with affiliates;
- enter into prohibited contracts; and
- 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 current ratio (as defined) of at least 1.0 to 1.0;
- a debt coverage ratio which will not be greater than: 5.25 to 1.0 on all outstanding debt and 4.0 to 1.0 on secured debt;
- an interest coverage ratio that is not less than 2.75 to 1.0; and
- a debt to capital ratio of not greater than 0.7 to 1.0 through March 30, 2003, and 0.65 to 1.0 at any time thereafter.

For covenant compliance purposes, letters of credit and borrowings under the letter of credit and hedged inventory facility are excluded when calculating the debt coverage and debt to capital ratios. Additionally, under the covenants, unborrowed availability under the $450 million domestic and Canadian revolving credit facilities is added to working capital to calculate the current ratio for compliance purposes. At December 31, 2002, unborrowed availability was approximately $436.9 for purposes of calculating the current ratio.

A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt and to foreclose on the assets securing the credit facilities. 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 currently in compliance with the covenants contained in our credit facilities and 7.75% senior notes credit agreements.

The amended facility permits us to issue up to an aggregate of $400.0 million of senior unsecured debt that has a maturity date extending beyond the maturity date of the existing credit facility, and provides a mechanism to reduce the amount of the domestic revolving credit facility. The foregoing description of the credit facility incorporates the reduction associated with the $200 million senior note offering completed in September 2002. Depending on the amount of additional senior indebtedness incurred, the domestic revolving credit facility will be reduced by an amount equating to 40% to 63% of any incremental indebtedness up to the aggregate $400 million limitation.

The average life of our debt capitalization at December 31, 2002, was approximately 6.3 years. At the end of the year we had approximately $13.1 million outstanding under our $450 million of revolving credit facilities that mature in 2005, approximately $297 million of senior secured term loans with final maturity dates in 2006 and 2007 and $200 million of senior notes which mature in 2012. We have classified the $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.

Term loan payments are as follows (in millions):

Calendar Year	Payment
2003	$ 9.0
2004	10.0
2005	10.0
2006	78.0
2007	190.0
Total	$ 297.0

We manage our exposure to increasing interest rates. Based on December 31, 2002, debt balances, floating rate indexes at the end of January 2003, our credit spread under our credit facilities and the combination of our fixed rate debt and current interest rate hedges, the average interest rate was approximately 6.1%, excluding non-use and facilities fees, which will vary based on usage and outstanding balance. Based on current amounts outstanding, we estimate these fees will average approximately $2.2 million per year. We have locked-in interest rates (excluding the credit spread under the credit facilities) for approximately 60% of our total debt for the next year, 50% for the next four years and 40% for the next ten years.

Contingencies

Recent Disruptions in Industry Credit Markets. As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries during 2001 and 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 troubling disclosures by several large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large, energy-related companies. Accordingly, in this environment 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 many cases involving complex exchanges of crude oil volumes. In transacting business with our counterparties, we must determine the amount, if any, of open credit lines to extend to our counterparties and the form and amount of financial performance assurances we may require. As a result of these developments, during 2002 we modified our ongoing credit arrangements with certain counterparties, reducing or eliminating the amount of open credit we extend and requiring prepayments or standby letters of credit for business activities that exceed these revised credit limits.

