## PART II

**Item 5.** ***Market For the Registrant's Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities***

Our common units are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "PAA." On February 17, 2006, the closing market price for our common units was $44.40 per unit and there were approximately 49,000 record holders and beneficial owners (held in street name). As of February 17, 2006, there were 73,768,576 common units outstanding.

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

| | Common Unit Price Range | | Cash |
|---|---|---|---|
| | **High** | **Low** | **Distributions[1]** |
| **2005** | | | |
| 1st Quarter | $40.98 | $36.50 | $0.6375 |
| 2nd Quarter | 45.08 | 38.00 | 0.6500 |
| 3rd Quarter | 48.20 | 42.01 | 0.6750 |
| 4th Quarter | 42.82 | 38.51 | 0.6875 |
| **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 for a quarter are declared and paid in the following calendar quarter.

Our common units are used as a form of compensation to our employees, both in the form of grants of options and phantom units. Additional information regarding our equity compensation plans is included in Part III of this report under Item 11. "Executive Compensation" and Item 13. "Certain Relationships and Related Transactions."

### *Cash Distribution Policy*

We will distribute to our unitholders, on a quarterly basis, all of our available cash in the manner described below. 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 $15.0 million to the general partner in incentive distributions in 2005. On February 14, 2006, we paid a quarterly distribution of $0.6875 per unit applicable to the fourth quarter of 2005. 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."

### *Issuer Purchases of Equity Securities*

We did not repurchase any of our common units during the fourth quarter of fiscal 2005.

## Item 6. *Selected Financial and Operating Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2005, 2004, 2003, 2002, and 2001 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, | | | | |
|---|---|---|---|---|---|
| | **2005** | **2004** | **2003** | **2002** | **2001** |
| | (in millions, except per unit data) | | | | |
| **Statement of operations data:** | | | | | |
| Total Revenues[1] | $ 31,177.3 | $ 20,975.5 | $ 12,589.9 | $ 8,384.2 | $ 6,868.2 |
| Crude oil and LPG purchases and related costs[1] | (29,691.9) | (19,870.9) | (11,746.4) | (7,741.2) | (6,348.3) |
| Pipeline margin activities purchases[1] | (750.6) | (553.7) | (486.1) | (362.3) | (270.8) |
| Field Operating costs (excluding LTIP charge) | (269.4) | (218.6) | (134.2) | (106.4) | (106.8) |
| LTIP charge-operations[2] | (3.1) | (0.9) | (5.7) | — | — |
| General and administrative expenses (excluding LTIP charge) | (80.2) | (75.7) | (50.0) | (45.7) | (46.6) |
| LTIP charge-general and administrative[2] | (23.0) | (7.0) | (23.1) | — | — |
| Depreciation and amortization | (83.5) | (68.7) | (46.2) | (34.0) | (23.3) |
| Total costs and expenses | (30,901.7) | (20,795.5) | (12,491.7) | (8,289.6) | (6,795.8) |
| Operating income | 275.6 | 180.0 | 98.2 | 94.6 | 72.4 |
| Equity earnings in PAA/Vulcan Gas Storage, LLC | 1.0 | — | — | — | — |
| Interest expense | (59.4) | (46.7) | (35.2) | (29.1) | (29.1) |
| Interest and other income (expense),net | 0.6 | (0.2) | (3.6) | (0.2) | 0.4 |
| Income before cumulative effect of change in accounting principle[3] | $ 217.8 | $ 133.1 | $ 59.4 | $ 65.3 | $ 43.7 |
| Basic Net Income per limited partner unit before cumulative effect of change in accounting principle[3] | $ 2.77 | $ 1.94 | $ 1.01 | $ 1.34 | $ 1.12 |
| Diluted Net Income per limited partner unit before cumulative effect of change in accounting principle[3] | $ 2.72 | $ 1.94 | $ 1.00 | $ 1.34 | $ 1.12 |
| Basic weighted average number of limited partner units outstanding | 69.3 | 63.3 | 52.7 | 45.5 | 37.5 |
| Diluted weighted average number of limited partner units outstanding | 70.5 | 63.3 | 53.4 | 45.5 | 37.5 |
| **Balance sheet data (at end of period):** | | | | | |
| Total assets | $ 4,120.3 | $ 3,160.4 | $ 2,095.6 | $ 1,666.6 | $ 1,261.2 |
| Total long-term debt[4] | 951.7 | 949.0 | 519.0 | 509.7 | 354.7 |
| Total debt | 1,330.1 | 1,124.5 | 646.3 | 609.0 | 456.2 |
| Partners' capital | 1,330.7 | 1,070.2 | 746.7 | 511.6 | 402.8 |

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2005 | 2004 | 2003 | 2002 | 2001 |
| | (in millions, except per unit data and volumes) | | | | |
| **Other data:** | | | | | |
| Maintenance capital expenditures | $ 14.0 | $ 11.3 | $ 7.6 | $ 6.0 | $ 3.4 |
| Net cash provided by (used in) operating activities[5] | 24.1 | 104.0 | 115.3 | 185.0 | (16.2) |
| Net cash provided by (used in) investing activities[5] | (297.2) | (651.2) | (272.1) | (374.9) | (263.2) |
| Net cash provided by (used in) financing activities | 270.6 | 554.5 | 157.2 | 189.5 | 279.5 |
| Distributions per limited partner unit[6] [7] | 2.58 | 2.30 | 2.19 | 2.11 | 1.95 |
| **Operating Data:** | | | | | |
| Volumes (thousands of barrels per day)[8] | | | | | |
| Pipeline segment: | | | | | |
| Tariff activities | | | | | |
| All American | 51 | 54 | 59 | 65 | 69 |
| Basin | 290 | 265 | 263 | 93 | N/A |
| Capline | 132 | 123 | N/A | N/A | N/A |
| Cushing to Broome | 66 | N/A | N/A | N/A | N/A |
| North Dakota/Trenton | 77 | 39 | N/A | N/A | N/A |
| West Texas/New Mexico Area Systems[9] | 428 | 338 | 189 | 104 | N/A |
| Canada | 255 | 263 | 203 | 187 | 132 |
| Other | 426 | 330 | 110 | 115 | 144 |
| Pipeline margin activities | 74 | 74 | 78 | 73 | 61 |
| Total | 1,799 | 1,486 | 902 | 637 | 406 |
| Gathering, marketing, terminalling and storage segment: | | | | | |
| Crude oil lease gathering | 610 | 589 | 437 | 410 | 348 |
| LPG sales | 56 | 48 | 38 | 35 | 19 |

(1) Includes buy/sell transactions. See Note 2 to our Consolidated Financial Statements.

(2) Compensation expense related to our 1998 Long-Term Incentive Plan (“1998 LTIP”) and our 2005 Long-Term Incentive Plan (“2005 LTIP”). See Item 11. “Executive Compensation—Long-Term Incentive Plans.”

(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 and $38.4 million for 2003, 2002 and 2001, 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) and $0.97 ($0.97 diluted) for 2003, 2002 and 2001 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 2003 and prior years 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 year.

(7) 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 5 to our Consolidated Financial Statements.

(8) 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 year.

(9) The aggregate of multiple systems in the West Texas/New Mexico area.

