PART II

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

The common units are listed and traded on the New York Stock Exchange under the symbol "PAA". On February 24, 2005, the closing market price for the common units was $39.22 per unit and there were approximately 32,000 record holders and beneficial owners (held in street name). As of February 24, 2005, there were 67,293,108 common units outstanding. The number of common units outstanding on this date includes the 3,245,700 Class C common units and the 1,307,190 Class B common units that converted in February 2005.

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		Cash
	High	Low	Distributions(1)
2003			
1st Quarter	$26.90	$24.20	$0.5500
2nd Quarter	31.48	24.65	0.5500
3rd Quarter	32.49	29.10	0.5500
4th Quarter	32.82	29.76	0.5625
2004			
1st Quarter	$35.23	$31.18	$0.5625
2nd Quarter	36.13	27.25	0.5775
3rd Quarter	35.98	31.63	0.6000
4th Quarter	37.99	34.51	0.6125

(1) Cash distributions are paid in the following calendar quarter.

Cash Distribution Policy

We will distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below.

Definition of Available Cash. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the end of that quarter less the amount of cash reserves that are necessary or appropriate in the reasonable discretion of the general partner to:

- provide for the proper conduct of our business;
- comply with applicable law or any partnership debt instrument or other agreement; or
- provide funds for distributions to unitholders and the general partner in respect of any one or more of the next four quarters.

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, 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. We paid $8.3 million to the general partner in incentive distributions in 2004. Our most recent quarterly distribution was $0.6125 per unit. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

Under the terms of the agreements governing our debt, 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."

Item 6. *Selected Financial and Operating Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2004, 2003, 2002, 2001 and 2000 and for the years then ended. The selected financial data should be read in conjunction with the consolidated financial statements, including the notes thereto, and Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations."

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(in millions except per unit data)				
Statement of operations data:					
Revenues[10]	$20,975.5	$12,589.8	$8,384.2	$6,868.2	$6,641.2
Cost of sales and field operations (excluding LTIP charge)[10]	(20,641.1)	(12,366.6)	(8,209.9)	(6,720.9)	(6,506.5)
Unauthorized trading losses and related expenses	—	—	—	—	(7.0)
Inventory valuation adjustment	(2.0)	—	—	(5.0)	—
LTIP charge—operations[1]	(0.9)	(5.7)	—	—	—
General and administrative expenses (excluding LTIP charge)	(75.8)	(50.0)	(45.7)	(46.6)	(40.8)
LTIP charge—general and administrative[1]	(7.0)	(23.1)	—	—	—
Depreciation and amortization	(67.2)	(46.8)	(34.0)	(24.3)	(24.5)
Total costs and expenses	(20,794.0)	(12,492.3)	(8,289.6)	(6,796.8)	(6,578.8)
Gain on sale of assets	0.6	0.6	—	1.0	48.2
Asset impairment	(2.0)	—	—	—	—
Operating income	180.1	98.2	94.6	72.4	110.6
Interest expense	(46.7)	(35.2)	(29.1)	(29.1)	(28.7)
Interest and other income (expense), net[2]	(0.3)	(3.6)	(0.2)	0.4	(4.4)
Income from continuing operations before cumulative effect of change in accounting principle[2][3]	$133.1	$59.4	$65.3	$43.7	$77.5
Basic net income per limited partner unit before cumulative effect of change in accounting principle[2][3]	$1.94	$1.01	$1.34	$1.12	$2.13
Diluted net income per limited partner unit before cumulative effect of change in accounting principle[2][3]	$1.94	$1.00	$1.34	$1.12	$2.13
Basic weighted average number of limited partner units outstanding	63.3	52.7	45.5	37.5	34.4
Diluted weighted average number of limited partner units outstanding	63.3	53.4	45.5	37.5	34.4
Balance sheet data (at end of period):					
Total assets	$3,160.4	$2,095.6	$1,666.6	$1,261.2	$885.8
Total long-term debt[4]	949.0	519.0	509.7	354.7	320.0
Total debt	1,124.5	646.3	609.0	456.2	321.3
Partners' capital	1,070.2	746.7	511.6	402.8	214.0

	Year Ended December 31,				
	2004	2003	2002	2001	2000
	(in millions except per unit and volume data)				
Other data:					
Maintenance capital expenditures	$11.3	$7.6	$6.0	$3.4	$1.8
Net cash provided by (used in) operating activities[5]	104.0	115.3	185.0	(16.2)	(33.5)
Net cash provided by (used in) investing activities[5]	(651.2)	(272.1)	(374.9)	(263.2)	211.0
Net cash provided by (used in) financing activities	554.5	157.2	189.5	279.5	(227.8)
Declared distributions per limited partner unit[6][7][8]	2.30	2.19	2.11	1.95	1.83
Operating Data:					
Volumes (thousands of barrels per day)[9]					
Pipeline segment:					
Tariff activities					
All American	54	59	65	69	74
Link acquisition	283	N/A	N/A	N/A	N/A
Capline	123	N/A	N/A	N/A	N/A
Basin	265	263	93	N/A	N/A
Other domestic	424	299	219	144	130
Canada	263	203	187	132	N/A
Pipeline margin activities	74	78	73	61	60
Total	1,486	902	637	406	264
Gathering, marketing, terminalling and storage segment:					
Crude oil lease gathering	589	437	410	348	262
Crude oil bulk purchases	148	90	68	46	28
Total	737	527	478	394	290
LPG sales	48	38	35	19	N/A

(1) Compensation expense related to our 1998 Long Term Incentive Plan ("1998 LTIP"), see "Executive Compensation—1998 Long Term Incentive Plan—Phantom Units."

(2) The 2000 period includes $15.1 million related to losses on the early extinguishment of debt previously classified as an extraordinary item. Effective with our adoption of Statement of Financial Accounting Standards ("SFAS") 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections" in January 2003, such items are now shown as impacting income from continuing operations. As a result of this reclassification, basic and diluted net income per limited partner unit before cumulative effect of change in accounting principle for 2000 was reduced by $0.44. In addition, effective with the issuance of the Emerging Issues Task Force Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two Class Method under FASB Statement No. 128," the 2000 amount was further reduced by $0.07.

(3) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of our January 1, 2004 change in our method of accounting for pipeline linefill in third party assets would have been $61.4 million, $64.8 million, $38.4 million and $78.2 million for each of the four years ended December 31, 2003, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $1.05 ($1.04 diluted), $1.33 ($1.33 diluted), $0.97 ($0.97 diluted) and $2.15 ($2.15 diluted) for each of the four years ended December 31, 2003, respectively.

(4) Includes current maturities of long-term debt of $9.0 million and $3.0 million at December 31, 2002 and 2001, respectively, classified as long-term because of our ability and intent to refinance these amounts under our long-term revolving credit facilities.

(5) In conjunction with the change in accounting principle we adopted as of January 1, 2004, we have reclassified cash flows for the years 2003 and prior associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification as cash flows from operating activities.

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

(7) No distributions were declared or paid on subordinated units in the first quarter of 2000. A distribution of $0.45 per unit was declared and paid to holders of common units in that period.

(8) Our general partner is entitled to receive 2% proportional distributions and also incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. See Note 6 "Partners' Capital and Distributions" in the "Notes to the Consolidated Financial Statements."

(9) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

(10) Includes buy/sell transactions, see Note 2 "Summary of Significant Accounting Policies" in the "Notes to the Consolidated Financial Statements."

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions
- Critical Accounting Policies and Estimates
- Recent Accounting Pronouncements and Change in Accounting Principle
- Results of Operations
- Outlook
- Liquidity and Capital Resources
- Off-Balance Sheet Arrangements
- Risk Factors Related to Our Business

Executive Summary

Company Overview

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in September of 1998. Our operations are conducted directly and indirectly through our operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P. We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other petroleum products. We refer to liquified petroleum gas and other petroleum products collectively as "LPG." We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins and at major market hubs in the United States and Canada.

We are one of the largest midstream crude oil companies in North America. As of December 31, 2004, we owned approximately 15,000 miles of active crude oil pipelines, approximately 37 million barrels of active terminalling and storage capacity and over 400 transport trucks. Currently, we handle an average of over 2.4 million barrels per day of physical crude oil through our extensive network of assets located in major oil producing regions of the United States and Canada. Our operations consist of two operating segments: (i) pipeline operations ("Pipeline Operations") and (ii) gathering, marketing, terminalling and storage operations ("GMT&S"). Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets.

Overview of Operating Results and Significant Activities

During 2004, we recognized net income and earnings per limited partner unit of $130.0 million and $1.89, respectively, both of which were substantial increases over 2003 and 2002. The results for 2004 as compared to the two previous years include significant contributions from acquisitions completed during 2003 and 2004.

The following significant activities impacted our operations, operating results or our financial position during 2004:

- Effective April 1, 2004, we acquired all of the North American crude oil and pipeline operations of Link Energy LLC ("Link") for approximately $332 million. Additionally, effective March 1, 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.5 million (including a $15.8 million deposit paid in December 2003). The principal assets of the Shell entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System.

- We maintained the relative strength of our overall capital structure and maintained substantial liquidity through a series of equity issuances and senior notes issuances. We also entered into new credit facilities which expanded and extended the size and maturity of our prior facilities. See "—Liquidity and Capital Resources."

