PART II

Item 5. *Market For 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 20, 2007, the closing market price for our common units was $54.67 per unit and there were approximately 70,000 record holders and beneficial owners (held in street name). As of February 20, 2007, there were 109,405,178 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	
2006			
1st Quarter	$ 47.00	$ 39.81	$ 0.7075
2nd Quarter	48.92	42.81	0.7250
3rd Quarter	47.35	43.21	0.7500
4th Quarter	53.23	45.20	0.8000
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

(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. Additional information regarding our equity compensation plans is included in Part III of this report under Item 13. “Certain Relationships and Related Transactions, and Director Independence.”

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 and except for the agreed upon adjustment discussed below, 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.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts due it as incentive distributions. The reduction will be effective for five years, as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. The total reduction in incentive distributions will be $65 million. The first quarterly reduction took place in connection with the distribution paid in February 2007.

We paid $33.1 million to the general partner in incentive distributions in 2006. On February 14, 2007, we paid a quarterly distribution of $0.80 per unit applicable to the fourth quarter of 2006. See Item 13. “Certain Relationships and Related Transactions, and Director Independence — 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 2006.

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Selected Financial Data

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2006, 2005, 2004, 2003 and 2002 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,				
	2006	2005	2004	2003	2002
Statement of operations data:					
Total Revenues(1)	$ 22,444.4	$ 31,176.5	$ 20,975.0	$ 12,589.7	$ 8,383.8
Crude oil and LPG purchases and related costs(1)	(20,819.7)	(29,691.9)	(19,870.9)	(11,746.4)	(7,741.2)
Pipeline margin activities purchases(1)	(665.9)	(750.6)	(553.7)	(486.1)	(362.3)
Field operating costs	(369.8)	(272.5)	(219.5)	(139.9)	(106.4)
General and administrative expenses	(133.9)	(103.2)	(82.7)	(73.1)	(45.7)
Depreciation and amortization	(100.4)	(83.5)	(68.7)	(46.2)	(34.0)
Total costs and expenses	(22,089.7)	(30,901.7)	(20,795.5)	(12,491.7)	(8,289.6)
Operating income	354.7	274.8	179.5	98.0	94.2
Interest expense	(85.6)	(59.4)	(46.7)	(35.2)	(29.1)
Equity earnings in unconsolidated entities	7.7	1.8	0.5	0.2	0.4
Interest and other income (expense), net	2.3	0.6	(0.2)	(3.6)	(0.2)
Income tax expense	(0.3)	—	—	—	—
Income before cumulative effect of change in accounting principle(2)	$ 278.8	$ 217.8	$ 133.1	$ 59.4	$ 65.3
Basic net income before cumulative effect of change in accounting principle(2)	$ 2.84	$ 2.77	$ 1.94	$ 1.01	$ 1.34
Diluted net income before cumulative effect of change in accounting principle(2)	$ 2.81	$ 2.72	$ 1.94	$ 1.00	$ 1.34
Basic weighted average number of limited partner units outstanding	81.1	69.3	63.3	52.7	45.5
Diluted weighted average number of limited partner units outstanding	81.9	70.5	63.3	53.4	45.5
Balance sheet data (at end of period):					
Total assets	$ 8,714.9	$ 4,120.3	$ 3,160.4	$ 2,095.6	$ 1,666.6
Total long-term debt(3)	2,626.3	951.7	949.0	519.0	509.7
Total debt	3,627.5	1,330.1	1,124.5	646.3	609.0
Partners’ capital	2,976.8	1,330.7	1,070.2	746.7	511.6
Other data:					
Maintenance capital expenditures	$ 28.2	$ 14.0	$ 11.3	$ 7.6	$ 6.0
Net cash provided by (used in) operating activities(4)	(275.3)	24.1	104.0	115.3	185.0
Net cash (used in) investing activities(4)	(1,651.0)	(297.2)	(651.2)	(272.1)	(374.9)
Net cash provided by financing activities	1,927.0	270.6	554.5	157.2	189.5
Declared distributions per limited partner unit(5)(6)	2.87	2.58	2.30	2.19	2.11
Volumes (thousands of barrels per day)(7)					
Transportation segment:					
Tariff activities	2,018	1,725	1,412	824	564

Pipeline margin activities	88	74	74	78	73
Total	2,106	1,799	1,486	902	637

	Year Ended December 31,				
	2006	2005	2004	2003	2002
Facilities Segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	20.7	16.8	14.8	12.0	3.8
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	4.3	—	—	—
LPG processing (thousands of barrels per day)	12.2	—	—	—	—
Total (average monthly capacity in millions of barrels)(8)	23.2	17.5	14.8	12.1	3.9
Marketing segment:					
Crude oil lease gathering	650	610	589	437	410
LPG sales	70	56	48	38	35
Waterborne foreign crude imported	63	59	12	N/A	N/A
Total	783	725	649	475	445

(1) Includes buy/sell transactions for all periods prior to the second quarter of 2006. See Note 2 to our Consolidated Financial Statements.

(2) Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2006 change in our method of accounting for unit-based payment transactions would have been $224.1 million, $136.3 million, $65.7 million, and $71.6 million for 2005, 2004, 2003 and 2002, respectively. In addition, basic net income per limited partner unit before cumulative effect of change in accounting principle would have been $2.81 ($2.76 diluted), $1.98 ($1.98 diluted), $1.13 ($1.12 diluted) and $1.47 ($1.47 diluted) for 2005, 2004, 2003 and 2002, respectively. Income from continuing operations before cumulative effect of change in accounting principle pro forma for the impact of the January 1, 2004 change in our method of accounting for pipeline linefill in third-party assets would have been $61.4 million and $64.8 million for 2003 and 2002, 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) and $1.33 ($1.33 diluted) for 2003 and 2002, respectively.