## 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 and Internal Growth Projects
- 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

### Executive Summary

#### *Company Overview*

We are engaged in interstate and intrastate crude oil transportation, and crude oil gathering, marketing, terminalling and storage, as well as the marketing and storage of liquefied petroleum gas and other natural gas related petroleum products. We have an extensive network of pipeline transportation, terminalling, storage and gathering assets in key oil producing basins, transportation corridors and at major market hubs in the United States and Canada. In addition, through our 50% equity ownership in PAA/Vulcan, we are engaged in the development and operation of natural gas storage facilities. We were formed in September 1998, and our operations are conducted directly and indirectly through our primary operating subsidiaries, Plains Marketing, L.P., Plains Pipeline, L.P. and Plains Marketing Canada, L.P.

We are one of the largest midstream crude oil companies in North America. As of December 31, 2005, we owned approximately 15,000 miles of active crude oil pipelines, approximately 39 million barrels of active terminalling and storage capacity and approximately 500 transport trucks. Currently, we handle an average of over 3.0 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 transportation operations ("Pipeline") 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, Capital Spending and Significant Activities*

During 2005, we recognized net income of $217.8 million and earnings per diluted limited partner unit of $2.72, compared to $130.0 million and $1.89, respectively during 2004. Both 2005 and 2004 were substantial increases over 2003. The results for 2005 as compared to the two previous years were significantly impacted by increased segment profit in both of our operating segments. Key items impacting 2005 include:

- Favorable market conditions characterized by relatively strong contango market conditions and significantly high volatility in price and market structure of crude oil.
- Increased contributions to both of our operating segments attributable to a full year of operation of businesses acquired in 2004 and the realization of synergies from those businesses.

- The inclusion in 2005 of an aggregate charge of approximately $26.1 million related to our Long-Term Incentive Plans. See "—Critical Accounting Policies and Estimates—Long-Term Incentive Plan Accruals."
- A loss of approximately $18.9 million in 2005 resulting from the mark-to-market of open derivative instruments pursuant to Statement of Financial Accounting Standard No. 133, as amended ("SFAS 133").
- The impact of Hurricanes Katrina and Rita. Our estimates indicate that the negative effect of these hurricanes was approximately $8-10 million (including approximately $3.7 million of operating costs, net of estimated insurance reimbursements). This includes disruptions to our operations and uninsured damage to some of our terminals and other facilities. On an overall basis, the hurricanes did not have a material impact on our revenue-generating capacity.
- We continued to develop internal growth projects to optimize and expand our presence in our operating areas, while continuing to pursue strategic and accretive acquisitions. These activities totaled $304.4 million in 2005 and included the formation of a joint venture (PAA/Vulcan) that made an acquisition of natural gas storage facilities. See "—Acquisitions and Internal Growth Projects."
- In addition, we maintained the relative strength of our overall capital structure and increased liquidity through a series of equity issuances and senior notes issuances. We also expanded and extended the size and maturity of our credit facilities. See "—Liquidity and Capital Resources."

***Prospects for the Future***

We believe that our terminalling and storage activities and our gathering and marketing activities are counter-cyclical. We believe that this balance of activities, combined with our pipeline transportation operations, generally provides us with the flexibility to maintain a base level of margin irrespective of whether a strong or weak market exists and, in certain circumstances, to realize incremental margin during volatile market conditions.

During 2005, we strengthened our business by expanding our asset base through acquisitions and internal growth projects. In 2006, we intend to spend approximately $230 million on internal growth projects and also to continue to develop our inventory of projects for implementation beyond 2006. We believe the outlook is positive for, and have a strategic initiative of increasing our participation in, the importation 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, our recent entry into the natural gas storage business is consistent with our stated strategy of leveraging our assets, business model, knowledge and expertise into businesses that are complementary to our existing activities. We will continue to look for ways to grow the natural gas storage business and continue to evaluate opportunities in other complementary midstream business activities. 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 midstream infrastructure.

Although we believe that we are well situated in the North American midstream infrastructure, we face various operational, regulatory and financial challenges that may impact our ability to execute our strategy as planned. In addition, we operate in a mature industry and believe that acquisitions will play an important role in our potential growth. We will continue to pursue the purchase of midstream crude oil assets, and we will also continue to initiate expansion projects designed to optimize crude oil flows in the areas in which we operate. However, we can give no assurance that our current or future acquisition or expansion efforts will be successful. See Item 1A. "Risk Factors—Risks Related to Our Business."

**Acquisitions and Internal Growth Projects**

We completed a number of acquisitions and capital expansion projects in 2005, 2004 and 2003 that have impacted our results of operations and liquidity discussed herein. The following table summarizes our capital expenditures for the periods indicated (in millions):

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Acquisition capital[(1)] | $ 40.3 | $563.9 | $183.8 |
| Investment in PAA/Vulcan Gas Storage, LLC | 112.5 | — | — |
| Internal growth projects | 148.8 | 117.3 | 55.5 |
| Maintenance capital | 14.0 | 11.3 | 7.6 |
| Total | $315.6 | $692.5 | $246.9 |

(1) Acquisition capital includes deposits in the year the acquisition closed, rather than the year the deposit was paid. Deposits paid were approximately $12 million for the Shell Gulf Coast Pipeline Systems acquisition in 2004 and approximately $16 million for the Capline acquisition in 2003.

***Internal Growth Projects***

During 2004 and 2005 we increased our focus on expansion and internal growth opportunities. We increased our annual level of spending on these projects over 100% in 2004 from 2003 and increased an additional 25% in 2005 over the amount spent in 2004. The following table summarizes our 2005 and 2004 projects (in millions):

| Projects | 2005 | 2004 |
|---|---|---|
| Trenton pipeline expansion | $ 31.8 | $ 11.8 |
| St. James terminal | 15.2 | — |
| Cushing to Broome pipeline | 8.2 | 39.2 |
| Northwest Alberta fractionator | 15.6 | — |
| Cushing Phase IV and V expansions | 11.2 | 9.4 |
| Link acquisition asset upgrades | 9.3 | 4.8 |
| Kerrobert tank expansion | 4.3 | — |
| Other expansion projects | 53.2 | 52.1 |
| Total internal growth projects | $148.8 | $117.3 |

Our 2005 projects included the construction and expansion of pipeline systems, crude oil storage facilities and the construction of a natural gas liquids fractionator. With the exception of the Cushing to Broome Pipeline and the Trenton Pipeline expansion, the 2005 revenue contribution associated with the 2005 projects discussed above were minimal, but we expect revenue contribution to increase in 2006 and further increase in 2007. We expect to continue our focus on internal growth projects during 2006. See "—Liquidity and Capital Resources—2006 Capital Expansion Projects."

***Acquisitions***

The following acquisitions were accounted for, and the purchase prices were allocated, in accordance with SFAS 141, "Business Combinations," unless otherwise noted. See Note 3 to our Consolidated Financial Statements for additional information about our acquisition activities. The majority of our acquisitions were initially financed with borrowings under our credit facilities, which were subsequently repaid with portions of the proceeds from equity issuances and the issuance of senior notes. The businesses acquired impacted our results of operations commencing on the effective date of each acquisition as indicated in the tables below. Our ongoing acquisitions and capital expansion activities are discussed further in "—Liquidity and Capital Resources."