The vast majority of our accounts receivable settle monthly and any collection delays generally involve discrepancies or disputes as to the appropriate price, volume or quality of crude oil delivered or exchanged and associated billing delays. At December 31, 2002, approximately 99% of our net accounts receivables included in current assets are less than 60 days past scheduled invoice date. The majority of the remaining 1% and the balance of accounts receivable classified as long-term relate to monthly periods leading up to and immediately following the disclosure of unauthorized trading losses that we experienced in late 1999. Such balances are subject to ongoing reconciliations primarily to resolve discrepancies associated with pricing, volumes, quality or crude oil exchange imbalances. Following the unauthorized trading loss disclosure, a significant number of our suppliers and trading partners temporarily reduced or eliminated our open credit and demanded payments or withheld payments due us before disputed amounts or discrepancies were reconciled in accordance with customary industry practices. Because these matters also arose in the midst of various software systems conversions and acquisition integration activities, our effort to resolve outstanding claims and discrepancies has included reprocessing and integrating historical information on numerous software platforms. During 2002, significant, concerted effort was directed to resolving these matters in an ongoing effort to bring substantially all receivable balances to within sixty days of scheduled invoice date. As a result of this effort, the aggregate balance of all account receivable balances greater than sixty days past scheduled invoice date at December 31, 2001 was reduced by approximately 64% and the balance of our accounts receivable included in current assets that were less than 60 days past scheduled invoice date improved to 99% at December 31, 2002 from 93% at December 31, 2001. Based on the work performed to date, we believe net receivable balances greater than sixty days past scheduled invoice date are collectible or subject to offsets and consider our reserves adequate. However, in the event our counterparties experience an unanticipated deterioration in their credit-worthiness, any addition to existing reserves or write-offs in excess of such reserves would result in a noncash charge to earnings. We do not believe any such charge would have a material effect on our cash flow or liquidity.

To date, these market disruptions have not had a material adverse impact on our activities or on obtaining open credit for our account with counterparties. In February 2003 Standard and Poor's upgraded our corporate credit rating to investment grade, assigning us a rating of BBB-, stable outlook. In September 2002, Moody's Investor Services upgraded our senior implied credit rating to Ba1, stable outlook. You should note that a credit rating is not a recommendation to buy, sell, or hold securities, and may be subject to revision or withdrawal at any time.

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. 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 these potential violations.

Pipeline and Storage Regulation. We are subject to the U.S. Department of Transportation's (the "DOT's") pipeline integrity rules, which require continual assessment of pipeline segments that could affect "high consequence areas." Our compliance costs will vary from year to year based on the assessment priority placed on particular line segments. Based on currently available information, we estimate that such costs will average approximately $1.9 million per year in 2003 and 2004. Such amounts incorporate approximately $1 million per year associated with assets acquired in the Shell acquisition. We will continue to refine our estimates as data from initial assessments is collected. See Items 1 and 2. "—Business and Properties—Regulation—Pipeline and Storage Regulation."

The DOT has adopted API 653 as the standard for the inspection, repair, alteration and reconstruction of existing crude oil storage tanks subject to DOT jurisdiction (approximately 61% of our 22.7 million barrels). API 653 requires regularly scheduled inspection and repair of tanks remaining in service. Full compliance is required by 2009. We have commenced our compliance activities under the standard and, based on currently available information, we estimate that we will spend approximately $1.0 million per year in 2003 and 2004 in connection with these activities. Such amounts incorporate costs associated with assets acquired in the Shell acquisition. We will continue to refine our estimates as data from initial assessments is collected.

Other. A pipeline, terminal or other facilities may experience damage as a result of an accident or natural disaster. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers all of our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. Consistent with insurance coverage generally available to the industry, our insurance policies provide limited coverage for losses or liabilities relating to pollution, with broader coverage for sudden and accidental occurrences. The events of September 11, 2001, and their overall effect on the insurance industry has had an adverse impact on availability and cost of coverage. Due to these events, insurers have excluded acts of terrorism and sabotage from our insurance policies. On certain of our key assets, we purchased a separate insurance policy for acts of terrorism and sabotage.

Since the terrorist attacks, the United States Government has issued numerous warnings that energy assets (including our nation's pipeline infrastructure) may be future targets of terrorist organizations. These developments expose our operations and assets to increased risks. The DOT has developed a security guidance document and has issued a security circular that defines critical pipeline facilities and appropriate countermeasures for protecting them, and explains how DOT plans to verify that operators have taken appropriate action to implement satisfactory security procedures and plans. Using the guidelines provided by the DOT, we have specifically identified certain of our facilities as DOT "critical facilities" and therefore potential terrorist targets. In compliance with DOT guidance, we are performing vulnerability analyses on such facilities. Upon completion of such analyses, we will institute as appropriate any indicated security measures or procedures that are not already in place. We cannot assure you that these or any other security measures would protect our facilities from a concentrated attack. Any future terrorist attacks on our facilities, those of our customers and, in some cases, those of our competitors, could have a material adverse effect on our business whether insured or not.