- We realized year over year growth in segment profit from both our pipeline operations segment and our GMT&S segment. This growth was primarily driven by (i) the impact of the current year acquisitions subsequent to their acquisition during 2004, (ii) inclusion of a full year contribution from those assets that we acquired during 2003, and (iii) the positive results, in relatively volatile market conditions, of our counter-cyclically balanced activities in our GMT&S segment.

- We changed our method of accounting for pipeline linefill in third party assets resulting in a cumulative effect of change in accounting principle charge of $3.1 million. See "—Recent Accounting Pronouncements and Change in Accounting Principle."

- Under generally accepted accounting principles, we are required to recognize an expense when vesting of units under our 1998 Long-Term Incentive Plan ("1998 LTIP") becomes probable as determined by management. Our results of operations for 2004 include a charge of $7.9 million.

- Recognized a foreign exchange gain of $5.0 million related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability of our Canadian subsidiary. This is primarily attributable to our LPG business, a substantial amount of which is transacted in U.S. Dollars.

- Recognized a lower-of-cost-or-market inventory charge of approximately $2.0 million related to a valuation adjustment on our LPG inventory. This charge is linked to the foreign exchange gain mentioned above, and is effectively a partial reversal of that gain. This is primarily because of a stronger Canadian dollar relative to the U.S. dollar at the date of measurement compared to at the time of purchase.

- Recognized a non-cash gain of approximately $1.0 million resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").

- Recognized a non-cash charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks. As a result, we were able to maintain most of our margins.

Prospects for the Future

We believe we have access to equity and debt capital and that we are well situated to optimize our position in and around our existing assets and to expand our asset base by continuing to consolidate, rationalize and optimize the North American crude oil infrastructure. We have deliberately configured our assets to provide a counter-cyclical balance between our gathering and marketing activities and our terminalling and storage activities. We believe the combination of these balanced activities adds stability to the portion of our business that is highly cyclical, and with our relatively stable, fee-based pipeline assets, enables us to generate stable financial results.

During 2004 we strengthened our business by expanding our asset base through acquisitions and internal growth projects. We operate in a mature industry and believe that our primary source of growth will come from acquisitions, and we believe that there are opportunities for acquisitions. We will continue to pursue the purchase of midstream crude oil assets, and we will also continue to initiate projects designed to optimize crude oil flows in the areas in which we operate. We believe the outlook is positive for, and have a strategic initiative of increasing our participation in, the importing of foreign crude oil, primarily through building a meaningful asset presence to enable us to receive foreign crude oil via the Gulf Coast. We also believe there are opportunities for us to grow our LPG business. In addition, we believe we can, and will pursue opportunities to, leverage our assets, business model, knowledge and expertise into investments in businesses complementary to our crude oil and LPG activities. Although we believe that we are well situated in the North American crude oil infrastructure, we face various operational, regulatory and financial challenges that may impact our ability to execute our strategy as planned. See "—Risk Factors Related to Our Business" for further discussion of these items. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

Acquisitions

We completed a number of acquisitions in 2004, 2003 and 2002 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 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.

2004 Acquisitions

In 2004, we completed several acquisitions for aggregate consideration of approximately $549.5 million. The aggregate consideration includes cash paid, estimated transaction costs and assumed liabilities and net working capital items. The following table summarizes our 2004 acquisitions, and a description of each of these follows the table:

Acquisition	Effective Date	Acquisition Cost (in millions)	Operating Segment
Capline and Capwood Pipeline Systems	03/01/04	$158.5	Pipeline
Link Energy LLC	04/01/04	332.3	Pipeline/GMT&S
Cal Ven Pipeline System	05/01/04	19.0	Pipeline
Schaefferstown Propane Storage Facility	08/25/04	32.0	GMT&S
Other	various	7.7	GMT&S
Total 2004 Acquisitions		$549.5	

Capline and Capwood Pipeline Systems. In March 2004, we completed the acquisition of all of Shell Pipeline Company LP's interests in two entities for approximately $158.0 million in cash (including a $15.8 million deposit paid in December 2003) and approximately $0.5 million of transaction and other costs. In December 2003, subsequent to the announcement of the acquisition and in anticipation of closing, we issued approximately 2.8 million common units for net proceeds of approximately $88.4 million, after paying approximately $4.1 million of transaction costs. The proceeds from this issuance were used to pay down the outstanding balances under our revolving credit facility. At closing, the cash portion of this acquisition was funded from cash on hand and borrowings under our revolving credit facility.

The principal assets of the entities are: (i) an approximate 22% undivided joint interest in the Capline Pipeline System, and (ii) an approximate 76% undivided joint interest in the Capwood Pipeline System. The Capline Pipeline System is a 633-mile, 40-inch mainline crude oil pipeline originating in St. James, Louisiana, and terminating in Patoka, Illinois. The Capwood Pipeline System is a 57-mile, 20-inch mainline crude oil pipeline originating in Patoka, Illinois, and terminating in Wood River, Illinois. The results of operations and assets from this acquisition (the "Capline acquisition") have been included in our consolidated financial statements and in our pipeline operations segment since March 1, 2004. These pipelines provide one of the primary transportation routes for crude oil shipped into the Midwestern U.S. and delivered to several refineries and other pipelines.

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

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

Link Energy LLC. On April 1, 2004, we completed the acquisition of all of the North American crude oil and pipeline operations of Link for approximately $332 million, including $268 million of cash and approximately $64 million of net liabilities assumed and acquisition related costs. The Link crude oil business consists of approximately 7,000 miles of active crude oil pipeline and gathering systems, over 10 million barrels of active crude oil storage capacity, a fleet of approximately 200 owned or leased trucks and approximately 2 million barrels of crude oil linefill and working inventory. The Link assets complement our assets in West Texas and along the Gulf Coast and allow us to expand our presence in the Rocky Mountain and Oklahoma/Kansas regions. The results of operations and assets from this acquisition (the "Link acquisition") have been included in our consolidated financial statements and both our pipeline operations and GMT&S operations segments since April 1, 2004.

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

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

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

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

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

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

Cal Ven Pipeline System. On May 7, 2004 we completed the acquisition of the Cal Ven Pipeline System from Cal Ven Limited, a subsidiary of Unocal Canada Limited. The total purchase price was approximately $19 million, including transaction costs. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The Cal Ven Pipeline System includes approximately 195 miles of 8-inch and 10-inch gathering and mainline crude oil pipelines. The system is located in northern Alberta and delivers crude oil into the Rainbow Pipeline System. The Rainbow Pipeline System then transports the crude south to the Edmonton market, where it can be used in local refineries or shipped on connecting pipelines to the U.S. market. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our pipeline operations segment since May 1, 2004.

Schaefferstown Propane Storage Facility. In August 2004, we completed the acquisition of the Schaefferstown Propane Storage Facility from Koch Hydrocarbon, L.P. The total purchase price was approximately $32 million, including transaction costs. In connection with the transaction, we also acquired an additional $14.2 million of inventory. The transaction was funded through a combination of cash on hand and borrowings under our revolving credit facilities. The results of operations and assets from this acquisition have been included in our consolidated financial statements and our gathering, marketing, terminalling and storage operations segment since August 25, 2004.

2003 Acquisitions

During 2003, we completed ten acquisitions for aggregate consideration of approximately $159.5 million. The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. The acquisitions were initially financed with borrowings under our credit facilities, which were subsequently repaid with a portion of the proceeds from our equity issuances and the issuance of senior notes. See "—Liquidity and Capital Resources." The businesses acquired during 2003 impacted our results of operations commencing on the effective date of each acquisition as indicated below. These acquisitions included mainline crude oil pipelines, crude oil gathering lines, terminal and storage facilities, and an underground LPG storage facility. With the exception of $0.5 million that was allocated to goodwill and other intangible assets and $4.7 million associated with crude oil linefill and working inventory, the remaining aggregate purchase price was allocated to property and equipment. The following table details our 2003 acquisitions (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Red River Pipeline System	02/01/03	$19.4	Pipeline
Iatan Gathering System	03/01/03	24.3	Pipeline
Mesa Pipeline Facility	05/05/03	2.9	Pipeline
South Louisiana Assets[(1)]	06/01/03	13.4	Pipeline/G,M,T,&S
Alto Storage Facility	06/01/03	8.5	G,M,T&S
Iraan to Midland Pipeline System	06/30/03	17.6	Pipeline
ArkLaTex Pipeline System	10/01/03	21.3	Pipeline
South Saskatchewan Pipeline System	11/01/03	47.7	Pipeline
Atchafalaya Pipeline System[(2)]	12/01/03	4.4	Pipeline
Total 2003 Acquisitions		$159.5	

(1) Includes a 33.3% interest in Atchafalaya Pipeline L.L.C.

(2) Includes two acquisitions each for 33.3% interests in Atchafalaya Pipeline L.L.C.

2002 Acquisitions

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 9.0 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") for approximately $324 million. 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 entire purchase price was allocated to property and equipment.

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. The Rancho Pipeline System was taken out of service in March 2003, pursuant to the operating agreement. See "Business and Properties—Dispositions—Shutdown and Sale of Rancho Pipeline System."

Other 2002 Acquisitions. During February and March of 2002, we completed two other acquisitions for aggregate consideration totaling $15.9 million, with effective dates of February 1, 2002 and March 31, 2002, respectively. These acquisitions include an equity interest in a crude oil pipeline company and crude oil gathering and marketing assets.

Critical Accounting Policies and Estimates

Our critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements. 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.