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

(4) 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.

(5) Distributions represent those declared and paid in the applicable year.

(6) 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.

(7) 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.

(8) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly volumes in millions.

Management's Discussion and Analysis of Financial Condition and Results of Operations

Item 7.

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 the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products (liquefied petroleum gas and other natural gas related petroleum products are collectively referred to as "LPG"). In addition, through our 50% equity ownership in PAA/Vulcan, we develop and operate natural gas storage facilities. We were formed in September 1998, and our operations are conducted directly and indirectly through our operating subsidiaries.

Prior to the fourth quarter of 2006, we managed our operations through two segments. Due to our growth, especially in the facilities portion of our business (most notably in conjunction with the Pacific acquisition), we have revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. As a result, we now manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines and gathering systems. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity, transportation fees, barrel exchanges and buy/sell arrangements. Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Our marketing segment operations generally consist of merchant activities associated primarily with the purchase and sale of crude oil and LPG. Our marketing activities are designed to produce a stable baseline of results in a variety of market conditions, while at the same time providing upside exposure to opportunities inherent in volatile market conditions. These activities utilize storage facilities at major interchange and terminalling locations and various hedging strategies to reduce the negative impact of market volatility and provide counter-cyclical balance.

Overview of Operating Results, Capital Spending and Significant Activities

During 2006, we recognized net income of $285.1 million and earnings per diluted limited partner unit of $2.88, compared to net income of $217.8 million and earnings per diluted limited partner unit of $2.72 during 2005.

Both 2006 and 2005 were substantial increases over 2004. Net income was $130.0 million and earnings per diluted limited partner unit was $1.89 for 2004. Key items impacting 2006 include:

Balance Sheet and Capital Structure

- The completion of the Pacific acquisition for approximately $2.5 billion (including the equity issuance and assumption of debt discussed below), and six other acquisitions for aggregate consideration of approximately $565 million.
- The issuance of 22 million limited partner units (valued at $1.0 billion) in exchange for Pacific limited partner units as part of the Pacific acquisition and the sale of 13.4 million limited partner units for net proceeds of approximately $621 million.
- The assumption of $433 million of senior notes as part of the Pacific acquisition and the issuance of $1,250 million of Senior Notes for net proceeds of approximately $1,243 million.
- Capital expenditures (excluding acquisitions and maintenance capital) of $332 million.
- Limited partner distributions of $224.9 million ($2.87 per limited partner unit) and General Partner distributions of $37.7 million paid during 2006.

Income Statement

- Favorable execution of our risk management strategies in our marketing segment in a pronounced contango market with a high level of overall crude oil volatility.
- Increased volumes and related tariff revenues on our pipeline systems.
- An increase in field operating costs and general and administrative expenses primarily associated with continued growth from acquisitions as well as internal growth projects and an increase of $17 million in 2006 related to our Long-Term Incentive Plans. See "— Critical Accounting Policies and Estimates — Critical Accounting Estimates — Long-Term Incentive Plan Accruals."
- A charge of approximately $4 million in 2006 resulting from the mark-to-market of open derivative instruments pursuant to SFAS 133.
- A gain of approximately $6 million resulting from the reduction of our obligation for outstanding LTIP awards, which was recorded as a cumulative effect of change in accounting principle pursuant to the adoption of SFAS No. 123(R) (revised 2004), "Share-Based Payment."

Prospects for the Future

Access to storage tankage by our marketing segment provides a counter-cyclical balance that has a stabilizing effect on our operations and cash flow associated with this segment. The strategic use of our terminalling and storage assets in conjunction with our gathering and marketing operations generally provides us with the flexibility to maintain a base level of margin irrespective of crude oil market conditions and, in certain circumstances, to realize incremental margin during volatile market conditions.

During 2006, we strengthened our business by expanding our asset base through approximately $3 billion of acquisitions and $332 million of internal growth projects. In 2007, we intend to spend approximately $500 million on internal growth projects and also to continue to develop our inventory of projects for implementation beyond 2007. Several of the larger storage tank projects for 2007, such as the construction or expansion of the Patoka, Cushing and St. James terminals, are well positioned to benefit from the importation of waterborne foreign crude oil into the Gulf Coast as well as the importation of Canadian crude oil. We also believe there are opportunities for us to grow our LPG business. In addition, our 2005 entry into the natural gas storage business and our 2006 entries into the refined products transportation and storage business and the barge transportation business are 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 these businesses and continue to evaluate opportunities in other complementary midstream business activities. Specifically, we intend to apply our business model to the refined products business by establishing and growing a marketing and distribution business to complement our strategically located assets. 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 assets, and we will also continue to initiate expansion projects designed to optimize product 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 2006, 2005 and 2004 that have impacted our results of operations and enabled us to enhance our liquidity, as discussed herein. The following table summarizes our capital expenditures for acquisitions (including equity investments), capital expansion (internal growth projects) and maintenance capital for the periods indicated (in millions):

	December 31,		
	2006	2005	2004
Acquisition capital(1)	$ 3,021.1	$ 40.3	$ 563.9
Investment in PAA/Vulcan Gas Storage, LLC	10.0	112.5	—
Investment in Settoon Towing	33.6	—	—
Internal growth projects	332.0	148.8	117.3
Maintenance capital	28.2	14.0	11.3
	$ 3,424.9	$ 315.6	$ 692.5

(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.