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.

Capital Requirements

We have made and will continue to make capital expenditures for acquisitions and expansion and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations, credit facility borrowings, the issuance of senior unsecured notes and the sale of additional common units.

We expect to spend approximately $83.0 million on expansion capital projects during 2003. This includes approximately $50.0 million for one acquisition that we closed in the first quarter of 2003 and two additional acquisitions currently being negotiated which, if consummated, are expected to close in March or April of 2003. The assets acquired in the transaction that closed in the first quarter consist of a 347-mile crude oil pipeline system and approximately 695,000 barrels of crude oil storage capacity. We plan to replace approximately 32 miles of existing pipe on this pipeline and to build a twelve-mile extension of the system to connect to our terminal in Cushing. Approximately $8 million of costs related to this acquisition will not be incurred until 2004.

Our expansion capital estimate also includes costs for various internal expansion projects and approximately $18.1 million to construct crude oil gathering and transmission lines in West Texas. We also estimate we will spend approximately $8.5 million in maintenance capital during 2003. In addition, we anticipate increasing our share of the crude oil linefill in the Basin Pipeline throughout 2003, potentially adding as much as one million barrels as we expand our shipment activities on this pipeline. The cost to purchase this linefill will depend on market conditions at the time of purchase.

Commitments

The following table reflects our long-term non-cancelable contractual obligations as of December 31, 2002 (in millions):

Contractual Obligations	2003	2004	2005	2006	2007	Thereafter	Total
Long-term debt (including current maturities)	$ 9.0	$10.0	$23.1	$78.0	$190.0	$ 200.0	$510.1
Operating leases	9.4	9.6	9.4	7.0	2.7	0.5	38.6
Total contractual cash obligations	$18.4	$19.6	$32.5	$85.0	$192.7	$ 200.5	$548.7

Operating leases are primarily for office rent and trucks used in our gathering activities. Other than the amounts reflected above for operating leases, we have no other financing arrangements that are not reflected on the consolidated balance sheet. As is common within the industry, we have entered into various operational commitments and agreements related to pipeline operations and to the marketing, transportation, terminalling and storage of crude oil. We believe that such commitments will be met without a material adverse effect on our financial position, results of operations or cash flows.

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 cash and cash equivalents on hand at the end of the quarter less reserves established by our general partner for future requirements. Minimum quarterly distributions are $0.45 per unit for each full fiscal quarter. Distributions of available cash to the holders of subordinated units are subject to the prior rights of the holders of common units to receive the minimum quarterly distributions for each quarter during the subordination period, and to receive any arrearages in the distribution of minimum quarterly distributions on the common units for prior quarters during the subordination period. There were no arrearages on common units at December 31, 2002. On February 14, 2003, we paid a cash distribution of $0.5375 per unit on all outstanding units. The total distribution paid was approximately $28.2 million, with approximately $21.2 million paid to our common unitholders, $5.4 million paid to our subordinated unitholders and $1.6 million paid to our general partner for its general partner ($0.6 million) and incentive distribution interests ($1.0 million).

Our general partner is entitled to 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, our general partner is entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per limited partner unit, 25% of amounts we distribute in excess of $0.495 per limited partner unit and 50% of amounts we distribute in excess of $0.675 per limited partner unit. See Item 13. “Certain Relationships and Related Transactions—Our General Partner.”

In connection with our crude oil marketing, we provide certain purchasers 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, 2002, we had outstanding letters of credit of approximately $52.5 million. These letters of credit are secured by our crude oil inventory and accounts receivable.