Purchase and Sales Accruals. We routinely make accruals based on estimates for certain components of our revenues and cost of sales due to the timing of compiling billing information, receiving third-party information and reconciling our records with those of third parties. Where applicable, these accruals are based on nominated volumes expected to be purchased, transported and subsequently sold. Uncertainties involved in these estimates include levels of production at the wellhead, access to certain qualities of crude oil, pipeline capacities and delivery times, utilization of truck fleets to transport volumes to their destinations, weather, market conditions and other forces beyond our control. These estimates are generally associated with a portion of the last month of each reporting period. We currently estimate that less than 2% of total annual revenues and cost of sales are recorded using estimates and less than 5% of total quarterly revenues and cost of sales are recorded using estimates. Accordingly, a variance from this estimate of 10% would impact the respective line items by less than 1% on both an annual and quarterly basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Mark-to-Market Accrual. 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 due to a difference in assumptions applied such as the estimate of prevailing market prices, volatility, correlations and other factors and may not be reflective of the price at which they can be settled due to the lack of a liquid market. Less than 1% of total revenues are based on estimates derived from these models. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Contingent Liability Accruals. We accrue reserves for contingent liabilities including, but not limited to, environmental remediation, insurance claims, asset retirement obligations 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. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment, costs of medical care associated with worker's compensation and employee health insurance claims, and the possibility of existing legal claims giving rise to additional claims. Our estimates for contingent liability accruals are increased or decreased as additional information is obtained or resolution is achieved. A variance of 10% in our aggregate estimate for the contingent liabilities discussed above would have an approximate $2.3 million impact on earnings. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

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 period subsequent to the acquisition. In addition, in conjunction with the 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 customer 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 and, to the extent available, third party assessments. Uncertainties associated with these estimates include changes in production decline rates, production interruptions, fluctuations in refinery capacity or product slates, economic obsolescence factors in the area and potential future sources of cash flow. Although the resolution of these uncertainties has not historically had a material impact on our results of operations or financial condition, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts.

Recent Accounting Pronouncements and Change in Accounting Principle

Recent Accounting Pronouncements

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

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

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

Earnings per Unit. In March 2004, the Emerging Issues Task Force issued Issue No. 03-06 ("EITF 03-06"), "Participating Securities and the Two-Class Method under FASB Statement No. 128." EITF 03-06 addresses a number of questions regarding the computation of earnings per share by companies that have issued securities, other than common stock, that contractually entitle the holder to participate in dividends and earnings of the company when, and if, it declares dividends on its common stock. The issue also provides further guidance in applying the two-class method of calculating earnings per share, clarifying what constitutes a participating security and how to apply the two-class method of computing earnings per share once it is determined that a security is participating, including how to allocate undistributed earnings to such a security. EITF 03-06 was effective for fiscal periods beginning after March 31, 2004. The adoption of EITF 03-06 may have an impact on earnings per limited partner unit in future periods if net income exceeds distributions or if other participating securities are issued. The effect of applying EITF 03-06 on prior periods was not material except for the year ended December 31, 2000, which has been restated as shown below.

Basic and Diluted Income Before Extraordinary Item and Cumulative Effect of Change in Accounting Principle per Limited Partner Unit:

	For the Year Ended December 31, 2000
Prior to the adoption of SFAS 145[1] or EITF 03-06	$2.64
After the adoption of SFAS 145 but prior to the adoption of EITF 03-06	$2.20
After the adoption of both SFAS 145 and EITF 03-06	$2.13

(1) SFAS 145 "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13 and Technical Corrections."

Change in Accounting Principle

During the second quarter of 2004, we changed our method of accounting for pipeline linefill in third party assets. Historically, we have viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we have not included linefill barrels in the same average costing calculation as our operating inventory, but instead have carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we have historically classified as a portion of "Pipeline Linefill" on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in "Inventory" (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of "Inventory" (a current asset), at average cost, and into "Inventory in Third Party Assets" (a long-term asset), which is now reflected as a separate line item within other assets on the consolidated balance sheet.

This change in accounting principle was effective January 1, 2004 and is reflected in our consolidated statement of operations for the year ended December 31, 2004 and our consolidated balance sheet as of December 31, 2004. The cumulative effect of this change in accounting principle as of January 1, 2004, is a charge of approximately $3.1 million, representing a reduction in Inventory of approximately $1.7 million, a reduction in Pipeline Linefill of approximately $30.3 million and an increase in Inventory in Third Party Assets of $28.9 million. The pro forma impact for the periods ended December 31, 2003 and 2002 is detailed below:

	Reported Year Ended December 31,		Impact of Change in Accounting Principle Year Ended December 31,		Pro Forma Year Ended December 31,	
	2003	2002	2003	2002	2003	2002
	(in millions, except per unit amounts)					
Net income	$59.5	$65.3	$2.0	$(0.1)	$61.5	$65.2
Basic income per limited partner unit	$1.01	$1.34	$0.04	$—	$1.05	$1.34
Diluted income per limited partner unit	$1.00	$1.34	$0.04	$—	$1.04	$1.34

In conjunction with this change in accounting principle, we have classified cash flows associated with purchases and sales of linefill on assets that we own as cash flows from investing activities instead of the historical classification of cash flows from operating activities. Accordingly, our statement of cash flows for the years ended December 31, 2003 and 2002 has been revised to reclassify the cash paid for linefill in assets owned from operating activities to investing activities. As a result of this change in classification, net cash provided by operating activities for the years ended December 31, 2003 and 2002 increased to $115.3 million from $68.5 million and to $185.0 million from $173.9 million, respectively. Net cash used in investing activities for the years ended December 31, 2003 and 2002 increased to $272.1 million from $225.3 million and $374.8 million from $363.8 million, respectively.

Results of Operations

Analysis of Operating Segments

Our operations consist of two operating segments: (i) Pipeline Operations and (ii) GMT&S Operations. Through our pipeline segment, we engage in interstate and intrastate crude oil pipeline transportation and certain related margin activities. Through our GMT&S segment, we engage in purchases and resales of crude oil and LPG at various points along the distribution chain and we operate certain terminalling and storage assets. We believe that the combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flow. In a contango market (oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow.

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. Therefore, we look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. Management compensates for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance costs, which keep the actual value of our principal fixed assets from declining. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are not considered maintenance capital expenditures. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 14 "Operating Segments" in the "Notes to the Consolidated Financial Statements" for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle. The following table reflects our results of operations and maintenance capital for each segment.

	Pipeline Operations	GMT&S Operations
	(in millions)	
Year Ended December 31, 2004[1]		
Revenues	$874.9	$20,223.5
Purchases	(554.6)	(19,992.8)
Field operating costs (excluding LTIP charge)	(121.1)	(97.5)
LTIP charge—operations	(0.1)	(0.8)
Segment G&A expenses (excluding LTIP charge)[2]	(38.1)	(37.7)
LTIP charge—general and administrative	(3.8)	(3.2)
Segment profit	$157.2	$91.5
Noncash SFAS 133 impact[3]	$—	$1.0
Maintenance capital	$8.3	$3.0
Year Ended December 31, 2003[1]		
Revenues	$658.6	$11,985.6
Purchases	(487.1)	(11,799.8)
Field operating costs (excluding LTIP charge)	(60.9)	(73.3)
LTIP charge—operations	(1.5)	(4.3)
Segment G&A expenses (excluding LTIP charge)[2]	(18.3)	(31.6)
LTIP charge—general and administrative	(9.5)	(13.5)
Segment profit	$81.3	$63.1
Noncash SFAS 133 impact[3]	$—	$0.4
Maintenance capital	$6.4	$1.2
Year Ended December 31, 2002[1]		
Revenues	$486.2	$7,921.8
Purchases	(362.2)	(7,765.1)
Field operating costs	(40.1)	(66.3)
Segment G&A expenses[2]	(13.2)	(31.5)
Segment profit	$70.7	$58.9
Noncash SFAS 133 impact[3]	$—	$0.3
Maintenance capital	$3.4	$2.6

(1) Revenues and purchases include intersegment amounts.

(2) Segment 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. The proportional allocations by segment require judgement by management and will continue to be based on the business activities that exist during each period.

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

Pipeline Operations

As of December 31, 2004, we owned approximately 15,000 miles (of which approximately 13,000 miles are included in our pipeline segment) of active 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 and third party leases of pipeline capacity (collectively referred to as "tariff activities"), as well as barrel exchanges and buy/sell arrangements (collectively referred to as "pipeline margin activities"). In connection with certain of our merchant activities conducted under our gathering and marketing business, we are also shippers on certain of our own pipelines. These transactions are conducted at published tariff rates and eliminated in consolidation. Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit 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 field costs of operating the pipeline. Segment profit 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,		
	2004	2003	2002
		(in millions)	
Operating Results[1]			
Revenues			
Tariff activities	$299.7	$153.3	$103.7
Pipeline margin activities	575.2	505.3	382.5
Total pipeline operations revenues	874.9	658.6	486.2
Costs and Expenses			
Pipeline margin activities purchases	(554.6)	(487.1)	(362.2)
Field operating costs (excluding LTIP charge)	(121.1)	(60.9)	(40.1)
LTIP charge—operations	(0.1)	(1.4)	—
Segment G&A expenses (excluding LTIP charge)[2]	(38.1)	(18.3)	(13.2)
LTIP charge—general and administrative	(3.8)	(9.6)	—
Segment profit	$157.2	$81.3	$70.7
Maintenance capital	$8.3	$6.4	$3.4
Average Daily Volumes (thousands of barrels per day)[3]			
Tariff activities			
All American	54	59	65
Basin	265	263	93
Link acquisition	283	N/A	N/A
Capline	123	N/A	N/A
Other domestic	424	299	219
Canada	263	203	187
Total tariff activities	1,412	824	564
Pipeline margin activities	74	78	73
Total	1,486	902	637

(1) Revenues and purchases include intersegment amounts.