***2005 Acquisitions***

We completed six small transactions in 2005 for aggregate consideration of approximately $40.3 million. The transactions included crude oil trucking operations and several crude oil pipeline systems along the Gulf Coast as well as in Canada. We also acquired an LPG pipeline and terminal in Oklahoma. These acquisitions did not materially impact our results of operations, either individually or in the aggregate.The following table summarizes our acquisitions that were completed in 2005 (in millions):

| Acquisition | Effective Date | Acquisition Price | Operating Segment |
|---|---|---|---|
| Shell Gulf Coast Pipeline Systems[(1)] | 1/1/2005 | $ 12.0 | Pipeline |
| Tulsa LPG Pipeline | 3/2/2005 | 10.0 | GMT&S |
| Other acquisitions | Various | 18.3 | Pipeline/GMT&S |
| Total | | $ 40.3 | |

(1) A $12 million deposit for the Shell Gulf Coast Pipeline Systems acquisition was paid into escrow in December 2004.

In addition, in September 2005, PAA/Vulcan acquired Energy Center Investments LLC ("ECI"), an indirect subsidiary of Sempra Energy, for approximately $250 million. ECI develops and operates underground natural gas storage facilities. We own 50% of PAA/Vulcan and the remaining 50% is owned by a subsidiary of Vulcan Capital. We made a $112.5 million capital contribution to PAA/Vulcan and we account for the investment in PAA/Vulcan under the equity method in accordance with Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock."

***2004 Acquisitions***

In 2004, we completed several acquisitions for aggregate consideration of approximately $563.9 million. The Link and Capline acquisitions were material to our operations. See Note 3 to our Consolidated Financial Statements. The following table summarizes our acquisitions that were completed in 2004, and a description of our material acquisitions follows the table (in millions):

| Acquisition | Effective Date | Acquisition Price | Operating Segment |
|---|---|---|---|
| Capline and Capwood Pipeline Systems ("Capline acquisition")[(1)] | 03/01/04 | $ 158.5 | Pipeline |
| Link Energy LLC ("Link acquisition") | 04/01/04 | 332.3 | Pipeline/ GMT&S |
| Cal Ven Pipeline System | 05/01/04 | 19.0 | Pipeline |
| Schaefferstown Propane Storage Facility[(2)] | 08/25/04 | 46.4 | GMT&S |
| Other | various | 7.7 | GMT&S |
| Total | | $ 563.9 | |

(1) Includes a deposit of approximately $16 million which was paid in December 2003 for the Capline acquisition.

(2) Includes approximately $14.4 million of LPG operating inventory acquired.

*Capline and Capwood Pipeline Systems.* The principal assets acquired 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. 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.

*Link Energy LLC.* The Link crude oil business we acquired consisted 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.

*2003 Acquisitions*

During 2003, we completed ten acquisitions for aggregate consideration of approximately $183.8 million (including an accrual for the deferred purchase price of a 2001 acquisition). The aggregate consideration includes cash paid, estimated transaction costs, assumed liabilities and estimated near-term capital costs. These acquisitions did not materially impact our results of operations, either individually or in the aggregate. The following table summarizes our acquisitions that were completed in 2003 (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 |
| South Louisiana Assets | 06/01/03 | 13.4 | Pipeline/ GMT&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 |
| CANPET acquisition deferred purchase price[1] | 12/31/03 | 24.3 | GMT&S |
| Other acquisitions | various | 15.8 | Pipeline/ GMT&S |
| Total | | $183.8 | |

(1) In connection with the CANPET acquisition in 2001, a portion of the purchase price was deferred subject to various performance criteria. These objectives were met as of December 31, 2003.

## Critical Accounting Policies and Estimates

### *Critical Accounting Policies*

We have adopted various accounting policies to prepare our consolidated financial statements in accordance with generally accepted accounting principles in the United States. These critical accounting policies are discussed in Note 2 to the Consolidated Financial Statements.

### *Critical Accounting Estimates*

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

*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 6.5% 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 mark-to-market derivatives 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 and governmental penalties, 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 environmental 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 $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.

*Long-Term Incentive Plan (“LTIP”) Accruals.* We also make accruals for potential payments under our 2005 LTIP and 1998 LTIP plans when we determine that vesting of the common units granted under these plans is probable. The aggregate amount of the actual charge to expense will be determined by the unit price on the date vesting occurs (or, in some cases, the average unit price for a range of dates) multiplied by the number of units, plus our share of associated employment taxes. Uncertainties involved in this accrual include whether or not we actually achieve the specified performance requirements, the actual unit price at time of settlement and the continued employment of personnel subject to the vestings. We have concluded that it is probable that we will achieve a $3.00 annualized distribution rate and therefore have accelerated the recognition of compensation expense related to the portion of the awards that vest up to that rate. Under generally accepted accounting principles, we are required to recognize expense when it is considered probable that phantom unit grants under the LTIP plans will vest. As a result, we recognized total compensation expense of approximately $26.1 million in 2005 and $7.9 million in 2004 related to the awards granted under our 1998 LTIP and our 2005 LTIP plans. A change in our unit price of $1 from the amount we used to record our accrual would have an impact of approximately $2.2 million on our operating income. We cannot provide assurance that actual amounts will not vary significantly from estimated amounts. See Note 9 to our Consolidated Financial Statements.

## Recent Accounting Pronouncements and Change in Accounting Principle

### *Recent Accounting Pronouncements*

For a discussion of recent accounting pronouncements that will impact us, see Note 2 to our Consolidated Financial Statements.

### *Change in Accounting Principle*

Effective January 1, 2004, we changed our method of accounting for pipeline linefill in third party assets. Previously, we had viewed pipeline linefill, whether in our assets or third party assets, as having long-term characteristics rather than characteristics typically associated with the short-term classification of operating inventory. Therefore, previously we did not include linefill barrels in the same average costing calculation as our operating inventory, but instead carried linefill at historical cost. Following this change in accounting principle, the linefill in third party assets that we historically classified as a portion of “Pipeline Linefill” on the face of the balance sheet (a long-term asset) and carried at historical cost, is included in “Inventory” (a current asset) in determining the average cost of operating inventory and applying the lower of cost or market analysis. At the end of each period, we reclassify the linefill in third party assets not expected to be liquidated within the succeeding twelve months out of “Inventory” (a current asset), at average cost, and into “Inventory in Third Party Assets” (a long-term asset), which is now reflected as a separate line item 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 year ended December 31, 2003 is detailed below:

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

## Results of Operations

### *Analysis of Operating Segments*

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

We evaluate segment performance based on segment profit and maintenance capital. We define segment profit as revenues less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative ("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 mitigate the actual decline in the value of our principal fixed assets. These maintenance costs are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining "available cash," consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life or expand the operating capacity are charged to expense as incurred. See Note 13 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