Related Party Transactions

We have a long-term agreement with Plains Resources (including its subsidiaries that conduct exploration and production activities) pursuant to which we purchase for resale at market prices all of Plains Resources’ equity crude oil production for a fee of $0.20 per barrel. In November 2001, the agreement automatically extended for three years. The fee is subject to adjustment every three years based on then-existing market conditions. For the years ended December 31, 2002, 2001 and 2000, we paid approximately $247.7 million, $223.2 million and $244.9 million, respectively for Plains Resources’ production and recognized gross margin of approximately $1.8 million, $1.8 million and $1.7 million. On December 18, 2002, Plains Resources completed a spin-off of one of its subsidiaries, Plains Exploration and Production ("PXP"), to its shareholders. PXP is a successor participant to this marketing agreement.

Recent Accounting Pronouncements

In December 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 148 "Accounting for Stock-Based Compensation—Transition and Disclosure." SFAS 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS 148 amends the disclosure requirements of SFAS 123 in both annual and interim financial statements. SFAS 148 is effective for financial statements for fiscal years ending after December 15, 2002, and financial reports containing condensed financial statements for interim periods beginning after December 15, 2002. Our general partner has stock-based employee compensation plans (see Notes 12 and 13). These plans are accounted for under the "fair value" method as described in SFAS 123. Therefore, we do not believe that the adoption of this statement will have a material effect on either our financial position, results of operations, cash flows or disclosure requirements.

In October 2002, the Emerging Issues Task Force ("EITF") reached consensus on certain issues in EITF Issue No. 02-03, "Recognition and Reporting of Gains and Losses on Energy Trading Contracts under Issues No. 98-10 and 00-17." The consensus reached included (i) rescinding EITF 98-10 and (ii) the requirement that mark-to-market gains and losses on trading contracts (whether realized or unrealized and whether financially or physically settled) be shown net in the income statement using the indicators identified in Issue No. 98-10. The EITF provided guidance that, beginning on October 25, 2002, all new contracts that would have been accounted for under EITF 98-10 should no longer be marked-to-market through earnings unless such contracts fall within the scope of SFAS 133. All of the contracts that we have accounted for under EITF 98-10 fall within the scope of SFAS 133 and therefore will continue to be marked-to-market through earnings under the provisions of that rule. Therefore, the adoption of this rule did not have a material effect on either our financial position, results of operations or cash flows.

In June 2002, the FASB issued SFAS No. 146 "Accounting for Costs Associated with Exit or Disposal Activities." SFAS 146 requires that a liability for a cost associated with an exit or disposal activity be recognized when the obligation is incurred rather than at the date of the exit plan. This Statement is effective for exit or disposal activities that are initiated after December 31, 2002. We have not initiated exit or disposal activities that are subject to this statement and thus do not believe that the adoption of SFAS 146 will have a material effect on either our financial position, results of operations or cash flows.

In April 2002, the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." SFAS 145 rescinds, updates, clarifies and simplifies existing accounting pronouncements. Among other things, SFAS 145 rescinds SFAS 4, which required all gains and losses from extinguishment of debt to be aggregated and, if material, classified as an extraordinary item, net of related income tax effect. Under SFAS 145, the criteria in Accounting Principles Board No. 30 will now be used to classify those gains and losses. The adoption of this and the remaining provisions of SFAS 145 did not have a material effect on our financial position or results of operations. However, any future extinguishments of debt may impact income from continuing operations.

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 removal and/or remediation activities when the asset is retired. 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 determine the settlement dates. The cumulative effect of adopting this statement will not have a material impact on our financial position, results of operations or cash flows.

Risk Factors Related to Our Business

The level of our profitability is dependent upon an adequate supply of crude oil from fields located offshore and onshore California. Production from these offshore fields has experienced substantial production declines since 1995.