Internal Growth Projects

As a result of capital expansion opportunities originating from prior acquisitions, we increased our annual level of spending on these projects by 123% in 2006 compared to 2005. The following table summarizes our 2006 and 2005 projects (in millions):

Projects	2006	2005
St. James, Louisiana storage facility — Phase I	$ 69.9	$ 15.2
St. James, Louisiana storage facility — Phase II	12.9	—
Trenton pipeline expansion	12.3	31.8
Kerrobert tankage	28.5	4.3
East Texas/Louisiana tankage	12.0	—
Spraberry System expansion	15.4	—
Cushing Phase IV and V expansions	1.1	11.2
Cushing Tankage — Phase VI	10.1	—
Cushing to Broome pipeline	—	8.2
Northwest Alberta fractionator	2.2	15.6
Link acquisition asset upgrades	—	9.3
High Prairie rail terminals	9.1	—
Midale/Regina truck terminal	12.7	—
Truck trailers	9.9	—
Wichita Falls tankage	7.8	—
Basin connection — Oklahoma	6.9	—
Mobile/Ten Mile tankage and metering	4.0	—
Cheyenne Pipeline Construction	10.3	—
Other Projects	106.9	53.2
Total	$ 332.0	$ 148.8

Our 2006 projects included the construction and expansion of pipeline systems and crude oil storage and terminal facilities (notably Cushing and St. James). We expect internal growth capital projects to expand further in 2007. See "— Liquidity and Capital Resources — Capital Expenditures and Distributions Paid to Unitholders and General Partners — 2007 Capital Expansion Projects."

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities 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 table below. Our ongoing acquisitions and capital expansion activities are discussed further in "— Liquidity and Capital Resources." See Note 3 to our Consolidated Financial Statements for additional information about our acquisition activities.

2006 Acquisitions

In 2006, we completed several acquisitions for aggregate consideration of approximately $3.0 billion. The Pacific merger was material to our operations. See Note 3 to our Consolidated Financial Statements. The following table summarizes the acquisitions that were completed in 2006, and a description of our material acquisitions follows the table (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Pacific	11/15/2006	$ 2,455.7	Transportation, Facilities, Marketing
Andrews	4/18/2006	220.1	Transportation Facilities, Marketing
SemCrude	5/1/2006	129.4	Marketing
BOA/CAM/HIPS	7/31/2006	130.2	Transportation
Products Pipeline	9/1/2006	65.6	Transportation
Other	various	20.1	Transportation, Facilities, Marketing
Total		$ 3,021.1	

Pacific. On November 15, 2006 we completed our acquisition of Pacific pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included: (i) the acquisition from LB Pacific of the general partner interest and incentive distribution rights of Pacific as well as approximately 5.2 million Pacific common units and approximately 5.2 million Pacific subordinated units for a total of $700 million and (ii) the acquisition of the balance of Pacific's equity through a unit-for-unit exchange in which each Pacific unitholder (other than LB Pacific) received 0.77 newly issued common units of the Partnership for each Pacific common unit. The total value of the transaction was approximately $2.5 billion, including the assumption of debt and estimated transaction costs. Upon completion of the merger-related transactions, the general partner and limited partner ownership interests in Pacific were extinguished and Pacific was merged with and into the Partnership. The assets acquired in the Pacific acquisition included approximately 4,500 miles of active crude oil pipeline and gathering systems and 550 miles of refined products pipelines, over 13 million barrels of active crude oil storage capacity and 9 million barrels of refined products storage capacity, a fleet of approximately 75 owned or leased trucks and approximately 1.9 million barrels of crude oil and refined products linefill and working inventory. The Pacific assets complement our existing asset base in California, the Rocky Mountains and Canada, with minimal asset overlap but attractive potential vertical integration opportunities. The results of operations and assets and liabilities from the Pacific acquisition have been included in our consolidated financial statements since November 15, 2006. The purchase price allocation related to the Pacific acquisition is preliminary and subject to change. See Note 3 to our Consolidated Financial Statements.

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

Cash payment to LB Pacific	$ 700.0
Value of Plains common units issued in exchange for Pacific common units	1,001.6
Assumption of Pacific debt (at fair value)	723.8
Estimated transaction costs(1)	30.3
Total purchase price	$ 2,455.7

(1) Includes investment banking fees, costs associated with a severance plan in conjunction with the acquisition and various other direct acquisition costs.

Purchase Price Allocation	
Property, plant and equipment, net	$ 1,411.7
Investment in Frontier	8.7
Inventory	32.6
Pipeline linefill and inventory in third party assets	63.6
Intangible assets	72.3
Goodwill(1)	843.2
Assumption of working capital and other long-term assets and liabilities, including $20.0 of cash	23.6
Total purchase price	$ 2,455.7

(1) Represents the preliminary amount in excess of the fair value of the net assets acquired and is associated with our view of the future results of operations of the businesses acquired based on the strategic location of the assets and the growth opportunities that we expect to realize as we integrate these assets into our existing business strategy.

The majority of the acquisition costs associated with the Pacific acquisition was incurred as of December 31, 2006, resulting in total cash paid during 2006 of approximately $723 million.

The following table shows our calculation of the sources of funding for the acquisition (in millions):

Fair value of Plains common units issued in exchange for Pacific common units	$ 1,001.6
Plains general partner capital contribution	21.6
Assumption of Pacific debt (at estimated fair value), net of repayment of Pacific credit facility(1)	433.1
Plains new debt incurred	999.4
Total sources of funding	$ 2,455.7

(1) The assumption of Pacific’s debt and credit facility at fair value was $433.1 million and $290.7 million, respectively. We paid off the credit facility in connection with closing of the transaction.

Other 2006 Acquisitions. During 2006, we completed six additional acquisitions for aggregate consideration of approximately $565 million. These acquisitions included (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the “Andrews acquisition”), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana (SemCrude), (iii) interests in various crude oil pipeline systems in Canada and the U.S. including a 100% interest in the BOA Pipeline, various interests in HIPS and a 64.35% interest in the CAM Pipeline system, and (iv) three refined products pipeline systems.