### *Pipeline Operations*

As of December 31, 2005, 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 segment for the periods indicated:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| | | (in millions) | |
| **Operating Results**[1] | | | |
| Revenues | | | |
| Tariff activities | $ 357.6 | $ 299.7 | $ 153.3 |
| Pipeline margin activities[2] | 772.7 | 575.2 | 505.3 |
| Total pipeline operations revenues | 1,130.3 | 874.9 | 658.6 |
| Costs and Expenses | | | |
| Pipeline margin activities purchases[3] | (751.5) | (554.6) | (487.1) |
| Field operating costs (excluding LTIP charge) | (152.4) | (121.1) | (60.9) |
| LTIP charge—operations | (1.0) | (0.1) | (1.4) |
| Segment G&A expenses (excluding LTIP charge)[4] | (39.6) | (38.1) | (18.3) |
| LTIP charge—general and administrative[4] | (10.6) | (3.8) | (9.6) |
| Segment profit | $ 175.2 | $ 157.2 | $ 81.3 |
| Maintenance capital | $ 8.4 | $ 8.3 | $ 6.4 |
| **Average Daily Volumes** (thousands of barrels per day)[5] | | | |
| Tariff activities | | | |
| All American | 51 | 54 | 59 |
| Basin | 290 | 265 | 263 |
| Capline | 132 | 123 | N/A |
| Cushing to Broome | 66 | N/A | N/A |
| North Dakota/Trenton | 77 | 39 | N/A |
| West Texas/New Mexico Area Systems[6] | 428 | 338 | 189 |
| Canada | 255 | 263 | 203 |
| Other | 426 | 330 | 110 |
| Total tariff activities | 1,725 | 1,412 | 824 |
| Pipeline margin activities | 74 | 74 | 78 |
| Total | 1,799 | 1,486 | 902 |

(1) Revenues and purchases include intersegment amounts.

(2) Pipeline margin activities includes revenues associated with buy/sell arrangements of $197.1 million, $149.8 million and $166.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 16,000, 12,000 and 17,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, respectively. See Note 2 to our Consolidated Financial Statements.

(3) Pipeline margin activities purchases includes purchases associated with buy/sell arrangements of $196.2 million $142.5 million and $159.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 16,000, 12,000 and 17,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, respectively. See Note 2 to our Consolidated Financial Statements.

(4) 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 year.

(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.

(6) The aggregate of multiple systems in the West Texas/New Mexico area.

Total revenues for our pipeline segment have increased over the three-year period ended December 31, 2005. The revenue increase in 2005 relates both to our tariff activities and to our margin activities. The increase in revenues from tariff activities in the 2004 period is primarily related to increased volumes resulting from our acquisition activities as discussed further below. The increase in revenues from our margin activities in 2005 and 2004 is related to higher average prices for crude oil sold and transported on our San Joaquin Valley gathering system in each of the years compared to the prior year. The increase in 2005 was also favorably impacted by an increase in buy/sell volumes as compared to the applicable prior year. 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.

Segment profit, our primary measure of segment performance, was impacted by the following:

- Increased volumes and related tariff revenues—The increase in volumes and related tariff revenues during 2005 primarily relates to the Link acquisition and other acquisitions completed during 2005 and 2004. This increase primarily resulted from the inclusion of the related assets for the entire 2005 period versus only a portion of the 2004 period. 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.

- Increased revenues from our loss allowance oil—As is common in the industry, our crude oil tariffs incorporate a “loss allowance factor” intended to offset losses due to evaporation, measurement and other losses in transit. The loss allowance factor averages approximately 0.2% by volume. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Gains or losses on sales of allowance oil barrels are also included in tariff revenues. Revenues related to loss allowance oil increased during 2005 as compared to 2004 and 2003 because of increased volumes and higher crude oil prices. The average NYMEX crude oil price for 2005 was $56.65 per barrel versus $41.29 per barrel in 2004 and $31.08 per barrel in 2003.

- Increased field operating costs—Our continued growth, primarily from the Link acquisition and other acquisitions completed during 2004, is the principal cause of the $32.2 million increase in field operating costs to $153.4 million (including the LTIP charge) in 2005 and also the cause for increases in costs in 2004. The increased costs primarily relate to (i) payroll and benefits, (ii) emergency response and environmental remediation of pipeline releases, (iii) maintenance and (iv) utilities.

- Increased segment G&A expenses—Segment G&A expenses excluding LTIP charges were relatively flat in 2005 compared to 2004. However, expense related to our LTIP increased $6.8 million in the 2005 period as compared to the 2004 period. 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 also increased in 2004 compared to 2003 because of increased headcount from our growth and higher costs related to compliance activities attributable to Sarbanes-Oxley section 404 compliance. These items were partially offset by the inclusion of an LTIP charge of approximately $3.8 million in 2004 compared to $9.6 million in the 2003.

As discussed above, the increase in pipeline segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2005, 2004 and 2003 that have impacted our results of operations. The following table summarizes the impact of recent acquisitions and expansions on volumes and revenues related to our tariff activities:

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2005 | | 2004 | | 2003 | |
| | Revenues | Volumes | Revenues | Volumes | Revenues | Volumes |
| | (volumes in thousands of barrels per day and revenues in millions) | | | | | |
| **Tariff activities**[(1)(2)(3)] | | | | | | |
| 2005 acquisitions/expansions. . . | $ 14.1 | 96 | $ N/A | N/A | $ N/A | N/A |
| 2004 acquisitions/expansions. . . | 138.2 | 665 | 115.6 | 525 | N/A | N/A |
| 2003 acquisitions/expansions. . . | 52.7 | 187 | 39.7 | 170 | 14.8 | 82 |
| All other pipeline systems . . . . . | 152.6 | 777 | 144.4 | 717 | 138.5 | 742 |
| **Total tariff activities**. . . . . . . . . | $357.6 | 1,725 | $299.7 | 1,412 | $153.3 | 824 |

(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 year.

(3) To the extent there has been an expansion to one of our existing pipeline systems, any incremental revenues and volumes are included in the category for the period that the pipeline was acquired. For new pipeline systems that we construct, incremental revenues and volumes are included in the period the system became operational.

In 2005, average daily volumes from our tariff activities increased by approximately 22% to approximately 1.7 million barrels per day, and revenues from our tariff activities increased by approximately 19% to approximately $357.6 million. The increase is attributable to:

- Pipeline systems acquired or brought into service during 2005, which contributed approximately 96,000 barrels per day and $14.1 million of revenues during 2005. Approximately 66,000 barrels per day and $7.2 million of revenues are attributable to our recently constructed Cushing to Broome pipeline system.

- Volumes and revenues from pipeline systems acquired in 2004 increased in 2005 as compared to 2004, reflecting the following:

  —An increase in 2005 as compared to 2004 of 118,000 barrels per day and $15.8 million of revenues from the pipelines acquired in the Link acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period. The 2005 period also includes (i) increased revenues from our loss allowance oil resulting from higher crude oil prices and (ii) increased revenues from the Trenton pipeline system resulting from our expansion activities on that system. These increases were partially offset by the impact of a reduction in tariff rates that were voluntarily lowered to encourage third party shippers. Pipeline segment profit was reduced by approximately $12.0 million because of these market rate adjustments. As a result of these lower tariffs on barrels shipped by us in connection with our gathering and marketing activities, segment profit from GMT&S was increased by a comparable amount,

  —An increase of 17,000 barrels per day and $4.4 million of revenues in 2005 as compared to 2004 from the pipelines acquired in the Capline acquisition, reflecting the inclusion of these systems for the entire 2005 period as compared to only a portion of the 2004 period, and

  —An increase of 5,000 barrels per day and $2.4 million of revenues in 2005 as compared to 2004 from other businesses acquired in 2004.