(2) Segment 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. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

(3) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Revenues from both our tariff activities and our pipeline margin activities have increased over the three year period ended December 31, 2004. The increase in revenues from tariff activities in both the 2004 and 2003 periods is primarily related to increased volumes resulting from our acquisition activities as discussed further below. The increase in revenue from our pipeline margin activities was related to higher average prices for crude oil sold and transported on our SJV gathering system in each of the years compared to the year prior. The increase in 2004 was partially offset by lower buy/sell volumes (as compared to 2003), while the 2003 period benefitted from higher buy/sell volumes (as compared to 2002). Because the barrels that we buy and sell are generally indexed to the same pricing indices, revenues and purchases will increase and decrease with changes in market prices without significant changes to our margins related to those purchases and sales.

Our buy/sell arrangements in our pipeline segment consisted of the following:

	Year Ended December 31,		
	2004	**2003**	**2002**
Barrels per day	12,000	17,000	10,000
Revenues (in millions)	$149.8	$166.2	$95.8
Purchases (in millions)	(142.5)	(159.2)	(87.6)
Margin (in millions)	$7.3	$7.0	$8.2

Increases in segment profit, our primary measure of segment performance, were driven by the following:

- Increased volumes and related tariff revenues—The increase in volumes and related tariff revenues in 2004 versus 2003 is primarily related to the Link acquisition, the Capline acquisition and other acquisitions completed during 2004 and late 2003. Similar increases in 2003 compared to 2002 are related to the acquisitions made in 2003, as well as the inclusion of the assets acquired in 2002 for a full year as compared to only a portion of 2002.

- Higher realized prices on our loss allowance oil—Higher crude oil prices during 2004 as compared to 2003 (the NYMEX average for 2004 was $41.29 per barrel versus $31.08 per barrel in 2003) have resulted in increased revenues related to loss allowance oil.

- Increased field operating costs—Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004 and late 2003 is the principal driver of the increase in field operating costs for 2004. The increased costs are primarily in payroll and benefits and utilities. The 2004 results also include a $1.7 million charge for a pipeline release of oil. In addition, costs related to pipeline and storage regulation have increased by approximately $2 million in 2004. The increase in field operating costs in 2003 as compared to 2002 was predominantly related to growth from acquisitions and higher utility costs. The 2003 period also includes a $1.4 million LTIP charge and a $1.0 million charge for a release of oil from a pipeline.

- Increased segment G&A expenses—The increase in segment G&A expenses in 2004 is primarily related to the Link acquisition coupled with the increase in the percentage of indirect costs allocated to the pipeline operations segment in the 2004 period as our pipeline operations have grown. G&A costs have also increased because of increased headcount from our continued growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance. Costs related to section 404 compliance were $2.6 million in 2004. These items were partially offset by the inclusion of an LTIP charge of approximately $9.6 million in the 2003 period compared to $3.8 million in the 2004 period. The increase in 2003 as compared to 2002 is primarily related to the LTIP charge mentioned above, an overall increase in costs from our continued growth from acquisitions and increased indirect costs allocated to the pipeline operations segment as operations grew.

As discussed above, the increase in pipeline operations segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2004 and 2003 that have impacted our results of operations. The following presentation summarizes the revenue and volume impact of recent acquisitions.

	Year Ended December 31,					
	2004		2003		2002	
	Revenues	Volumes	Revenues	Volumes	Revenues	Volumes
	(volumes in thousands of barrels per day and revenues in millions)					
Tariff activities[1][2]						
2004 acquisitions	$115.6	525	$N/A	N/A	$N/A	N/A
2003 acquisitions	39.7	170	14.8	82	N/A	N/A
2002 acquisitions	54.6	327	54.2	344	23.1	171
All other pipeline systems	89.8	390	84.3	398	80.6	393
Total tariff activities	$299.7	1,412	$153.3	824	$103.7	564

(1) Revenues include intersegment amounts.

(2) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

The increase in 2004 is predominately related to (i) the inclusion of an average of 283,000 barrels per day and $79.3 million of revenues from the pipelines acquired in the Link acquisition, (ii) the inclusion of an average of approximately 123,000 barrels per day and $25.9 million of revenues from the Capline pipeline system and (iii) 119,000 barrels per day and $10.4 million of revenues from other 2004 acquisitions. Additionally, volumes and revenues have increased as a result of the inclusion for the full year of 2004 of several pipeline systems acquired during 2003 as compared to only a portion of the year in 2003 (See "Acquisitions"), coupled with higher realized prices on our loss allowance oil. Revenues from all other pipeline systems increased in the 2004 period, primarily related to slightly higher volumes on various systems. The appreciation of Canadian currency also favorably impacted revenues. The Canadian dollar to U.S. dollar exchange rate appreciated to an average of 1.30 to 1 for the year ended December 31, 2004, compared to an average of 1.40 to 1 for the year ended December 31, 2003.

The increase in 2003 relates to various acquisitions completed in 2003 along with the inclusion of assets acquired in 2002 for an entire year compared to only a portion of 2002.

Maintenance Capital

For the periods ended December 31, 2004, 2003 and 2002, maintenance capital expenditures were approximately $8.3 million, $6.4 million and $3.4 million, respectively for our pipeline operations segment. The increase in 2004 is because of the growth of our business, primarily related to the Link acquisition. The increase in 2003 is related to our continued growth, primarily through acquisitions.

Gathering, Marketing, Terminalling and Storage Operations

As of December 31, 2004, we owned approximately 37 million barrels of active 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." Approximately 13.6 million barrels of our 37 million barrels of tankage is used primarily in our GMT&S Operations segment and the balance is used in our Pipeline Operations segment. On a stand-alone basis, segment profit from terminalling and storage activities is dependent on the throughput of volumes, the volume of crude oil stored and the level of fees generated from our terminalling and storage services. Our terminalling and storage activities are integrated with our gathering and marketing activities and the level of tankage that we allocate for our arbitrage activities (and therefore not available for lease to third parties) varies throughout crude oil price cycles. This integration enables us to use our storage tanks in an effort to counter-cyclically balance and hedge our gathering and marketing activities. In a contango market (when oil prices for future deliveries are higher than for current deliveries), we use our tankage to improve our gathering margins by storing crude oil we have purchased at lower prices in the current month for delivery at higher prices in future months. In a backwardated market (when oil prices for future deliveries are lower than for current deliveries), we use less storage capacity, but increased marketing margins (premiums for prompt delivery) provide an offset to this reduced cash flow. We believe that this combination of our terminalling and storage activities and gathering and marketing activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows.

Our revenues from gathering and marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, plus the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and the sale, revenues and costs related to purchases will increase and decrease with changes in market prices. However, the margins related to those purchases and sales will not necessarily have corresponding increases and decreases. For example, our revenues increased approximately 69% in 2004 compared to 2003, while our segment profit increased approximately 45% in the same period.

Revenues from our GMT&S operations were approximately $20.2 billion, $12.0 billion and $7.9 billion for the years ended December 31, 2004, 2003 and 2002, respectively. Revenues and costs related to purchases for the 2004 period were impacted by higher average prices and higher volumes as compared to the 2003 period. Approximately 60% of the increase in revenues resulted from higher average prices in the 2004 period and the remainder was attributable to increased sales volumes. The average NYMEX price for crude oil was $41.29 per barrel and $31.08 per barrel for the years ended December 31, 2004 and 2003, respectively. The increase in revenues and costs related to purchases in 2003 was related to higher average prices and higher volumes in 2003 as compared to 2002. The average NYMEX price for crude oil was $26.10 per barrel in 2002.

Our buy/sell arrangements in our GMT&S segment consisted of the following:

	Year Ended December 31,		
	2004	**2003**	**2002**
Barrels per day[(1)]	790,000	545,000	460,000
Revenues (in millions)[(1)]	$11,247.0	$6,124.9	$4,140.8
Purchases (in millions)[(1)]	(11,137.7)	(5,967.2)	(4,026.2)
Margin (in millions)	$109.3	$157.7	$114.6

(1) Include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances.

Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. Although we believe that the combination of our lease gathering business and our storage assets provides a counter-cyclical balance that provides stability in our margins, these margins are not fixed and may vary from period to period. In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) crude oil lease gathered volumes and LPG sales volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our Gathering, Marketing, Terminalling and Storage Operations segment for the periods indicated:

	December 31,		
	2004	2003	2002
	(in millions, except per barrel amounts)		
Operating Results[1]			
Revenues	$20,223.5	$11,985.6	$7,921.8
Purchases and related costs	(19,992.8)	(11,799.8)	(7,765.1)
Field operating costs (excluding LTIP charge)	(97.5)	(73.3)	(66.3)
LTIP charge—operations	(0.8)	(4.3)	—
Segment G&A expenses (excluding LTIP charge)[2]	(37.7)	(31.6)	(31.5)
LTIP charge—general and administrative	(3.2)	(13.5)	—
Segment profit	$91.5	$63.1	$58.9
Noncash SFAS 133 impact[3]	$1.0	$0.4	$0.3
Maintenance capital	$3.0	$1.2	$2.6
Segment profit per barrel[4]	$0.39	$0.36	$0.36
Average Daily Volumes (thousands of barrels per day)[5]			
Crude oil lease gathered	589	437	410
Crude oil bulk purchases	148	90	68
Total	737	527	478
LPG sales	48	38	35

(1) Revenue and purchases include intersegment amounts.