In addition, in November 2006, we purchased a 50% interest in Settoon Towing for approximately $33 million. Settoon Towing owns and operates a fleet of 57 transport and storage barges as well as 30 transport tugs. Its core business is the gathering and transportation of crude oil and produced water from inland production facilities across the Gulf Coast.

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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	Price	Operating Segment
Shell Gulf Coast Pipeline Systems(1)	1/1/2005	$ 12.0	Transportation
Tulsa LPG Pipeline	3/2/2005	10.0	Marketing
Other acquisitions	Various	18.3	Transportation, Facilities, Marketing
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	Transportation
Link Energy LLC ("Link acquisition")	04/01/04	332.3	Transportation, Facilities, Marketing
Cal Ven Pipeline System	05/01/04	19.0	Transportation
Schaefferstown Propane Storage Facility(2)	08/25/04	46.4	Facilities
Other	various	7.7	Facilities, Marketing
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 58-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.

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. Accordingly, a variance from this estimate of 10% would impact the respective line items by less than 1% on an annual basis. In addition, we estimate that less than 4% of total operating income and less than 5% of total net income are recorded using estimates. 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 annual 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, taxes, 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 $5.2 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. The purchase price allocation related to the Pacific acquisition is preliminary and subject to change. See Note 3 to our Consolidated Financial Statements.

Long-Term Incentive Plan Accruals. We also make accruals to recognize the fair value of our outstanding LTIP awards as compensation expense. Under generally accepted accounting principles, we are required to estimate the fair value of our outstanding LTIP awards and recognize that fair value as compensation expense over the course of the LTIP award's vesting period. For LTIP awards that contain a performance condition, the fair value of the LTIP award is recognized as compensation expense only if the attainment of the performance condition is considered probable. The amount of the actual charge to compensation 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 preceding the vesting date) multiplied by the number of units, plus our share of associated employment taxes. Uncertainties involved in this estimate include the actual unit price at time of settlement, whether or not a performance condition will be attained and the continued employment of personnel subject to the vestings.

We achieved a $3.20 annualized distribution rate and therefore we are accruing compensation expense for LTIP awards that vest upon the attainment of that rate. We recognized total compensation expense of approximately $42.7 million in 2006 and $26.1 million in 2005 related to awards granted under our various LTIP plans. We cannot provide assurance that the actual fair value of our LTIP awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Goodwill. We perform our goodwill impairment test annually (as of June 30) and when events or changes in circumstances indicate that the carrying value may not be recoverable. We consider the estimate of fair value to be a critical accounting estimate because (a) a goodwill impairment could have a material impact on our financial position and results of operations and (b) the estimate is based on a number of highly subjective judgments and assumptions.

Property, Plant and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property, plant and equipment a critical accounting estimate. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of “holding” versus “selling” an asset;
- the forecast of undiscounted expected future cash flow over the asset’s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

Asset Retirement Obligation

We account for asset retirement obligations under SFAS No. 143 “Accounting for Asset Retirement Obligations.” SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (1) the time of the liability recognition, (2) initial measurement of the liability, (3) allocation of asset retirement cost to expense and (4) subsequent measurement of the liability. SFAS 143 requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets, primarily related to our transportation segment, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. The timing of the obligations is determined relative to the date on which the asset is abandoned.

Many of our pipelines are trunk and interstate systems that transport crude oil. The pipelines with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for this transportation will cease and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates. A small portion of our contractual or regulatory obligations are related to assets that are inactive or that we plan to take out of service and although the ultimate timing and costs to settle these obligations are not known with certainty, we can reasonably estimate the obligation.

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.

Changes in Accounting Principle

Stock-Based Compensation

In December 2004, SFAS 123(R) was issued, which amends SFAS No. 123, “Accounting for Stock-Based Compensation,” and establishes accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from such share-based payment transactions be recognized in the financial statements at fair value. Following our general partner’s adoption of Emerging Issues Task Force Issue No. 04-05, “Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights,” we are now part of the same consolidated group and thus SFAS 123(R) is applicable to our general partner’s long-term incentive plan. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a cumulative effect of change in accounting principle of approximately $6 million. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair-value based liability as calculated under a SFAS 123(R) methodology. Our LTIPs are administered by our general partner. We are required to reimburse all costs incurred by our general partner through LTIP settlements. As a result, our LTIP awards are classified as liabilities under SFAS 123(R). Under the modified prospective transition method, we are not required to adjust our prior period financial statements for our LTIP awards.

Linefill

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

This change in accounting principle was effective January 1, 2004 and is reflected as a cumulative change in our consolidated statement of operations for the year ended 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.

Results of Operations

Analysis of Operating Segments

Prior to the fourth quarter of 2006, we managed our operations through two segments. Due to our growth, especially in the facilities portion of our business most notably in conjunction with the Pacific acquisition, we have revised the manner in which we internally evaluate our segment performance and decide how to allocate resources to our segments. As a result, we now manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. Prior period disclosures have been revised to reflect our change in segments.

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 15 to our Consolidated Financial Statements for a reconciliation of segment profit to consolidated income before cumulative effect of change in accounting principle.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the marketing segment secures transportation and facilities services from the Partnership's other two segments as well as third-party service providers under month-to-month and multi-year arrangements. Inter-segment transportation service rates are based on posted tariffs for pipeline transportation services. Facilities segment services are also obtained at rates consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our marketing segment to reflect the fact that these services may be canceled on short notice to enable the facilities segment to provide services to third parties. We believe that the estimates with respect to the rates that are charged by our facilities segment to our marketing segment are reasonable. We also allocate certain operating expense and general and administrative overheads between segments. We believe that the estimates with respect to the allocations are reasonable.