- Volumes and revenues from pipeline systems acquired in 2003 increased in 2005 as compared to 2004, reflecting the following:

  —An increase in 2005 as compared to 2004 of 5,000 barrels per day and $5.2 million of revenues from the pipelines acquired in the 2003 Red River acquisition, reflecting increased tariff rates on the system, partially related to the quality of crude oil shipped,

  —An increase of $3.0 million of revenues related to higher realized prices on our loss allowance oil, and

—An increase of 12,000 barrels per day and $4.8 million of revenues in 2005 compared to 2004 from other businesses acquired in 2003, primarily related to higher volumes.

- Revenues from all other pipeline systems also increased in 2005, along with a slight increase in volumes. The increase in revenues is related to several items including:

  —The appreciation of Canadian currency (the Canadian to U.S. dollar exchange rate appreciated to an average of 1.21 to 1 for 2005 compared to an average of 1.30 to 1 in 2004), and

  —Volume increases on certain of our systems, partially related to a shift of certain minor pipeline systems from our GMT&S segment.

Average daily volumes from our tariff activities increased to approximately 1.4 million barrels per day in 2004 compared to 2003, while revenues increased to $299.7 million. The increase primarily relates to volumes and revenues from pipeline systems acquired in 2004, reflecting the following:

- The inclusion of an average of 283,000 barrels per day and $79.3 million in revenues from the pipelines acquired in the Link acquisition,
- The inclusion of an average of approximately 123,000 barrels per day and $25.9 million of revenues from the Capline pipeline system, and
- 119,000 barrels per day and $10.4 million of revenues from other 2004 acquisitions.

Several other factors impacted the increase in 2004 to a lesser extent:

- 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, coupled with higher realized prices on our loss allowance oil,
- Revenues from all other pipeline systems increased in 2004, primarily related to slightly higher volumes on various systems, and
- The appreciation of Canadian currency (the Canadian 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 in the year ended December 31, 2003).

*Maintenance Capital*

For the periods ended December 31, 2005, 2004 and 2003, maintenance capital expenditures for our pipeline segment were approximately $8.4 million, $8.3 million and $6.4 million, respectively.

***Gathering, Marketing, Terminalling and Storage Operations***

As of December 31, 2005, we owned approximately 39 million barrels of active above-ground crude oil terminalling and storage facilities, including a crude oil terminalling and storage facility at Cushing, Oklahoma. The Cushing Interchange is one of the largest crude oil market hubs in the United States and the designated delivery point for 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 15 million barrels of our 39 million barrels of tankage is used primarily in our GMT&S segment and the balance is used in our Pipeline 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 thus 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 resulting from high demand) provide an offset to this reduced cash flow. In addition, we supplement the counter-cyclical balance of our asset base with derivative hedging activities. We believe that this combination of our terminalling and storage activities, gathering and marketing activities and our hedging activities provides a counter-cyclical balance that has a stabilizing effect on our results of operations and cash flows. We also believe that this balance enables us to protect against downside risk while at the same time providing us with upside opportunities in volatile market conditions.

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. As an example of the potential lack of correlation between changes in revenues and changes in segment profit, our revenues increased approximately 50% in 2005 compared to 2004, while our segment profit more than doubled in the same period. These increases in segment profit are discussed further below. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with increases or decreases in lease gathered volumes and LPG sales volumes. However, certain market conditions create opportunities that may significantly impact segment profit. 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.

Revenues from our GMT&S operations were approximately $30.2 billion, $20.2 billion and $12.0 billion for the years ended December 31, 2005, 2004 and 2003, respectively. The increase in revenues for 2005 as compared to 2004 and 2003 was primarily because of higher crude oil prices. The average NYMEX price for crude oil was $56.65, $41.29 and $31.08 per barrel for the years ended December 31, 2005, 2004 and 2003, respectively.

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 GMT&S segment for the comparative periods indicated:

| | December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| | (in millions, except per barrel amounts) | | |
| **Operating Results**[1] | | | |
| Revenues[2] [3] | $ 30,186.6 | $ 20,223.5 | $ 11,985.6 |
| Purchases and related costs[4][5] | (29,830.6) | (19,992.8) | (11,799.8) |
| Field operating costs (excluding LTIP charge) | (117.0) | (97.5) | (73.3) |
| LTIP charge—operations | (2.1) | (0.8) | (4.3) |
| Segment G&A expenses (excluding LTIP charge)[6] | (40.6) | (37.7) | (31.6) |
| LTIP charge—general and administrative[6] | (12.4) | (3.2) | (13.5) |
| Segment profit[3] | $ 183.9 | $ 91.5 | $ 63.1 |
| SFAS 133 mark-to-market adjustment[3] | $ (18.9) | $ 1.0 | $ 0.4 |
| Maintenance capital | $ 5.6 | $ 3.0 | $ 1.2 |
| Segment profit per barrel[7] | $ 0.77 | $ 0.39 | $ 0.36 |
| **Average Daily Volumes** | | | |
| (thousands of barrels per day)[8] | | | |
| Crude oil lease gathering | 610 | 589 | 437 |
| LPG sales | 56 | 48 | 38 |

(1) Revenues and purchases and related costs include intersegment amounts.

(2) Includes revenues associated with buy/sell arrangements of $16,077.8 million, $11,247.0 million and $6,124.9 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 744,000, 790,000 and 545,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, respectively. The previously referenced amounts include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

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

(4) Includes purchases associated with buy/sell arrangements of $15,910.3 million, $11,137.7 million and $5,967.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. Volumes associated with these arrangements were approximately 744,000, 790,000 and 545,000 barrels per day for the years ended December 31, 2005, 2004 and 2003, respectively. The previously referenced amounts include certain estimates based on management's judgment; such estimates are not expected to have a material impact on the balances. See Note 2 to our Consolidated Financial Statements.

(5) Purchases and related costs include interest expense on contango inventory purchases of $23.7 million, $2.0 million and $1.0 million for the years ended December 31, 2005, 2004 and 2003, respectively.

(6) 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 year.

(7) Calculated based on crude oil lease gathered volumes and LPG sales volumes.

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

Segment profit in 2005 increased significantly over 2004. The increase was primarily related to very favorable market conditions and successful execution of risk management strategies coupled with increased volumes and synergies realized from businesses acquired in the last two years.

The primary factors affecting current period results were:

- Favorable market conditions—These favorable market conditions include a shift in the market structure from a backwardated market with a price differential of as much as $1.14 per barrel in late 2004 to a prolonged and pronounced contango market with a price differential of as much as $1.91 in 2005. The contango market averaged approximately $0.48, $1.22, $0.69 and $0.46 in each quarter of 2005, respectively. Although we are normally adversely impacted by the initial transition from a backwardated market to a contango market, the market remained in contango throughout much of 2005 and we have been able to adjust our purchases at the wellhead to both maintain our margins and remain competitive in the gathering and marketing business. In addition, we have been able to use a portion of our tankage in our terminalling and storage business to capture a significant level of profits from contango-related strategies. The volatile market allowed us to utilize our hedging activities to optimize and enhance the margins of both our gathering and marketing assets and our terminalling and storage assets at different times during the year. Increased receipts of foreign crude oil movements at our facilities also positively impacted our results.