(2) Segment 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. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during each period.

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

(4) Calculated based on crude oil lease gathered barrels and LPG sales barrels.

(5) Volumes associated with acquisitions represent total volumes transported for the number of days we actually owned the assets divided by the number of days in the period.

Increases in segment profit, our primary measure of segment performance, were driven by the following:

- Increased crude oil lease gathered volumes and LPG sales volumes—The crude oil volumes gathered from producers, using our assets or third-party assets, have increased by approximately 35% in 2004. The increase is primarily related to the Link acquisition, which has offset natural production declines. In addition, we marketed 48,000 barrels per day of LPG during 2004 compared to 38,000 barrels per day in 2003.

- Favorable market conditions—During 2004, market conditions were favorable as the crude oil market experienced significant volatility and the market shifted between backwardation and contango multiple times during the year. Additionally, price differentials between grades of crude oil were wider than normal, enhancing results. The NYMEX benchmark price of crude ranged from $32.20 to $55.65 during the period. This volatile market allowed us to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the period. The market conditions in 2003 were also favorable as there was relatively high volatility and strong backwardation throughout the period. During 2003, the NYMEX benchmark price of crude ranged from $25.04 to $39.99 per barrel. Additionally, in the first quarter of 2003, cold weather throughout the U.S. and Canada led to increased LPG sales and higher margins.

- Change in impact from the SFAS 133 mark-to-market adjustment—The 2004 period included a non-cash gain of approximately $1.0 million resulting from the mark-to-market of open derivative instruments pursuant to SFAS 133, while the 2003 and 2002 periods included non-cash gains of approximately $0.4 million and $0.3 million, respectively.

- Impact of change in Canadian dollar to U.S. dollar exchange rate—The 2004 period includes a foreign exchange gain of $5.0 million. The gain is related to the impact of changes in the Canadian dollar to U.S. dollar exchange rate on a net U.S. dollar denominated liability of our Canadian subsidiary whose functional currency is the Canadian dollar. This is primarily attributable to our LPG business, a substantial amount of which is transacted in US Dollars.

- Lower-of-cost-or-market inventory adjustment—The 2004 period included a charge of approximately $2.0 million related to a valuation adjustment on our LPG inventory. This charge is linked to the foreign exchange gain mentioned above, and is effectively a partial reversal of that gain.

- Increased tankage available to our gathering and marketing business—As a result of various acquisitions and expansion at our Cushing Terminal, the average amount of tankage available increased to 12.7 million barrels in 2004 from 11.0 million barrels in 2003 and 10 million barrels in 2002.

- Increased field operating costs—Our continued growth, primarily from the Link acquisition is the primary driver of the increase in field operating costs for 2004 as compared to 2003. This increase was partially offset by the $4.3 million charge related to our 1998 LTIP in the 2003 period compared to $0.8 million in 2004. Field operating costs increased in 2003 as compared to 2002 primarily because of the 1998 LTIP charge mentioned above. The remaining increase was partially related to our growth in 2003, primarily related to acquisitions, coupled with increased regulatory compliance activities and higher fuel costs.

- Increased segment G&A expenses—G&A increased in 2004, primarily related to an increase in employees resulting from continued growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance partially offset by a decrease in the percentage of indirect costs allocated to the GMT&S operations segment as the growth in our pipeline operations segment has outpaced growth in our GMT&S operations segment. Costs related to section 404 compliance were $1.9 million in 2004. The increase is partially offset by the $13.5 million charge related to our LTIP in 2003 compared to $3.2 million in 2004. The increase in G&A in 2003 as compared to 2002 is primarily related to the 1998 LTIP charge mentioned above, partially offset by the decrease in indirect costs allocated to the GMT&S segment from period to period as our Pipeline Operations segment has grown.

The impact of the items discussed above resulted in segment profit per barrel (calculated based on our lease gathered crude oil and LPG barrels) of $0.39 per barrel for 2004, compared to $0.36 for both 2003 and 2002.

Maintenance capital

For the periods ended December 31, 2004, 2003 and 2002, maintenance capital expenditures were approximately $3.0 million, $1.2 million and $2.6 million, respectively for our gathering, marketing, terminalling and storage operations segment. The increase in 2004 as compared to 2003 is primarily related to the Link acquisition. The decrease in 2003 as compared to 2002 was primarily because of a reduction in costs associated with information systems and the replacement of a portion of our fleet in 2002.

Other Income and Expenses

Unallocated G&A Expenses

Segment G&A expenses include the costs directly associated with the segments, as well as a portion of corporate overhead costs considered allocable. Total G&A expenses were $82.8 million, $73.0 million and $45.7 million for the years ended December 31, 2004, 2003 and 2002, respectively. We have included in the above segment discussion the G&A expenses for each of these years that were attributable to our segments either directly or by allocation. During 2002, we were unsuccessful in our pursuit of several sizable acquisition opportunities determined by auction and one negotiated transaction that had advanced nearly to the execution stage when it was abruptly terminated by the seller. As a result, our 2002 results reflect a $1.0 million charge to G&A expenses associated with the third-party costs of these unsuccessful transactions. This charge was not allocated to the segments.

Depreciation and Amortization

Depreciation and amortization expense was $67.2 million for the year ended December 31, 2004, compared to $46.8 million and $34.1 million for the years ended December 31, 2003 and 2002, respectively. The increase in 2004 relates primarily to the assets from our 2004 acquisitions and our various 2003 acquisitions being included for the full year versus only a part of the year in 2003. In addition, 2004 includes approximately $4.2 million of depreciation of trucks and trailers under capital leases. Amortization of debt issue costs was $2.5 million in 2004, compared to $3.8 million in 2003.

The increase in 2003 over 2002 relates primarily to the inclusion of the assets from the Shell acquisition for the entire year as compared to a portion of 2002. Additionally, several acquisitions were completed during the year along with various capital projects. Amortization of debt issue costs was flat between the two years.

Interest Expense

Interest expense was $46.7 million for the year ended December 31, 2004, compared to $35.2 million and $29.1 million for the years ended December 31, 2003 and 2002, respectively. In 2004, our average debt balance was $859.5 million. This balance consisted of fixed rate senior notes averaging $585.8 million and borrowings under our revolving credit facilities averaging $273.7 million. During the 2003 period, our average debt balance was approximately $525.5 million and consisted of fixed rate senior notes averaging $214.4 million and borrowings under our revolving credit facilities averaging $311.1 million. The higher average debt balance in 2004 was primarily related to the portion of our acquisitions that were not refinanced with equity. Our financial growth strategy is to fund our acquisitions using a balance of debt and equity.

During the third quarter of 2004, we issued $175 million of five year senior unsecured notes and $175 million of 12 year senior unsecured notes. These issuances resulted in an increase in the average amount of longer term and higher cost fixed rate debt outstanding in 2004 to approximately 68% as compared to approximately 41% in 2003. During 2004 and 2003, the average three-month LIBOR rate was 1.6% and 1.2%, respectively.

The higher average debt balance in 2004 resulted in additional interest expense of approximately $16.8 million, while at the same time our commitment and other fees decreased by approximately $0.4 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.0% for 2004 compared to 6.0% for 2003. The lower weighted average rate decreased interest expense by approximately $4.9 million in 2004 compared to 2003.

The increase in 2003 compared to 2002 was primarily related to an increase in the average debt balance during the 2003 period to approximately $525.5 million from approximately $444.6 million in the 2002 period, which resulted in additional interest expense of approximately $5.0 million. The higher average debt balance was primarily due to the portion of the Shell acquisition that was not financed with equity. This debt was outstanding for all of 2003 versus only a portion of 2002. Also, increased commitment and other fees coupled with lower capitalized interest resulted in approximately $2.2 million of the increase in the 2003 period. Our weighted average interest rate decreased slightly during 2003 to 6.0% versus 6.2% in 2002, which decreased our interest expense by approximately $1.1 million. Although the change in our weighted average interest rate was nominal, the change was the net result of various factors that included an increase in the amount of fixed rate debt with longer maturities, long-term interest rate hedges and declining short-term interest rates. In mid-September 2002, we issued $200 million of ten-year bonds bearing a fixed interest rate of 7.75%. In the fourth quarter of 2002 and the first quarter of 2003, we entered into hedging arrangements to lock in interest rates on approximately $50 million of its floating rate debt. In addition, the average three-month LIBOR rate declined from approximately 1.8% during 2002 to approximately 1.2% during 2003. The net impact of these factors, increased commitment fees and changes in average debt balances decreased the average interest rate by 0.2%.

Other

During the third quarter of 2004, we completed (i) the issuance of 4,968,000 common units and (ii) the issuance of an aggregate of $350 million of senior unsecured notes. We used the proceeds from these issuances to, among other things, repay amounts outstanding under our revolving credit facilities, including all amounts outstanding under the $200 million, 364-day facility we used to fund the Link acquisition. The repayment and termination of this facility resulted in a non-cash charge of approximately $0.7 million associated with the write-off of unamortized debt issue costs. Additionally, during the fourth quarter of 2004, we recognized an impairment charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. The impairment represents the remaining net book value of the idled pipeline system. This pipeline did not support spending the capital necessary to continue service and we shifted the majority of the gathering and transport activities to trucks. As a result, we were able to maintain most of our margins.