Transportation

As of December 31, 2006, we owned approximately 20,000 miles of active gathering and mainline crude oil and refined products pipelines located throughout the United States and Canada as well as approximately 60 million barrels of active above-ground crude oil, refined products and LPG storage tanks, of which approximately 30 million barrels are utilized in our transportation segment. Our activities from transportation operations generally consist of transporting crude oil and refined products 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 addition, we transport crude oil for third parties for a fee using our trucks and barges. These barge transportation services are provided through our 50% owned entity, Settoon Towing. Our transportation segment also includes our equity in earnings from our investment in Settoon Towing, Butte and Frontier. Butte and Frontier are pipeline systems in which we own approximately 22% and 22%, respectively. In connection with certain of our merchant activities conducted under our marketing business, we are also shippers on a number of 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 transportation segment for the periods indicated:

	Year Ended December 31, 2006	2005	2004
		(In millions)	
Operating Results(1)			
Revenues			
Tariff revenue	$ 449.5	$ 381.1	$ 309.9
Pipeline margin activities	23.6	20.0	18.1
Third-party trucking	60.9	34.1	20.9
Total pipeline operations revenues	534.0	435.2	348.9
Costs and Expenses			
Pipeline margin activities purchases	(3.2)	(2.0)	(1.5)
Third-party trucking	(68.1)	(48.2)	(26.4)
Field operating costs (excluding LTIP charge)	(200.7)	(164.5)	(131.0)
LTIP charge — operations(3)	(4.5)	(1.0)	(0.6)
Segment G&A expenses (excluding LTIP charge)(2)	(42.9)	(40.2)	(36.6)
LTIP charge — general and administrative(3)	(16.3)	(10.6)	(3.4)
Equity in earnings from unconsolidated entities	1.9	0.8	0.5
Segment profit	$ 200.2	$ 169.5	$ 149.9
Maintenance capital	$ 20.0	$ 8.5	$ 7.7
Segment profit per barrel	$ 0.26	$ 0.26	$ 0.28
Average Daily Volumes (thousands of barrels per day)(4)			
Tariff activities			
All American	49	51	54
Basin	332	290	265
BOA/CAM	89	N/A	N/A
Capline	160	132	123
Cushing to Broome	73	66	N/A
North Dakota/Trenton	89	77	39
West Texas/New Mexico Area Systems(5)	433	428	338
Canada	272	255	263
Other	521	426	330
Total tariff activities	2,018	1,725	1,412
Pipeline margin activities	88	74	74
Transportation Activities Total	2,106	1,799	1,486

(1) Revenues and purchases include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management's assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(3) Compensation expense related to our 1998 Long-Term Incentive Plan ("1998 LTIP"), our 2005 Long-Term Incentive Plan ("2005 LTIP"), and our 2006 Long-Term Incentive Tracking Unit Plan ("2006 Plan" and, together with the 1998 Plan and 2005 Plan, the "Long-Term Incentive Plans" or "LTIP").

(4) 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.

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

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

- Increased volumes and related tariff revenues — The increase in tariff revenues resulted from (i) higher volumes primarily from multi-year contracts on our Basin and Capline systems entered into during the third quarter of 2006 and the second quarter of 2006, respectively, (ii) increased volumes associated with the acquisition of the BOA/CAM/HIPS systems, (iii) higher volumes on various other systems, and (iv) increased revenues from loss allowance oil. As is common in the industry, our crude oil tariffs incorporate a “loss allowance factor” that is 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 subsequent sales of allowance oil barrels are also included in tariff revenues. Increased volumes and higher crude oil prices during 2006 as compared to 2005 have resulted in increased revenues related to loss allowance oil. The average NYMEX crude oil price for 2006 was $66.27 per barrel versus $56.65 in 2005 and $41.29 in 2004. The increase in volumes and related tariff revenues in 2005 versus 2004 is primarily related to the Link acquisition and other acquisitions completed during 2005 and 2004. The increase primarily resulted from the inclusion of the related assets for the entire 2005 period versus only a portion of the 2004 period.

- Increased field operating costs — Field operating costs have increased for most categories of costs for 2006 as we have continued to grow through acquisitions and expansion projects. The most significant cost increases in 2006 have been related to (i) payroll and benefits, (ii) utilities, (iii) integrity work, and (iv) property taxes. Utilities increased approximately $10 million in 2006 over the prior year due to a variety of factors including (i) an increase in electricity consumption related to increased volumes, partially offset by lower electricity market prices and (ii) a true-up of prior and current accruals following receipt of final billing information upon expiration of an existing term arrangement with a significant electricity provider. Our costs increased in 2005 as compared to 2004, primarily from the Link acquisition and other acquisitions completed during 2004. The 2005 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 2006 compared to 2005. The increase in segment G&A expenses in 2005 is primarily related to the acquisition activity.

- Increased LTIP expenses — LTIP charges included in field operating costs and segment G&A expenses increased approximately $9 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. LTIP-related charges increased approximately $8 million in 2005 over 2004, primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit. See Note 10 to our Consolidated Financial Statements.

As discussed above, the increase in transportation segment profit is largely related to our acquisition activities. We have completed a number of acquisitions during 2006, 2005 and 2004 that have impacted our results of operations. The following table summarizes the year-over-year impact that recent acquisitions and expansion projects have had on tariff revenue and volumes:

	Change in the Periods for the Year Ended December 31,			
	2006 vs 2005		2005 vs 2004	
		Volumes		Volumes
	(Volumes in thousands of barrels per day and revenues in millions)			
Tariff activities(1)(2)(3)				
2006 acquisitions/expansions	$ 32.8	178	$ N/A	N/A
2005 acquisitions/expansions	5.7	8	14.1	96
2004 acquisitions/expansions	2.7	28	22.6	140
2003 acquisitions/expansions	6.2	10	13.0	17
All other pipeline systems	21.0	69	21.5	60
Total tariff activities	$ 68.4	293	$ 71.2	313