A significant portion of our gross margin is derived from pipeline transportation margins associated with the Santa Ynez and Point Arguello fields located offshore California. We expect that there will continue to be natural production declines from each of these fields as the underlying reservoirs are depleted. A 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline tariff revenues of approximately $3.1 million. In addition, any production disruption from these fields due to production problems, transportation problems or other reasons would have a material adverse effect on our business.

Potential future acquisitions and expansions, if any, may affect our business by substantially increasing the level of our indebtedness and contingent liabilities and increasing our risks of being unable to effectively integrate these new operations.

From time to time, we evaluate and acquire assets and businesses that we believe complement our existing assets and businesses. The Shell acquisition represents a significant acquisition for us and, as a result, we may encounter difficulties integrating this acquisition with our existing business and our other recent acquisitions and successfully managing the rapid growth we expect to experience from these acquisitions. Acquisitions may require substantial capital or the incurrence of substantial indebtedness. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you will not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in determining the application of these funds and other resources.

Our crude oil marketing business requires extensive credit risk management that may not be adequate to protect against customer nonpayment.

As a result of business failures, revelations of material misrepresentations and related financial restatements by several large, well-known companies in various industries over the past year, 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 troubling disclosures by several large, diversified energy companies, the energy industry has been especially impacted by these developments, with the rating agencies downgrading a number of large, energy related companies. Accordingly, in this environment we are exposed to an increased level of direct and indirect counter-party credit and performance risk. There can be no assurance that we have adequately assessed the credit worthiness of our existing or future counter-parties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

The profitability of our pipeline operations depends on the volume of crude oil shipped by third parties.

Third party shippers generally do not have long-term contractual commitments to ship crude oil on our pipelines. A decision by a shipper to substantially reduce or cease to ship volumes of crude oil on our pipelines could cause a significant decline in our revenues. For example, an average 25,000 barrel per day variance in the Basin Pipeline System, the primary asset we acquired from Shell, equivalent to an approximate 10% volume variance on that pipeline system, would result in an approximate $3.8 million change in annualized gross margin.

In 1999, we suffered a large loss from unauthorized crude oil trading by a former employee. A loss of this kind could occur again in the future in spite of our best efforts to prevent it.

Generally, it is our policy that as we purchase crude oil, we establish a margin by selling crude oil for physical delivery to third party users, such as independent refiners or major oil companies, or by entering into a future delivery obligation under futures contracts on the NYMEX and over-the-counter. Through these transactions, we seek to maintain a position that is substantially balanced between purchases, on the one hand, and sales or future delivery obligations, on the other hand. Our policy is not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. We discovered in November 1999 that this policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million, including estimated costs and legal expenses. We have taken steps within our organization to enhance our processes and procedures to prevent future unauthorized trading. We cannot assure you, however, that these steps will detect and prevent all violations of our trading policies and procedures, particularly if deception or other intentional misconduct is involved.

The success of our business strategy to increase and optimize throughput on our pipeline and gathering assets is dependent upon our securing additional supplies of crude oil.

Our operating results are dependent upon securing additional supplies of crude oil from increased production by oil companies and aggressive lease gathering efforts. The ability of producers to increase production is dependent on the prevailing market price of oil, the exploration and production budgets of the major and independent oil companies, the depletion rate of existing reservoirs, the success of new wells drilled, environmental concerns, regulatory initiatives and other matters beyond our control. There can be no assurance that production of crude oil will rise to sufficient levels to cause an increase in the throughput on our pipeline and gathering assets.

Our operations are dependent upon demand for crude oil by refiners in the Midwest and on the Gulf Coast. Any decrease in this demand could adversely affect our business.

Demand also depends on the ability and willingness of shippers having access to our transportation assets to satisfy their demand by deliveries through those assets, and any decrease in this demand could adversely affect our business. Demand for crude oil is dependent upon the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce demand.

We face intense competition in our terminalling and storage activities and gathering and marketing activities.