During the fourth quarter of 2003 we completed the refinancing of our bank credit facilities with new senior unsecured credit facilities totaling $750 million and a $200 million uncommitted facility for the purchase of hedged crude oil (See "—Liquidity and Capital Resources—Credit Facilities and Long-term Debt"). In addition, during the third quarter of 2003 we made a $34 million prepayment on our Senior secured term B loan in anticipation of the refinancing. The completion of these transactions resulted in a non-cash charge of approximately $3.3 million associated with the write-off of unamortized debt issue costs.

Outlook

This section identifies certain matters of risk and uncertainty that may affect our financial performance and results of operations in the future.

Ongoing Acquisition Activities. Consistent with our business strategy, we are continuously engaged in discussions with potential sellers regarding the possible purchase by us of transportation, gathering, terminalling or storage assets and related businesses. These acquisition efforts often involve assets which, if acquired, would have a material effect on our financial condition and results of operations. In an effort to prudently and economically leverage our asset base, knowledge base and skill sets, management has also expanded its efforts to encompass businesses that are closely related to, or significantly intertwined with, the crude oil business. We can give no assurance that our current or future acquisition efforts will be successful or that any such acquisition will be completed on terms considered favorable to us.

OCS Production. In October 2004, Plains Exploration and Production ("PXP") announced that it had successfully completed an initial development well into the Rocky Point field, which is accessible from the Point Arguello platforms and that drilling operations are underway on a second development well. We can give no assurances, however, that our volumes transported would increase as a result of this drilling activity.

Pipeline Integrity and Storage Tank Testing Compliance. Although we believe our short-term estimates of costs under the pipeline integrity management rules and API 653 (and similar Canadian regulations) are reasonable, a high degree of uncertainty exists with respect to estimating such costs, as we continue to test existing assets and as we acquire new assets.

Sarbanes Oxley Act and Related Legislation. Several regulatory and legislative initiatives were introduced in 2002 and 2003 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 recurrence of similar events. We believe implementation of reforms in connection with these initiatives have added to the costs of doing business for most publicly traded entities, including us as a partnership. These costs will have an adverse impact on future income and cash flow.

Longer Term Outlook. Our longer-term outlook, spanning a period of five or more years, is influenced by many factors affecting the North American crude oil sector. Some of the more significant trends and factors include:

1. Continued overall depletion of U.S. crude oil production.

2. The continuing convergence of worldwide crude oil supply and demand trends.

3. Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels despite rising demand in North America.

4. Industry compliance with the Department of Transportation's adoption of the American Petroleum Institute's standard 653 for testing and maintenance of storage tanks, which will require significant investments to maintain existing crude oil storage capacity or, alternatively, will result in a reduction of existing storage capacity by 2009.

5. The expectation of increased crude oil production from certain North American regions (primarily Canadian oil sands and deepwater Gulf of Mexico sources) that will, of economic necessity, compete for U.S. markets currently being supplied by non-North American foreign crude imports.

We believe the collective impact of these trends, factors and developments, many of which are beyond our control, will result in an increasingly volatile crude oil market that is subject to more frequent short-term swings in market prices and grade differentials and shifts in market structure. In an environment of reduced inventories and tight supply and demand balances, even relatively minor supply disruptions can cause significant price swings. Conversely, despite a relatively balanced market on a global basis, competition within a given region of the U.S. could cause downward pricing pressure and significantly impact regional crude oil price differentials among crude oil grades and locations. Although we believe our business strategy is designed to manage these trends, factors and potential developments, and that we are strategically positioned to benefit from certain of these developments, there can be no assurance that we will not be negatively affected.

Liquidity and Capital Resources

Liquidity

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2004, we had a working capital deficit of approximately $12.5 million, approximately

$420.2 million of availability under our committed revolving credit facilities and $344.6 million of unused capacity under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to compliance with covenants. We believe we are currently in compliance with all covenants. In January 2005, we had additional net borrowings under our uncommitted hedged inventory facility of approximately $236.8 million. The proceeds were used to pay for crude oil stored at December 31, 2004.

Capital Resources

We periodically access the capital markets for both equity and debt financing. In April 2004, we completed the private placement of 3,245,700 units of Class C common units to a group of institutional investors comprised of affiliates of Kayne Anderson Capital Advisors, Vulcan Capital and Tortoise Capital Advisors for $30.81 per unit. Total proceeds from the transaction, after deducting transaction costs and including the general partner's proportionate contribution, was approximately $101 million. In the third quarter of 2004, we completed a public offering of 4,968,000 common units for $33.25 per unit. The offering resulted in gross proceeds of approximately $165.2 million from the sale of units and approximately $3.4 million from our general partner's proportionate capital contribution. Total costs associated with the offering, including underwriter fees and other expenses, were approximately $7.7 million. Net proceeds of $160.9 million were used to permanently reduce outstanding borrowings under the $200 million, 364-day credit facility.

In August 2004, we completed the sale of $350 million of senior notes. We used the net proceeds, after deducting initial purchaser discounts and offering costs, of approximately $345 million to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility we used to fund the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility, which was scheduled to expire in November 2004.

Capital Expenditures

We have made and will continue to make capital expenditures for acquisitions, expansion capital 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 invest approximately $100 million on expansion capital projects during 2005. Our 2005 expansion capital projects include the following notable projects with the estimated cost for the entire year.

	Estimated to be Incurred in 2005
	(in millions)
Capital projects and upgrades associated with the Link acquisition	$18.0
Trenton pipeline expansion	16.0
Cushing Phase V expansion	13.0
Cal Ven fractionator	16.0
Capital projects and upgrades associated with the Shell South Louisiana Assets acquisition	8.0
Other	29.0
	$100.0

In addition, we expect to invest approximately $19.0 million on maintenance capital projects during 2005.

We believe that we have sufficient liquid assets, cash flow 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 an adverse effect on our borrowing capacity.

Cash Flows

Cash flows for the years ended December 31, 2004, 2003 and 2002 were as follows:

	Year Ended December 31,		
	2004	**2003**	**2002**
		(in millions)	
Cash provided by (used in):			
Operating activities	$104.0	$115.3	$185.0
Investing activities	(651.2)	(272.1)	(374.9)
Financing activities	554.5	157.2	189.5

Operating Activities. The primary drivers of our cash flow from operations are (i) the collection of amounts related to the sale of crude oil and LPG and the transportation of crude oil for a fee and (ii) the payment of amounts related to the purchase of crude oil and LPG and other expenses, principally field operating costs and general and administrative expenses. The cash settlement from the purchase and sale of crude oil during any particular month typically occurs within thirty days from the end of the month, except in the months that we store inventory because of contango market conditions or in months that we increase linefill. The storage of crude oil in periods of a contango market can have a material impact on our cash flows from operating activities for the period we pay for and store the crude oil and the subsequent period that we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow on our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. Conversely, cash flow from operations increases in the period we collect the cash from the sale of the stored crude oil. In addition, our cash flow from operating activities is also impacted by the level of LPG inventory stored at period end.

Cash flow from operations was $104.0 million in 2004 and reflects cash generated by our recurring operations that was offset negatively by several factors totaling approximately $100 million. The primary item was a net increase in hedged crude oil and LPG inventory and linefill in third party assets that was financed with borrowings under our credit facilities (approximately $75 million net). Cash flows from operations were also negatively impacted by a decrease of approximately $20 million in prepayments received from counter parties to mitigate credit risk.

Our positive cash flow from operations for 2003 resulted from cash generated by our recurring operations. In addition, cash flow from operating activities was positively impacted by approximately $74 million related to proceeds received in 2003 from the sale of 2002 hedged crude oil inventory and negatively impacted by approximately $100 million related to inventory stored at the end of 2003. The proceeds from the sale of the 2003 stored crude oil were received in the first quarter of 2004. In 2003, we also received approximately $23 million of additional prepayments over the 2002 balance from counter parties to mitigate our credit risk, and paid approximately $6.2 million to terminate an interest rate hedge in conjunction with a change in our capital structure.

Our positive cash flow from operations for 2002 resulted from cash generated by our recurring operations. In addition, we received approximately $93 million of proceeds during 2002 associated with crude oil hedged and stored during 2001. This was partially offset by the payment of approximately $74 million for crude oil purchased and stored during 2002 but for which receipt of the proceeds occurred during 2003. In addition, our 2002 cash flow from operating activities was positively impacted by the collection of approximately $21 million of prepayments from counter parties to mitigate our credit risks and the collection of approximately $9.1 million of amounts that had been outstanding primarily since 1999 and 2000.

Investing Activities. Net cash used in investing activities in 2004, 2003 and 2002 consisted predominantly of cash paid for acquisitions. Net cash used in 2004 was approximately $651 million and was comprised primarily of cash paid for acquisitions of $535 million, which included (i) approximately $294 million for the Link acquisition, (ii) approximately $143 million for the Capline/Capwood acquisition (a deposit of $15.8 million was paid during 2003), (iii) approximately $47 million for the Schafferstown Propane Storage Facility (including approximately $14.2 million of working inventory) and (iv) approximately $51 million related to various other acquisitions. Investing activities for 2004 also included over $115 million of property and equipment construction and capitalized maintenance projects, which includes approximately $34 million related to the Cushing to Broome pipeline construction project.