(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 from the expansion 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 2006, average daily volumes from our tariff activities increased by approximately 300 thousand barrels per day or 17% and tariff revenues increased by approximately $68 million or 18%. The increase in volumes and tariff revenues is attributable to a combination of the following factors:

- Pipeline systems acquired or brought into service during 2006, which contributed approximately 178,000 barrels per day and $33 million of revenues during 2006;
- Revenues from some of the Canadian pipeline systems increased approximately $9 million in 2006 primarily due to the appreciation of Canadian currency (the Canadian to US dollar exchange rate appreciated to an average of 1.13 to 1 for 2006 compared to an average of 1.21 to 1 in 2005);
- An increase of approximately $7 million from our loss allowance oil primarily resulting from higher crude oil prices;
- Volumes and revenues from pipeline systems in which we entered into new multi-year contracts with shippers, which contributed approximately 70,000 barrels per day and approximately $4 million of revenues during 2006; and
- Increased volumes and revenues from the North Dakota/Trenton pipeline system resulting from our expansion activities on that system.

In 2005, average daily volumes from our tariff activities increased by approximately 300 thousand barrels per day or 22% and revenues from our tariff activities increased by approximately $71 million or 23%. The increase in total revenues is attributable to a combination of the following factors:

- 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 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 North Dakota/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. Transportation 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 marketing was increased by a comparable amount,
  - — An increase of 17,000 barrels per day and $4.4 million of revenues 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 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 of 5,000 barrels per day and $5.2 million of revenues from the Red River pipeline system 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 marketing segment.

Maintenance Capital

For the years ended December 31, 2006, 2005 and 2004, maintenance capital expenditures for our transportation segment were approximately $20.0 million, $8.5 million and $7.7 million, respectively. The increase in 2006 is due to our continued growth through acquisitions and expansion projects.

Facilities

As of December 31, 2006, we owned approximately 60 million barrels of active above-ground crude oil, refined products and LPG storage tanks, of which approximately 30 million barrels are included in our facilities segment. The remaining tanks are utilized in our transportation segment. At year end 2006, the Partnership was in the process of constructing approximately 12.5 million barrels of additional above ground terminalling and storage facilities, which we expect to place in service during 2007 and 2008.

Our facilities segment generally consists of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. On a stand-alone basis, segment profit from facilities activities is dependent on the storage capacity leased, volume of throughput and the level of fees for such services.

We generate fees through a combination of month-to-month and multi-year leases and processing arrangements. Fees generated in this segment include (i) storage fees that are generated when we lease tank capacity and (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil or refined products from one connecting pipeline and redeliver crude oil or refined products to another connecting carrier.

Our facilities segment also includes our equity earnings from our investment in PAA/Vulcan. At December 31, 2006, PAA/Vulcan owned and operated approximately 25.7 billion cubic feet of underground storage capacity and was constructing an additional 24 billion cubic feet of underground storage capacity.

Total revenues for our facilities segment have increased over the three-year period ended December 31, 2006. The revenue increase in each period is driven primarily by increased volumes resulting from our acquisition activities and, to a lesser extent, tankage construction projects completed in 2005 and 2006.

The following table sets forth our operating results from our facilities segment for the periods indicated:

	December 31,		
	2006	2005	2004
	(In millions, except per barrel amounts)		
Operating Results			
Storage and Terminalling Revenues(1)	$ 87.7	$ 41.9	$ 33.9
Field operating costs	(39.6)	(17.8)	(11.0)
LTIP charge — operations(3)	(0.1)	—	—
Segment G&A expenses (excluding LTIP charge)(2)	(13.5)	(7.7)	(3.6)
LTIP charge — general and administrative(3)	(5.7)	(2.2)	(1.1)
Equity earnings in unconsolidated entities	5.8	1.0	—
Segment profit	$ 34.6	$ 15.2	$ 18.2
Maintenance capital	$ 4.9	$ 1.1	$ 2.0
Segment profit per barrel	$ 1.49	$ 0.87	$ 1.23
Volumes (millions of barrels)(4)			
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	20.7	16.8	14.8
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	12.9	4.3	—
LPG processing (thousands of barrels per day)	12.2	—	—
Facilities activities total (average monthly capacity in millions of barrels)(5)	23.2	17.5	14.8

(1) Revenues include intersegment amounts.

(2) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management’s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(3) Compensation expense related to our Long-Term Incentive Plans.

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

(5) Calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing

volumes multiplied by the number of days in the month and divided by 1,000 to convert to monthly volumes in millions.

Segment profit (our primary measure of segment performance) and revenues were impacted in 2006 by the following:

- Increased revenues from crude facilities — The increase in volumes and related revenues during 2006 primarily relates to (i) increased volumes stored due to a pronounced contango market, (ii) the Pacific acquisition and other acquisitions completed during 2006 and 2005, and (iii) the utilization of capacity at the Mobile facility that was acquired from Link in 2004 but not used extensively until 2006;
- Increased revenues from LPG facilities — The increase in volumes and related revenues during 2006 primarily relates to four LPG facilities that were brought into service during 2005 but were operational for the entire 2006 period compared to only a portion of 2005;
- Increased revenues from refined product storage and terminalling — The Pacific acquisition introduced a refined products storage and terminalling revenue stream in 2006, which contributed additional revenues of $5.3 million; and
- Increased revenues from LPG processing — The acquisition of the Shafter processing facility during 2006 resulted in additional processing revenues of approximately $24 million.