Our competitors include other crude oil pipelines, the major integrated oil companies, their marketing affiliates, and independent gatherers, brokers and marketers of widely varying sizes, financial resources and experience. Some of these competitors have capital resources many times greater than ours and control greater supplies of crude oil.

The profitability of our gathering and marketing activities depends primarily on the volumes of crude oil we purchase and gather.

To maintain the volumes of crude oil we purchase, we must continue to contract for new supplies of crude oil to offset volumes lost because of natural declines in crude oil production from depleting wells or volumes lost to competitors. Replacement of lost volumes of crude oil is particularly difficult in an environment where production is low and competition to gather available production is intense. Generally, because producers experience inconveniences in switching crude oil purchasers, such as delays in receipt of proceeds while awaiting the preparation of new division orders, producers typically do not change purchasers on the basis of minor variations in price. Thus, we may experience difficulty acquiring crude oil at the wellhead in areas where there are existing relationships between producers and other gatherers and purchasers of crude oil. We estimate that a 5,000 barrel per day decrease in barrels gathered by us would have an approximate $900,000 per year negative impact on gross margin. This impact is based on a reasonable margin throughout various market conditions. Actual margins vary based on the location of the crude oil, the strength or weakness of the market and the grade or quality of crude oil.

We are exposed to the credit risk of our customers in the ordinary course of our gathering and marketing activities.

In those cases where we provide division order services for crude oil purchased at the wellhead, we may be responsible for distribution of proceeds to all parties. In other cases, we pay all of or a portion of the production proceeds to an operator who distributes these proceeds to the various interest owners. These arrangements expose us to operator credit risk, and there can be no assurance that we will not experience losses in dealings with other parties.

Our operations are subject to federal and state environmental and safety laws and regulations relating to environmental protection and operational safety.

Our pipeline, gathering, storage and terminalling facilities operations are subject to the risk of incurring substantial environmental and safety related costs and liabilities. These costs and liabilities could arise under increasingly strict environmental and safety laws, including regulations and enforcement policies, or claims for damages to property or persons resulting from our operations. If we were not able to recover such resulting costs through insurance or increased tariffs and revenues, our cash flows and results of operations could be materially impacted.

The transportation and storage of crude oil results in a risk that crude oil and other hydrocarbons may be suddenly or gradually released into the environment, potentially causing substantial expenditures for a response action, significant government penalties, liability to government agencies for natural resources damages, liability to private parties for personal injury or property damages, and significant business interruption.

Our Canadian pipeline assets are subject to federal and provincial regulation.

Our Canadian pipeline assets are subject to regulation by the National Energy Board and by provincial agencies. With respect to a pipeline over which it has jurisdiction, each of these agencies has the power to determine the rates we are allowed to charge for transportation on such pipeline. The extent to which regulatory agencies can override existing transportation contracts has not been fully decided.

Our pipeline systems are dependent upon their interconnections with other crude oil pipelines to reach end markets.

Reduced throughput on these interconnecting pipelines as a result of testing, line repair, reduced operating pressures or other causes could result in reduced throughput on our pipeline systems that would adversely affect our profitability.

Our tax treatment depends on our status as a partnership for federal income tax purposes, as well as our not being subject to entity-level taxation by states. If the IRS treats us as a corporation or we become subject to entity-level taxation for state tax purposes, it would substantially reduce distributions to our unitholders and our ability to make payments on our debt securities.

The after-tax economic benefit of an investment in the common units depends largely on our being treated as a partnership for federal income tax purposes. If we were classified as a corporation for federal income tax purposes, we would pay federal income tax on our income at the corporate rate. Some or all of the distributions made to unitholders would be treated as dividend income, and no income, gains, losses or deductions would flow through to unitholders. Treatment of us as a corporation would cause a material reduction in the anticipated cash flow and after-tax return to the unitholders, likely causing a substantial reduction in the value of the common units. Moreover, treatment of us as a corporation would materially and adversely affect our ability to make payments on our debt securities.