- Increased tankage used in our GMT&S operations—The positive impact of the favorable market conditions discussed above was further enhanced by the increase in the average amount of tankage used in our GMT&S operations to approximately 13.3 million barrels during 2005 as compared to an average of 12.7 million barrels in 2004.
- Decreased transportation costs—Lower tariffs on barrels shipped by us on certain pipelines acquired in the Link acquisition reduced purchases and related costs by approximately $12.0 million for the year ended December 31, 2005. Segment profit for our Pipeline segment was decreased by a comparable amount.
- Increased field operating costs—The increased costs primarily related to payroll and benefits and to higher fuel costs. These increases are the result of our growth, primarily from acquisitions, and higher fuel prices during 2005 as compared to 2004.

We recognized a mark-to-market adjustment of $18.9 million net loss in 2005 pursuant to SFAS 133 compared to a net gain of $1.0 million in the 2004. The $18.9 million adjustment was largely attributable to U.S. commodities. The primary components of the adjustment included:

- A decrease in the mark-to-market of approximately $19.9 million resulting from the change in fair value for option and futures contracts that serve to mitigate risk associated with our lease gathering and tankage business exposures. Although these derivatives do not qualify for hedge accounting, their purpose is to mitigate risk associated with our physical assets in our storage and terminalling activities and contractual arrangements in our lease gathering activities. A portion of the decrease in fair value during the current period relates to the settlement of mark-to-market gains from the previous period. Total settlements related to these strategies during 2005 were revenues of $19.4 million. The $19.9 million further breaks down as follows:

  —The amount of the decrease in the mark-to-market fair value for option contracts was approximately $7.4 million. Because our option activity often involves option sales, these do not receive hedge accounting treatment. Some of the fluctuations in value for those option contracts are due to time to expiry and volatility in the marketplace. Because these strategies are executed with a long-term risk management goal and the intent to take delivery and utilize the tankage assets to store physical commodity if so needed, the impact on forward positions due to these fluctuations is not indicative of true anticipated economic results.

  —The amount of the decrease in the mark-to-market fair value for futures contracts was approximately $12.5 million. The majority of this decrease was due to reduced backwardation during that time frame. In general, revenue from storing crude oil is reduced in a backwardated market (when oil prices for future deliveries are lower than for current deliveries) as there is less incentive to store crude oil from month-to-month. We enter into derivative contracts that will offset the reduction in revenue by generating offsetting gains in a backwardated market structure. Because the tankage arrangements will not necessarily result in physical delivery, they are not eligible for hedge accounting treatment under SFAS 133. A reduction in backwardation results in forward losses in our risk management strategies offset by stronger storage revenues. However, owning the assets and having the ability to take delivery allows us to limit exposures to the cost of storage.

- An increase in the mark-to-market of $1.1 million primarily related to the change in fair value of certain derivative instruments used to minimize the risk of unfavorable changes in exchange rates. A portion of the increase in fair value during the current period relates to the settlement of mark-to-market losses from the previous period. Total settlements related to these derivatives during 2005 were $0.7 million.

Segment profit per barrel (calculated based on our lease gathered crude oil and LPG volumes) was $0.77, $0.39 and $0.36 per barrel for the years ended December 31, 2005, 2004 and 2003, respectively. As discussed above, our current period results were strongly impacted by favorable market conditions. We are not able to predict with any reasonable level of accuracy whether market conditions will remain as favorable as we have recently experienced, and operating results may not be indicative of sustainable performance.

*Maintenance capital*

For the periods ended December 31, 2005, 2004 and 2003, maintenance capital expenditures were approximately $5.6 million, $3.0 million, and $1.2 million, respectively, for our gathering, marketing, terminalling and storage operations segment. The year over year increases are related to our growth.

***Other Income and Expenses***

*Depreciation and Amortization*

Depreciation and amortization expense was $83.5 million for the year ended December 31, 2005, compared to $68.7 million and $46.2 million for the years ended December 31, 2004 and 2003, respectively. The increase in 2005 relates primarily to (i) an increased amount of depreciable assets resulting from our acquisition activities and capital projects, (ii) accelerated depreciation and amortization for tanks that we plan to take out of service by 2009, and (iii) a non-cash loss related to sales of assets. 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 and an impairment charge of approximately $2.0 million associated with taking our pipeline system in the Illinois Basin out of service. Amortization of debt issue costs was $2.8 million in 2005, $2.5 million in 2004, and $3.8 million in 2003.

*Interest Expense*

Interest expense was $59.4 million for the year ended December 31, 2005, compared to $46.7 million and $35.2 million for the years ended December 31, 2004 and 2003, respectively. Interest expense is primarily impacted by:

- our average debt balances;
- the level and maturity of fixed rate debt and interest rates associated therewith; and
- market interest rates and our interest rate hedging activities on floating rate debt.

The following table summarizes selected components of our average debt balances:

| | For the year ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| | (in millions) | | |
| Fixed rate senior notes[1] | $ 891 | $586 | $214 |
| Borrowings under our revolving credit facilities[2] | 135 | 274 | 311 |
| Total | $1,026 | $860 | $525 |

(1) Weighted average face amount of senior notes, exclusive of discounts.

(2) Excludes borrowings under our senior secured hedged inventory facility and other contango inventory-related borrowings.

During 2005, we issued $150 million of 10-year senior unsecured notes. 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 2005 to approximately 87% as compared to approximately 68% in 2004 and 41% in 2003. During 2005, 2004 and 2003, the average three month LIBOR rate was 3.6%, 1.6%, and 1.2%, respectively. The overall higher average debt balances in 2005 and 2004 were primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.6% in 2005, compared to 5.0% and 6.0% in 2004 and 2003, respectively. The net impact of the items discussed above was an increase in interest expense in 2005 of approximately $12.7 million to a total of $59.4 million.

The higher average debt balance in 2004 as compared to 2003 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.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our GMT&S segment profit as we consider interest on these borrowings a direct cost to storing the inventory. These borrowings are primarily under our senior secured hedged inventory facility. These costs were approximately $23.7 million, $2.0 million and $1.0 million for the year ended December 31, 2005, 2004 and 2003, respectively.

**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 regarding potential acquisitions by us of transportation, gathering, terminalling or storage assets and related midstream businesses. These acquisition efforts often involve assets which, if acquired, could 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 midstream businesses outside of the scope of our current operations, but with respect to which these resources effectively can be applied. We are presently engaged in discussions and negotiations with various parties regarding the acquisition of assets and businesses described above, but 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.

*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 additional assets.

The DOT is currently considering expanding the scope of its pipeline regulation to include certain gathering pipeline systems that are not currently subject to regulation. This expanded scope could include the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact this will have on our operating expenses. However, we cannot assure you that future costs related to the potential programs will not be material.