Segment profit was also impacted in 2006 by the following:

- Increased field operating costs — Our continued growth, primarily from the acquisitions completed during 2006 and 2005 and the additional tankage added in 2006 and 2005, is the principal cause of the increase in field operating costs in 2006. Of the total increase, $10.9 million relates to the operating costs associated with the Shafter processing facility. The remainder of the increase in operating costs primarily relate to (i) payroll and benefits, (ii) maintenance and (iii) utilities;
- Increased segment G&A expenses — Segment G&A expenses excluding LTIP charges increased in 2006 compared to 2005 primarily as a result of an increase in the indirect costs allocated to the facilities segment in 2006 as the operations have grown in that period;
- Increased LTIP expenses — LTIP charges included in field operating costs and segment G&A expenses increased approximately $3.6 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. LTIP related charges increased approximately $1.1 million in 2005 over 2004 primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit (see Note 10 to our Consolidated Financial Statements); and
- Increased equity in earnings from unconsolidated entities — Our investment in PAA/Vulcan contributed $4.8 million in additional earnings, reflecting the inclusion of this investment for the entire 2006 period compared to only two months in 2005.

Segment profit and revenues also increased in 2005 compared to 2004 and were impacted by the following:

- Increased revenues from crude facilities — The increase in volumes and related revenues during 2005 primarily relates to (i) increased volumes stored due to a pronounced contango market, (ii) acquisitions completed during 2005 and 2004, and (iii) increased throughput at our Cushing terminal; and
- Increased revenues from LPG facilities — The increase in volumes and related revenues during 2005 primarily relates to acquisitions of new facilities completed during 2005; at the end of 2005, we owned ten facilities compared to four at the beginning of 2004.

Segment profit in 2005 was also impacted by the following:

- Increased field operating costs — Our continued growth, primarily from the acquisitions completed during 2005 and 2004 and the additional tankage added in 2005 and 2004, is the principal cause of the increase in

field operating costs in 2005. The increased costs primarily relate to (i) payroll and benefits, (ii) maintenance and (iii) utilities; and

- Increased segment G&A expenses — Segment G&A expenses excluding LTIP charges increased in 2005 compared to 2004 primarily as a result of an increase in the indirect costs allocated to the facilities segment in 2005 as the operations grew in that period. LTIP related charges increased approximately $1.1 million in 2005 over 2004 primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit.

Maintenance Capital

For the years ended December 31, 2006, 2005 and 2004, maintenance capital expenditures for our facilities segment were approximately $4.9 million, $1.1 million and $2.0 million, respectively. The increase in 2006 is primarily due to additional maintenance requirements at our Alto and Shafter facilities.

Marketing

Our revenues from marketing activities reflect the sale of gathered and bulk-purchased crude oil and LPG volumes, as well as marketing of natural gas liquids, 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. 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 our marketing segment volumes (which consist of (i) lease gathered volumes, (ii) LPG sales, and (iii) waterborne foreign crude imported) as well as the overall volatility and strength or weakness of market condition and the allocation of our assets among our various hedge positions. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our hedging activities 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 marketing operations were approximately $22.1 billion, $30.9 billion and $20.8 billion for the years ended December 31, 2006, 2005 and 2004, respectively. Total revenues for our marketing segment decreased in 2006 as compared to 2005 due to a combination of the following factors:

- A decrease in our 2006 revenues due to the adoption of EITF 04-13 which was equally offset with purchases and related costs and does not impact segment profit (see Note 2 to our Consolidated Financial Statements); offset by

- An increase in the average NYMEX price for crude oil in 2006 as compared to 2005. The average NYMEX price for crude oil was $66.27, $56.65 and $41.29 per barrel for the years ended December 31, 2006, 2005 and 2004, respectively. 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.

In order to evaluate the performance of this segment, management focuses on the following metrics: (i) segment profit, (ii) marketing segment volumes and (iii) segment profit per barrel calculated on these volumes. The following table sets forth our operating results from our marketing segment for the comparable periods indicated:

	December 31, 2006	December 31, 2005	December 31, 2004
	(In millions, except per barrel amounts)		
Operating Results(1)			
Revenues(2)(3)	$ 22,060.8	$ 30,893.0	$ 20,750.7
Purchases and related costs(4)(5)	(21,640.6)	(30,578.4)	(20,551.2)
Field operating costs (excluding LTIP charge)	(136.6)	(94.4)	(80.9)
LTIP charge — operations(6)	(0.1)	(2.3)	—
Segment G&A expenses (excluding LTIP charge)(7)	(39.5)	(32.5)	(35.2)
LTIP charge — general and administrative(6)	(16.0)	(10.0)	(2.8)
Segment profit(3)	$ 228.0	$ 175.4	$ 80.6
SFAS 133 mark-to-market adjustment(3)	$ (4.4)	$ (18.9)	$ 1.0
Maintenance capital	$ 3.3	$ 4.4	$ 1.6
Segment profit per barrel(8)	$ 0.80	$ 0.66	$ 0.34
Average Daily Volumes (thousands of barrels per day)(9)			
Crude oil lease gathering	650	610	589
LPG sales	70	56	48
Waterborne foreign crude imported	63	59	12
Marketing Activities Total	783	725	649

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

(2) Includes revenues associated with buy/sell arrangements of $4,761.9 million, $16,274.9 million and $11,396.8 million for the years ended December 31, 2006, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 919,500, 851,900 and 800,700 barrels per day for the years ended December 31, 2006, 2005 and 2004, 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 $4,795.1 million, $16,106.5 million and $11,280.2 million for the years ended December 31, 2006, 2005 and 2004, respectively. Volumes associated with these arrangements were approximately 926,800, 851,900 and 800,700 barrels per day for the years ended December 31, 2006, 2005 and 2004, 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 $49.2 million, $23.7 million and $2.0 million for the years ended December 31, 2006, 2005 and 2004, respectively.

(6) Compensation expense related to our Long-Term Incentive Plans.

(7) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management's assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(8) Calculated based on crude oil lease gathered volumes, LPG sales volumes, and waterborne foreign crude volumes.