In addition, because of widespread state budget deficits, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise or other forms of taxation. If any state were to impose a tax upon us as an entity, the cash available for distribution to you would be reduced. The partnership agreement provides that, if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for federal, state or local income tax purposes, then the minimum quarterly distribution and the target distribution levels will be decreased to reflect that impact on us.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risks*

We are exposed to various market risks, including volatility in (i) crude oil and LPG commodity prices, (ii) interest rates and (iii) currency exchange rates. We utilize various derivative instruments to manage such exposure. 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 our hedging activities address our market risks. We have a risk management function that has direct responsibility and authority for our risk policies and our trading controls and procedures and certain aspects of corporate risk management. To hedge the risks discussed above we engage in price risk management activities that we categorize by the risks we are hedging. The following discussion addresses each category of risk.

Commodity Price Risk

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 New York Mercantile Exchange and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies (see Note 6 to our consolidated financial statements for a discussion of the mitigation of credit risk). Our policy is to purchase only crude oil for which we have a market, and to structure our sales contracts so that crude oil price fluctuations do not materially affect the gross margin we receive. Except for inventory transactions that generally do not exceed approximately 500,000 barrels, we do not enter into derivative transactions for speculative trading purposes. Similarly, while we seek to maintain a position that is substantially balanced within our LPG activities, as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions, from time to time we experience net unbalanced positions for short periods of time. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, our policies provide that any net imbalance may not exceed 200,000 barrels. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. See Items 1 and 2. “Business and Properties—Crude Oil Volatility; Counter-Cyclical Balance; Risk Management.”

As a result of production and delivery variances associated with our lease purchase activities, from time to time we experience net unbalanced positions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in this controlled trading program for up to 500,000 barrels. This activity is monitored independently by our risk management function and must take place within predefined limits and authorizations. In order to hedge margins involving our physical assets and manage risks associated with our crude oil purchase and sale obligations, we use derivative instruments, including regulated futures and options transactions, as well as over-the-counter instruments. In analyzing our risk management activities, we draw a distinction between enterprise-level risks and trading-related risks. Enterprise-level risks are those that underlie our core businesses and may be managed based on whether there is value in doing so. Conversely, trading-related risks (the risks involved in trading in the hopes of generating an increased return) are not inherent in the core business; rather, those risks arise as a result of engaging in the trading activity. We have a Risk Management Committee that approves all new risk management strategies through a formal process. With the partial exception of the limited 500,000-barrel program, our approved strategies are intended to mitigate enterprise-level risks that are inherent in our core businesses of gathering and marketing and storage.

Although the intent of our risk-management strategies is to hedge our margin, not all of our derivatives qualify for hedge accounting. In such instances, changes in the fair values of these derivatives will receive mark-to-market treatment in current earnings, and result in greater potential for earnings volatility than in the past. This accounting treatment is discussed further under Note 2 “Summary of Significant Accounting Policies” in the “Notes to the Consolidated Financial Statements.”

All of our open commodity price risk derivatives at December 31, 2002 were categorized as non-trading. The fair value of these instruments and the change in fair value that would be expected from a 10 percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 0.6	$ (4.3)
Swaps and options contracts	$ (0.2)	$ 2.0
LPG:		
Futures contracts	$ —	$ —
Swaps and options contracts	$ (0.4)	$ 0.2

The fair values of the futures contracts are based on quoted market prices obtained from the NYMEX. The fair value of the swaps and option contracts are estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. These quotes are compared to the contract price of the swap, which approximates the gain or loss that would have been realized if the contracts had been closed out at year end. 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. The assumptions in these estimates as well as the source is maintained by the independent risk control function. All hedge positions offset physical positions exposed to the cash market; none of these offsetting physical positions are included in the above table. Price-risk sensitivities were calculated by assuming an across-the-board 10 percent decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10 percent change in prompt month crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

Interest Rate Risk

We utilize both fixed and variable rate debt, and are exposed to market risk due to the floating interest rates on our credit facilities and our term loans. Therefore, we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. The table below presents principal payments and the related weighted average interest rates by expected maturity dates for variable rate debt outstanding at December 31, 2002. The 7.75% senior notes issued during 2002 are fixed rate notes and thus are not subject to market risk. Our variable rate debt bears interest at LIBOR or prime plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2002. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates (dollars in millions).