During 2006, we are expanding an internal review process started in 2004 in which we are reviewing various aspects of our pipeline and gathering systems that are not subject to the DOT pipeline integrity management rule. The purpose of this process is to review the surrounding environment, condition and operating history of these pipelines and gathering assets to determine if such assets warrant additional investment or replacement. Accordingly, we may be required (as a result of additional DOT regulation) or we may elect (as a result of our own initiatives) to spend substantial sums to ensure the integrity of and upgrade our pipeline systems to maintain environmental compliance and, in some cases, we may take pipelines out of service if we believe the cost of upgrades will exceed the value of the pipelines. We cannot provide any assurance as to the ultimate amount or timing of future pipeline integrity expenditures for environmental compliance.

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

- Continued overall depletion of U.S. crude oil production.
- The continuing convergence of worldwide crude oil supply and demand trends.
- Aggressive practices in the U.S. to maintain working crude oil inventory levels below historical levels despite rising demand in North America.

- Industry compliance with the DOT's adoption of API 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.
- 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, which were evident in 2005. 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.

We are also regularly evaluating midstream businesses that are complementary to our existing businesses and that possess attractive long-term growth prospects. Through PAA/Vulcan's acquisition of ECI in 2005, the Partnership entered the natural gas storage business. Although our investment in natural gas storage assets is currently relatively small when considering the Partnership's overall size, we intend to grow this portion of our business through future acquisitions and expansion projects. We believe that strategically located natural gas storage facilities will become increasingly important in supporting the reliability of gas service needs in the United States. Rising demand for natural gas is outpacing domestic natural gas production, creating an increased need for imported natural gas. A continuation of this trend will result in increased natural gas imports from Canada and the Gulf of Mexico, and LNG imports. We believe our business strategy and expertise in hydrocarbon storage will allow us to grow our natural gas storage platform and benefit from these trends.

**Liquidity and Capital Resources**

The Partnership has a defined financial growth strategy that states how we intend to finance our growth and sets forth targeted credit metrics. We have also established a targeted credit rating. See Items 1 and 2. "Business and Properties—Financial Strategy.''

Cash generated from operations and our credit facilities are our primary sources of liquidity. At December 31, 2005, we had working capital of approximately $11.9 million, approximately $789.1 million of availability under our committed revolving credit facilities and approximately $580.7 million of availability 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.

***Cash generated from operations***

The primary drivers of cash generated from our 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 in which 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 in which we pay for and store the crude oil and the subsequent period in which we receive proceeds from the sale of the crude oil. When we store the crude oil, we borrow under our credit facilities to pay for the crude oil so the impact on operating cash flow is negative. Conversely, cash flow from operating activities increases during the period in which we collect the cash from the sale of the stored crude oil. Similarly, the level of LPG inventory stored at period end affects our cash flow from operating activities.

Our cash flow from operations was $24.1 million in 2005 and reflects cash generated by our recurring operations offset primarily by an increase in inventory of approximately $412  millionoffset by a net decrease in other components of working capital. The net decrease is primarily related to changes in accounts receivable and payables related to the purchase and sale of crude oil and NYMEX margin deposits.

Cash flow from operating activities 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 flow from operations was also negatively impacted by a decrease of approximately $20 million in prepayments received from counterparties to mitigate credit risk. Our positive cash flow from operating activities 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 counterparties 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.

***Cash provided by equity and debt financing activities***

We periodically access the capital markets for both equity and debt financing. We have filed with the Securities and Exchange Commission a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue from time to time up to an aggregate of $2 billion of debt or equity securities. At December 31, 2005, we have approximately $1.8 billion of unissued securities remaining available under this registration statement.

Cash provided by financing activities was $270.6 million, $554.5 million and $157.2 million for each of the last three years, respectively. Our financing activities primarily relate to funding (i) acquisitions, (ii) internal capital projects and (iii) short-term working capital and hedged inventory borrowings related to our contango market activities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings under our credit facilities.

*Equity Offerings.* During the last three years we completed several equity offerings as summarized in the table below. Certain of these offerings involved related parties. See Note 8 to our Consolidated Financial Statements:

| 2005 | | 2004 | | 2003 | |
|---|---|---|---|---|---|
| Units | Net Proceeds[1] | Units | Net Proceeds[1] | Units | Net Proceeds[1] |
| | | (in millions, except units) | | | |
| 5,854,000 | $241.9 | 4,968,000 | $160.9 | 2,840,800 | $ 88.4 |
| 575,000 | 22.3 | 3,245,700 | 100.9 | 3,250,000 | 98.0 |
| | $264.2 | | $261.8 | 2,645,000 | 63.9 |
| | | | | | $250.3 |

(1) Includes our general partner's proportionate capital contribution and is net of costs associated with the offering.

*Senior Notes and Credit Facilities.* During the three years ended December 31, 2005 we completed the sale of senior unsecured notes as summarized in the table below.

| Year | Description | Face Value | Net Proceeds[1] |
|---|---|---|---|
| | | (in millions) | |
| 2005......... | 5.25% Senior Notes issued at 99.5% of face value | $150 | $149.3 |
| 2004......... | 4.75% Senior Notes issued at 99.6% of face value | $175 | $174.2 |
| | 5.88% Senior Notes issued at 99.3% of face value | $175 | $173.9 |
| 2003......... | 5.625% Senior notes isued at 99.7% of face value | $250 | $249.3 |

(1) Face value of notes less the applicable discount.

During the year ended December 31, 2005, we had net working capital and short-term letter of credit and hedged inventory borrowings of approximately $206.1 million. These borrowings are used primarily for purchases of crude oil inventory that was stored. See "—Cash generated from operations." During 2005, we also had net repayments on our long-term revolving credit facility of approximately $143.7 million resulting from cash generated from our operations and other financing activities. During 2004, we had net borrowings under our long-term and short-term revolving credit facilities of approximately $107.7 million and during 2003 we had net repayments of $215.4 million. For further discussion related to our credit facilities and long-term debt, see "—Credit Facilities and Long-term Debt."

### *Capital Expenditures and Distributions Paid to Unitholders and General Partners*

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 and the financing activities discussed above. Our primary uses of cash are for our acquisition activities, capital expenditures for internal growth projects and distributions paid to our unitholders and general partners. See "—Acquisitions and Internal Growth Projects." The price of the acquisitions includes cash paid, transaction costs and assumed liabilities and net working capital items. Because of the non-cash items included in the total price of the acquisition and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year.

*2006 Capital Expansion Projects.* We expect to invest approximately $230 million on internal growth projects during 2006. We also expect maintenance capital costs to be approximately $23 million. Our 2006 projects include the following projects with the estimated cost for the entire year (in millions):

| Projects | 2006 |
|---|---|
| St. James, Louisiana storage facility | $ 60 |
| Spraberry System expansion | 20 |
| High Prairie truck and rail terminals | 31 |
| Kerrobert tankage and pumps | 35 |
| Midale truck terminal | 11 |
| Truck trailers | 11 |
| Wichita Falls tankage | 9 |
| Other Projects | 53 |
| Subtotal | 230 |
| Maintenance capital | 23 |
| Total | $253 |

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.