Net cash used in investing activities 2003 was $272.1 million and was comprised of (i) an aggregate $152.6 million paid primarily for ten acquisitions completed during 2003, (ii) a $15.8 million deposit paid on the Capline acquisition; see "—Acquisitions", (iii) proceeds of approximately $8.5 million from sales of assets, and (iv) $65.4 million paid for additions to property and equipment, including $19.2 million related to the construction of crude oil gathering and transmission lines in West Texas, and (v) crude oil linefill purchases of approximately $47 million, primarily attributable to increased linefill requirements related to 2003 and 2002 acquisitions. Net cash used in 2002 was $374.9 million and was comprised of (i) an aggregate $324.6 million paid for three acquisitions completed during 2002; see "—Acquisitions", and (ii) $40.6 million paid for additions to property and equipment, primarily related to our Cushing expansion and the construction of the Marshall terminal in Canada, and (iii) crude oil linefill purchases of approximately $11 million.

Financing Activities. Cash provided by financing activities in 2004 consisted primarily of $348.1 million of net proceeds from the issuance of senior notes and $262.1 million of net proceeds from the issuance of common units, used primarily to fund acquisitions and pay down outstanding balances on our revolving credit facilities. Net borrowings under our short-term and long-term revolving credit facilities were $107.7 million. In addition, $158.4 million of distributions were paid to our unitholders and general partner.

Cash provided by financing activities in 2003 consisted primarily of $499.7 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 our revolving credit facilities and senior term loans. Net repayments of our short-term and long-term revolving credit facilities and related senior term loans were $215.4 million. In addition, $121.8 million of distributions were paid to our unitholders and general partner. 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 our unitholders and general partner during the year ended December 31, 2002.

Credit Facilities and Long-term Debt

During August 2004, we completed the sale of $175 million of 4.75% senior notes due 2009 and $175 million of 5.88% senior notes due 2016. The 4.75% notes were sold at 99.551% of face value and the 5.88% notes were sold at 99.345% of face value. We used the net proceeds, after deducting initial purchaser discounts and offering costs, of approximately $345 million to repay amounts outstanding under our credit facilities, including the remaining balance under the $200 million, 364-day facility funded in connection with the Link acquisition, and for general partnership purposes. In connection with this repayment, we terminated the facility. Subsequent to the notes offering, we also terminated our $125 million, 364-day facility that was scheduled to expire in November 2004.

In November 2004, we entered into a new $750 million, five-year senior unsecured credit facility, which contains a sub-facility for Canadian borrowings of up to $300 million. The new credit facility extends our maturities, lowers our cost of credit and provides an additional $125 million of liquidity over our previous facilities. This facility can be expanded to $1 billion. As of December 31, 2004, we had approximately $231.8 million outstanding under this credit facility, as well as $98.0 million in letters of credit outstanding, resulting in unused capacity under the facility of approximately $420.2 million.

Also in the fourth quarter of 2004, we amended and renewed our secured hedged inventory facility; increasing the facility to $425 million, with the ability to further increase the facility in the future by an incremental $75 million. This facility is an uncommitted working capital facility, which is used to finance the purchase of hedged crude oil inventory for storage when market conditions warrant. Borrowings under the hedged inventory facility are secured by the inventory purchased under the facility and the associated accounts receivable, and will be repaid with the proceeds from the sale of such inventory. This facility expires in November 2005. As of December 31, 2004, we had approximately $80.4 million outstanding and no letters of credit issued under our hedged crude oil inventory facility resulting in unused uncommitted capacity under this facility of approximately $344.6 million.

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

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

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

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

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

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

Contingencies

Export License Matter. In our gathering and marketing activities, we import and export crude oil from and to Canada. Exports of crude oil are subject to the "short supply" controls of the Export Administration Regulations ("EAR") and must be licensed by the Bureau of Industry and Security (the

"BIS") of the U.S. Commerce Department. In 2002, we determined that we may have violated the terms of our licenses with respect to the quantity of crude oil exported and the end-users in Canada. Export of crude oil except as authorized by license is a violation of the EAR. In October 2002, we submitted to the BIS an initial notification of voluntary disclosure. The BIS subsequently informed us that we could continue to export while previous exports were under review. We applied for and received several new licenses allowing for export volumes and end users that more accurately reflect our anticipated business and customer needs. We also conducted reviews of new and existing contracts and implemented new procedures and practices in order to monitor compliance with applicable laws regarding the export of crude oil to Canada. As a result, we subsequently submitted additional information to the BIS in October 2003 and May 2004. In August 2004, we received a request from the BIS for additional information. We have responded to this and subsequent requests, and continue to cooperate fully with BIS officials. At this time, we have received neither a warning letter nor a charging letter, which could involve the imposition of penalties, and no indication of what penalties the BIS might assess. As a result, we cannot reasonably estimate the ultimate impact of this matter.

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

Pipeline Releases. In December 2004 and January 2005, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains Pipeline, the U.S. Environmental Protection Agency, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 4,200 barrels and 980 barrels were recovered from the two respective sites. The unrecovered oil has been or will be removed or otherwise addressed by PAA in the course of site remediation. Aggregate costs associated with each release, including estimated remediation costs, are estimated at approximately $1.7 million and $1.4 million, respectively. We continue to work with the appropriate state and federal environmental authorities in responding to the releases and no enforcement proceedings have been instituted by any governmental authority at this time.

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

Environmental. We may experience future releases of crude oil into the environment from our pipeline, gathering and storage operations, or discover past releases that were previously unidentified. Although we maintain an inspection program designed to prevent and, as applicable, to detect and address such releases promptly, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. At December 31, 2004, our reserve for environmental liabilities totaled approximately $19.8 million. Approximately $12.7 million of the reserve is related to liabilities assumed as part of the Link acquisition. Although we believe our reserve is adequate, no assurance can be given that any costs incurred in excess of this reserve would not have a material adverse effect on our financial condition, results of operations or cash flows.

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

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

Commitments

Contractual Obligations. In the ordinary course of doing business we purchase crude oil and LPG from third parties under contracts, the majority of which range in term from thirty-day evergreen to three years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between crude oil and LPG purchases and sales and future delivery obligations. The table below includes purchase obligations related to these activities. Where applicable the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to credit worthy entities.

The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of December 31, 2004.

	2005	2006	2007	2008	2009	Thereafter
			(in millions)			
Long-term debt and interest payments[1]	$49.7	$49.7	$49.7	$49.7	$368.0	$799.7
Leases[2]	17.8	14.0	10.9	6.3	5.2	13.7
Capital expenditure obligations	20.6	—	—	—	—	—
Other long-term liabilities[3]	2.8	4.9	3.5	1.6	1.1	3.0
Subtotal	90.9	68.6	64.1	57.6	374.3	816.4
Crude oil and LPG purchases[4]	1,265.7	20.0	2.0	2.0	1.0	—
Total	$1,356.6	$88.6	$66.1	$59.6	$375.3	$816.4

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. While there is an outstanding balance on our revolving credit facility at December 31, 2004 (this amount is included in the amounts above), we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

(2) Leases are primarily for office rent and trucks used in our gathering activities.

(3) Excludes approximately $10.6 million non-current liability related to SFAS 133 which are included in crude oil and LPG purchases.

(4) Amounts are based on estimated volumes and market prices. The actual physical volume purchased and actual settlement prices may vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil marketing, we provide certain suppliers 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, 2004, we had outstanding letters of credit of approximately $98.0 million.

Distributions. We plan to 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. On February 14, 2005, we paid a cash distribution of $0.6125 per unit on all outstanding units. The total distribution paid was approximately $45.0 million, with approximately $41.2 million paid to our common unitholders and approximately $3.8 million paid to our general partner for its general partner ($0.8 million) and incentive distribution interests ($3.0 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. In 2004, we paid $8.3 million in incentive distributions to our general partner. See "Certain Relationships and Related Transactions—Our General Partner."

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 307 of Regulation S-K.

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 segment profit 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. We estimate that a 5,000 barrel per day decline in volumes shipped from these fields would result in a decrease in annual pipeline segment profit of approximately $3.2 million. In addition, any significant production disruption from the Santa Ynez field due to production problems, transportation problems or other reasons could have a material adverse effect on our business.

Our trading policies cannot eliminate all price risks. In addition, any non-compliance with our trading policies could result in significant financial losses.

Generally, it is our policy that we establish a margin for crude oil purchased 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 generally not to acquire and hold crude oil, futures contracts or derivative products for the purpose of speculating on price changes. This policy cannot, however, eliminate all price risks. For example, any event that disrupts our anticipated physical supply of crude oil could expose us to risk of loss resulting from price changes. Moreover, we are exposed to some risks that are not hedged, including certain basis risks and price risks on certain of our inventory, such as pipeline linefill, which must be maintained in order to transport crude oil on our pipelines. In addition, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil. Although this activity is monitored independently by our risk management function, it exposes us to price risks within predefined limits and authorizations.

In addition, our trading operations involve the risk of non-compliance with our trading policies. For example, we discovered in November 1999 that our trading policy was violated by one of our former employees, which resulted in aggregate losses of approximately $181.0 million. We have taken steps within our organization to enhance our processes and procedures to detect 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.