	Expected Year of Maturity						
	2003	2004	2005	2006	2007	Thereafter	Total
Liabilities:							
Short-term debt (and current maturities of long-term debt)—variable rate	$99.2	$ —	$ —	$ —	$ —	$ —	$ 99.2
Average interest rate	3.4%	—	—	—	—	—	3.4%
Long-term debt—variable rate	$ 9.0	$10.0	$23.1	$78.0	$190.0	$ —	$310.1
Average interest rate	3.9%	3.9%	4.4%	3.9%	3.9%	0.0%	3.9%

Interest rate swaps, collars and treasury locks are used to hedge underlying interest payment obligations. We estimate the fair value of these instruments based on current termination values. These instruments hedge interest rates on specific debt issuances and qualify for hedge accounting. The interest rate differential is reflected as an adjustment to interest expense over the life of the instruments.

The table shown below summarizes the fair value of our interest rate swaps and treasury lock by the year of maturity (in millions):

	Year of Maturity				
	2003	2004	2005	2006	Total
Interest rate swaps	$ —	$ (1.7)	$ —	$ (4.6)	$ (6.3)
Treasury lock	(3.3)	—	—	—	(3.3)
Total	$ (3.3)	$ (1.7)	$ —	$ (4.6)	$ (9.6)

The instruments outstanding at December 31, 2002, consist of interest rate swaps and a treasury lock with an aggregate notional principal amount of $150 million. The interest rate swaps are based on LIBOR rates and provide 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 being hedged is 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 has a notional principal amount of $50 million and an effective interest rate of 4.60% and matures in January, 2003. In January, 2003, the treasury lock maturity was extended to March, 2003 with an effective interest rate of 4.68%.

Currency Exchange Risk

Our cash flow stream relating to our Canadian operations is based on the U.S. dollar equivalent of such amounts measured in Canadian dollars. Assets and liabilities of our Canadian subsidiaries are translated to U.S. dollars using the applicable exchange rate as of the end of a reporting period. Revenues, expenses and cash flow are translated using the average exchange rate during the reporting period.

Since substantially all of our Canadian business is conducted in Canadian dollars, we use certain financial instruments to minimize the risks of changes in the exchange rate. These instruments include forward exchange contracts, forward extra option contracts and cross currency swaps. Additionally, at December 31, 2002, $2.7 million ($4.3 million Canadian based on a Canadian-U.S. dollar exchange rate of 1.58) of our long-term debt was denominated in Canadian dollars. All of the financial instruments utilized are placed with large creditworthy financial institutions.

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-U.S. dollar exchange rate of 1.54). 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 senior secured term loan (25% of the total) from U.S. dollars to $38.3 million of Canadian dollar debt (based on a Canadian-U.S. dollar exchange rate of 1.55). The terms of this contract mirror the term loan, matching the amortization schedule and final maturity in May 2006.

We estimate the fair value of these instruments based on current termination values. The table shown below summarizes the fair value of our foreign currency hedges by year of maturity (in millions):

	Year of Maturity				
	2003	**2004**	**2005**	**2006**	**Total**
Forward exchange contracts	$ 0.1	$ —	$ —	$ —	$ 0.1
Forward extra options	0.2	—	—	—	0.2
Cross currency swaps	—	—	—	0.3	0.3
Total	$ 0.3	$ —	$ —	$ 0.3	$ 0.6

Item 8. ***Financial Statements and Supplementary Data***

The information required here is included in the report as set forth in the “Index to Financial Statements” on page F-1.

Item 9. ***Changes In and Disagreements With Accountants on Accounting and Financial Disclosure***

None.