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

| | Distributions Paid | | | | | |
|---|---|---|---|---|---|---|
| | Common | Subordinated | GP | | | Distribution |
| Year | Units | Units(1) | Incentive | 2% | Total | per LP unit |
| 2005 | $178.4 | $ — | $15.0 | $3.6 | $197.0 | $2.58 |
| 2004 | $142.9 | $ 4.2 | $ 8.3 | $3.0 | $158.4 | $2.30 |
| 2003 | $ 92.7 | $21.9 | $ 4.9 | $2.3 | $121.8 | $2.19 |

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

### *Credit Facilities and Long-term Debt*

In November 2005, we amended our senior unsecured credit facility to increase the aggregate capacity to $1 billion and the sub-facility for Canadian borrowings to $400 million. The amended facility can be expanded to $1.5 billion, subject to additional lender commitments, and has a final maturity of November 2010. Additionally, in the second quarter of 2005, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $425 million to $800 million. In November 2005, we extended the maturity of the senior secured hedged inventory facility to November 2006.

We also have five issues of senior debt outstanding that total $950 million, excluding premium or discount, and range in size from $150 million to $250 million and mature at various dates through 2016. The $950 million senior debt includes $150 million principal long-term debt issued in 2005, which matures in 2015. See Note 4 to our Consolidated Financial Statements.

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; and
- sell substantially all of our assets or enter into a merger or consolidation.

Our credit facility treats a change of control as an event of default and also requires us to maintain a debt coverage ratio that 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***

See Note 10 to our Consolidated Financial Statements.

***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 creditworthy 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, 2005.

| | Total | 2006 | 2007 | 2008 (in millions) | 2009 | 2010 | 2011 and Thereafter |
|---|---|---|---|---|---|---|---|
| Long-term debt and interest payments[(1)] | $1,384.7 | $ 57.0 | $ 57.0 | $ 57.0 | $228.7 | $47.7 | $937.3 |
| Leases[(2)] | 114.0 | 19.8 | 16.7 | 12.4 | 11.5 | 9.6 | 44.0 |
| Capital expenditure obligations | 5.0 | 5.0 | — | — | — | — | — |
| Other long-term liabilities[(3)] | 42.7 | 4.5 | 30.5 | 2.2 | 0.6 | 0.2 | 4.7 |
| Subtotal | 1,546.4 | 86.3 | 104.2 | 71.6 | 240.8 | 57.5 | 986.0 |
| Crude oil and LPG purchases[(4)] | 2,790.6 | 2,065.7 | 575.1 | 138.2 | 3.9 | 2.2 | 5.5 |
| Total | $4,337.0 | $2,152.0 | $679.3 | $209.8 | $244.7 | $59.7 | $991.5 |

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at December 31, 2005 (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 $6.5 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 periods of up to seventy days and are terminated upon completion of each transaction. At December 31, 2005, we had outstanding letters of credit of approximately $55.5 million.

*Capital Contributions to PAA/Vulcan Gas Storage, LLC.* We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund (i) certain projects specified at the time PAA/Vulcan acquired ECI and (ii) unspecified future capital needs up to an aggregate of $20 million. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for 50% of the cost. For any other project (or a project in which Vulcan Gas Storage declines to exercise its right to participate), we have the right to make additional capital contributions to fund 100% of the project. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage's interest. If at any time our interest in PAA/Vulcan exceeds 70%, Vulcan Gas Storage would have the right, but not the obligation, to make capital contributions proportionate to its ownership interest at the time. See Note 8 to our Consolidated Financial Statements.

*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 in the discretion of our general partner for future requirements. On February 14, 2006, we paid a cash distribution of $0.6875 per unit on all outstanding units. The total distribution paid was approximately $57.3 million, with approximately $50.7 million paid to our common unitholders and approximately $6.6 million paid to our general partner for its general partner interest ($1.0 million) and incentive distribution interest ($5.6 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 2005, we paid $14.9 million in incentive distributions to our general partner. See Item 13. "Certain Relationships and Related Transactions—Our General Partner."

## Off-Balance Sheet Arrangements

We have invested in an entity, PAA/Vulcan Gas Storage, LLC, which is not consolidated in our financial statements. In conjunction with this investment, from time to time we may elect to provide financial and performance guarantees or other forms of credit support. See Note 8 to our Consolidated Financial Statements for more information concerning our obligations as they relate to this investment.

## 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 and, in certain circumstances, to realize incremental margin during volatile market conditions. 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. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, IPE 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. Our risk management function also approves all new risk management strategies through a formal process. With the exception of the controlled trading program discussed below, our approved strategies are intended to mitigate enterprise level risks that are inherent in our core businesses of gathering and marketing and storage. 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, IPE 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, as these activities could expose us to significant losses.

Although 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.

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 to our Consolidated Financial Statements.

All of our open commodity price risk derivatives at December 31, 2005 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:

| | Fair Value | Effect of 10% Price Decrease |
|---|---|---|
| | (in millions) | |
| Crude oil: | | |
| Futures contracts | $(16.0) | $(41.5) |
| Swaps and options contracts | $(17.5) | $(16.8) |
| LPG: | | |
| Swaps and options contracts | $ 10.2 | $ 8.8 |

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 used in these estimates as well as the source for the estimates 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 use 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 use interest rate swaps and collars to hedge interest obligations on specific debt issuances, including anticipated debt issuances. We had no interest rate hedging instruments outstanding as of December 31, 2005. 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, 2005. 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, 2005. 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 | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2006 | 2007 | 2008 | 2009 | 2010 | Thereafter | Total |
| | (dollars in millions) | | | | | | |
| Liabilities: | | | | | | | |
| Short-term debt—variable rate | $374.7 | $— | $— | $— | $— | $— | $374.7 |
| Average interest rate | 4.9% | — | — | — | — | — | 4.9% |
| Long-term debt—variable rate | $ — | $— | $— | $— | $— | $— | $ — |
| Average interest rate | — | — | — | — | — | — | — |

*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, 2005, we had forward exchange contracts that allow us to exchange $2.0 million Canadian dollars for $1.5 million U.S. dollars, quarterly (based on a Canadian dollar to U.S. dollar exchange rate of 1.32 to 1).

In addition, at December 31, 2005, we also had cross currency swap contracts for an aggregate notional principal amount of $19.0 million, effectively converting this amount of our U.S. dollar denominated debt to $29.4 million of Canadian dollar debt (based on a Canadian dollar to U.S. dollar exchange rate of 1.55 to 1). The notional principal amount has a final maturity in May 2006 of $19.0 million U.S. At December 31, 2005, none of our long-term debt was denominated in Canadian dollars. All of these financial instruments are placed with what we believe to be large, creditworthy financial institutions.

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 | | | | | |
|---|---|---|---|---|---|---|
| | **2006** | **2007** | **2008** | **2009** | **2010** | **Total** |
| Forward exchange contracts | $(0.8) | $— | $— | $— | $— | $(0.8) |
| Cross currency swaps | (6.4) | — | — | — | — | (6.4) |
| Total | $(7.2) | $— | $— | $— | $— | $(7.2) |

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

See "Index to the Consolidated Financial Statements" on page F-1.

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

Not applicable.

**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, 2005, 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, 2005. See Management's Report on Internal Control Over Financial Reporting on page F-2.

### Item 9B. *Other Information*

There was no information required to be disclosed in a report on Form 8-K during the fourth quarter of 2005 that has not previously been reported.