If we do not make acquisitions on economically acceptable terms our future growth may be limited.

Our ability to grow is substantially dependent on our ability to make acquisitions that result in an increase in adjusted operating surplus per unit. If we are unable to make such accretive acquisitions either because (i) we are unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (ii) we are unable to raise financing for such acquisitions on economically acceptable terms or (iii) we are outbid by competitors, our future growth will be limited. In particular, competition for midstream assets and businesses has intensified substantially and as a result such assets and businesses have become more costly. As a result, we may not be able to complete the number or size of acquisitions that we have targeted internally or to continue to grow as quickly as we have historically.

Our acquisition strategy requires access to new capital. Tightened capital markets or other factors which increase our cost of capital could impair our ability to grow.

Our business strategy is substantially dependent on acquiring additional assets or operations. We continuously consider and enter into discussions regarding potential acquisitions. These transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets and operations. Any material acquisition will require access to capital. Any limitations on our access to capital or increase in the cost of that capital could significantly impair our ability to execute our acquisition strategy. Our ability to maintain our targeted credit profile, including maintaining our credit ratings, could impact our cost of capital as well as our ability to execute our acquisition strategy.

Our acquisition strategy involves risks that may adversely affect our business.

Any acquisition involves potential risks, including:

- performance from the acquired assets and businesses that is below the forecasts we used in evaluating the acquisition;
- a significant increase in our indebtedness and working capital requirements;
- the inability to timely and effectively integrate the operations of recently acquired businesses or assets;
- the incurrence of substantial unforeseen environmental and other liabilities arising out of the acquired businesses or assets, including liabilities arising from the operation of the acquired businesses or assets prior to our acquisition;
- customer or key employee loss from the acquired businesses; and
- the diversion of management's attention from other business concerns.

Any of these factors could adversely affect our ability to achieve anticipated levels of cash flows from our acquisitions, realize other anticipated benefits and our ability to pay distributions or meet our debt service requirements.

The nature of our assets and business could expose us to significant compliance costs and liabilities.

Our operations involving the storage, treatment, processing, and transportation of liquid hydrocarbons including crude oil are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment, otherwise relating to protection of the environment, operational safety and related matters. Compliance with these laws and regulations increases our overall cost of business, including our capital costs to construct, maintain and upgrade equipment and facilities, or claims for damages to property or persons resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial liabilities, and the issuance of injunctions that may restrict or prohibit our operations or even claims of damages to property or persons resulting from our operations. The laws and regulations applicable to our operations are subject to change, and we cannot provide any assurance that compliance with current and future laws and regulations will not have a material effect on our results of operations or earnings. A discharge of hazardous liquids into the environment could, to the extent such event is not insured, subject us to substantial expense, including both the cost to comply with applicable laws and regulations and liability to private parties for personal injury or property damage.

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

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, we estimate that an average 20,000 barrel per day variance in the Basin Pipeline System within the current operating window, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.8 million. In addition, we estimate that an average 10,000 barrel per day variance on the Capline Pipeline System, equivalent to an approximate 7% volume variance on that system, would change annualized segment profit by approximately $1.5 million.

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 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. 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.

We face intense competition in our gathering, marketing, terminalling and storage 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. We estimate that a $0.01 variance in the average segment profit per barrel would have an approximate $2.6 million annual effect on segment profit.

The profitability of our gathering and marketing activities is generally dependent 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 15,000 barrel per day decrease in barrels gathered by us would have an approximate $3.0 million per year negative impact on segment profit. 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.

There can be no assurance that we have adequately assessed the credit worthiness of our existing or future counterparties or that there will not be an unanticipated deterioration in their credit worthiness, which could have an adverse impact on us.

In those cases in which 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 pipeline assets are subject to federal, state and provincial regulation.

Our domestic interstate common carrier pipelines are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Interstate Commerce Act. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be just and reasonable and non-discriminatory. We are also subject to the Pipeline Safety Regulations of the U.S. Department of Transportation. Our intrastate pipeline transportation activities are subject to various state laws and regulations as well as orders of regulatory bodies.

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 Canadian 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.

Fluctuations in demand can negatively affect our operating results.

Fluctuations in demand for crude oil, such as caused by refinery downtime or shutdown, can have a negative effect on our operating results. Specifically, reduced demand in an area serviced by our transmission systems will negatively affect the throughput on such systems. Although the negative impact may be mitigated or overcome by our ability to capture differentials created by demand fluctuations, this ability is dependent on location and grade of crude oil, and thus is unpredictable.

The terms of our indebtedness may limit our ability to borrow additional funds or capitalize on business opportunities.

As of December 31, 2004, our total outstanding long-term debt was approximately $949 million. Various limitations in our indebtedness may reduce our ability to incur additional debt, to engage in some transactions and to capitalize on business opportunities. Any subsequent refinancing of our current indebtedness or any new indebtedness could have similar or greater restrictions.

Changes in currency exchange rates could adversely affect our operating results.

Because we conduct operations in Canada, we are exposed to currency fluctuations and exchange rate risks that may adversely affect our results of operations.

Cash distributions are not guaranteed and may fluctuate with our performance and the establishment of financial reserves.

Because distributions on the common units are dependent on the amount of cash we generate, distributions may fluctuate based on our performance. The actual amount of cash that is available to be distributed each quarter will depend on numerous factors, some of which are beyond our control and the control of the general partner. Cash distributions are dependent primarily on cash flow, including cash flow from financial reserves and working capital borrowings, and not solely on profitability, which is affected by non-cash items. Therefore, cash distributions might be made during periods when we record losses and might not be made during periods when we record profits.

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 our ability to make cash distributions to our unitholders or pay our debt service obligations.

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 could materially and adversely affect our ability to make cash distributions to our unitholders or 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. Imposition of such forms of taxation would reduce the cash available for distribution to unitholders and for payment of debt service obligations. 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 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 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 and sales of these commodities. The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX and over-the-counter transactions, including crude oil swap and option contracts entered into with financial institutions and other energy companies. 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 segment profit we receive. Except for the controlled trading program discussed below, 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.

While we seek to maintain a position that is substantially balanced within our crude oil lease purchase and LPG activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil.

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 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 exception of the controlled trading 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. This accounting treatment is discussed further under Note 2 "Summary of Significant Accounting Policies" of our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2004 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	$42.3	$(11.8)
Swaps and options contracts	(5.1)	(5.1)
LPG:		
Swaps and option contracts	2.3	(2.7)

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 exposures to the cash market; none of these offsetting physical exposures 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. Therefore, from time to time we utilize interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. There are no interest rate hedging instruments outstanding as of December 31, 2004. 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, 2004. All of our senior notes are fixed rate notes and their interest rates are not subject to market risk. Our variable rate debt bears interest at LIBOR, prime or the bankers acceptance rate plus the applicable margin. The average interest rates presented below are based upon rates in effect at December 31, 2004. The carrying values of the variable rate instruments in our credit facilities approximate fair value primarily because interest rates fluctuate with prevailing market rates, and the credit spread on outstanding borrowings reflects market.

	Expected Year of Maturity						
	2005	2006	2007	2008	2009	Thereafter	Total
				(in millions)			
Liabilities:							
Short-term debt—variable rate	$168.6	$—	$—	$—	$—	$—	$168.6
Average interest rate	3.4%	—	—	—	—	—	3.4%
Long-term debt—variable rate	$—	$—	$—	$—	$143.6	$—	$143.6
Average interest rate	—	—	—	—	3.5%	—	3.5%

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.

Because a significant portion 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 and cross currency swaps. Neither the forward exchange contracts nor the cross currency swaps qualify for hedge accounting in accordance with SFAS 133.

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

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

In addition, at December 31, 2004, we also had cross currency swap contracts for an aggregate notional principal amount of $21.0 million effectively converting this amount of our U.S. dollar denominated debt to $32.5 million of Canadian dollar debt (based on Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount reduces by $2.0 million U.S. in May 2005 and has a final maturity in May 2006 ($19.0 million U.S.). At December 31, 2004, $9.9 million of our long-term debt was denominated in Canadian dollars ($11.9 million Canadian based on a Canadian dollar to U.S. dollar exchange rate of 1.20 to 1). All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

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				
	2005	2006	2007	2008	Total
Forward exchange contracts	$(0.9)	$(0.6)	$—	$—	$(1.5)
Cross currency swaps	(0.9)	(5.4)	—	—	(6.3)
Total	$(1.8)	$(6.0)	$—	$—	$(7.8)

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

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

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

None.

Item 9A. ***Controls and Procedures***

We maintain written "disclosure controls and procedures," which we refer to as our "DCP." The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in time to allow for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of December 31, 2004, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

In addition to the information concerning our DCP, we are required to disclose certain changes in our internal control over financial reporting. Although we have made various enhancements to our controls during preparation for our assertion on internal control over financial reporting, there was no change in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. §1350 are furnished with this report as Exhibits 32.1 and 32.2.

Management is responsible for establishing and maintaining adequate internal control over financial reporting. "Internal control over financial reporting" is a process designed by, or under the supervision of, our Chief Executive Officer and our Chief Financial Officer, and effected by our Board of Directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Our management, including our Chief Executive Officer and our Chief Financial Officer, has evaluated the effectiveness of our internal control over financial reporting as of December 31, 2004. See Management's Report on Internal Control Over Financial Reporting on page F-2.

Item 9B. ***Other Information***

None.