(9) 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 for 2006 ($228.0 million) exceeded the segment profit for 2005 ($175.4 million). 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:

- Acquisitions — During 2006 we purchased certain crude oil gathering assets and related contracts in South Louisiana and Andrews Petroleum and Lone Star Trucking. The Andrews acquisition impacted our facilities, marketing and transportation segments. See Note 3 to our Consolidated Financial Statements.
- Favorable market conditions and execution of our risk management strategies — During 2006 and 2005, the crude oil market experienced significantly high volatility in prices and market structure. The NYMEX benchmark price of crude oil ranged from $54.86 to $78.40 during 2006. The volatile market allowed us to utilize risk management strategies to optimize and enhance the margins of our gathering and marketing activities. The market was in contango for most of 2006 and the time spread of prices averaged approximately $1.22 versus $0.72 for 2005; this increase in spreads was partially offset by an increase in the cost to carry the inventory that was not only impacted by the increase in LIBOR rates but also by the increase in NYMEX prices. Marketing segment profit includes contango and other hedged inventory related interest expense of approximately $49.2 million for 2006 incurred to store the crude oil. This cost is included in Purchases and related costs in the table above.
- SFAS 133 mark-to-market — 2006 includes SFAS 133 mark-to-market losses of $4.4 million compared to a loss of $18.9 million for 2005. See Note 6 to our Consolidated Financial Statements.
- Inventory Adjustment — In 2006, we recognized a $5.9 million non-cash charge primarily associated with declines in oil prices and other product prices during the third and fourth quarters of 2006 and the related decline in the valuation of working inventory volumes. Approximately $3.4 million of the charge relates to crude oil inventory in pipelines owned by third parties and the remainder relates to LPG and other products inventory.
- Field operating costs and segment G&A expenses — Field operating costs (excluding LTIP charges) increased in 2006 compared to 2005, primarily as a result of increases in (i) payroll and benefits and contract transportation as a result of 2006 acquisitions, (ii) fuel costs and (iii) maintenance costs. The increase in general and administrative expenses (excluding LTIP charges) is primarily the result of an increase in the indirect costs allocated to the marketing segment in 2006 as the operations have grown. The increase in field operating costs in 2005 compared to 2004 was primarily the result of an increase in (i) fuel costs and (ii) payroll and benefits.
- Increased LTIP expenses — LTIP charges included in field operating costs and segment G&A expenses increased approximately $3.8 million in 2006 over 2005, primarily as a result of an increase in our unit price to $51.20 at December 31, 2006 from $39.57 at December 31, 2005. LTIP related charges increased approximately $9.5 million in 2005 over 2004 primarily as a result of LTIP grants made in 2005 and an increase in our unit price. Our unit price at December 31, 2004 was $37.74 per unit. See Note 10 to our Consolidated Financial Statements.

Segment profit per barrel (calculated based on our marketing volumes included in the table above) was $0.80 for 2006, compared to $0.66 for 2005 and $0.34 for 2004. As discussed above, our current period results were 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 have recently been experienced, and these operating results may not be indicative of sustainable performance.

Maintenance capital

For the years ended December 31, 2006, 2005 and 2004, maintenance capital expenditures were approximately $3.3 million, $4.4 million, and $1.6 million, respectively, for our marketing segment.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $100.4 million for the year ended December 31, 2006, compared to $83.5 million and $68.7 million for the years ended December 31, 2005 and 2004, respectively. The increases in 2006 and 2005 related primarily to an increased amount of depreciable assets resulting from our acquisition activities and capital projects. Also contributing to the increase in 2005 was a non-cash loss related to sales of assets. Amortization of debt issue costs was $2.5 million in 2006, $2.8 million in 2005, and $2.5 million in 2004.

Interest Expense

Interest expense was $85.6 million for the year ended December 31, 2006, compared to $59.4 million and $46.7 million for the years ended December 31, 2005 and 2004, respectively. Interest expense is primarily impacted by:

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

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

	For the Year Ended December 31,					
	2006		2005		2004	
	Total	% of Total	Total	% of Total	Total	% of Total
			(Dollars in millions)			
Fixed rate senior notes(1)	$ 1,336	92 %	$ 891	87 %	$ 586	68 %
Borrowings under our revolving credit facilities(2)	118	8 %	135	13 %	274	32 %
Total	$ 1,454		$ 1,026		$ 860	

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

(2) Excludes borrowings under our senior secured hedged inventory facility and capital leases.

The issuance of senior notes and the assumption of Pacific's debt in 2006 resulted in an increase in the average amount of longer term and higher cost fixed-rate debt outstanding in 2006. The overall higher average debt balances in 2006 and 2005 were primarily related to the portion of our acquisitions that were not financed with equity, coupled with borrowings related to other capital projects. During 2006, 2005 and 2004, the average LIBOR rate was 5.0%, 3.2%, and 1.6%, respectively. Our weighted average interest rate, excluding commitment and other fees, was approximately 6.1% in 2006, compared to 5.6% and 5.0% in 2005 and 2004, respectively. The impact of the increased debt balance was an increase in interest expense of $26.0 million, and the impact of the higher weighted-average interest rate was an increase in interest expense of $4.7 million. Both of these increases were primarily offset by an increase in capitalized interest of $4.2 million. The net impact of the items discussed above was an increase in interest expense in 2006 of approximately $26.2 million.

The higher average debt balance in 2005 as compared to 2004 resulted in additional interest expense of approximately $12.7 million, while at the same time our commitment and other fees decreased by approximately $1.8 million. Our weighted average interest rate, excluding commitment and other fees, was approximately 5.6% for 2005 compared to 5.0% for 2004. The higher weighted average rate increased interest expense by approximately $12.7 million in 2005 compared to 2004.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our marketing 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 $49.2 million, $23.7 million and $2.0 million for the years ended December 31, 2006, 2005 and 2004, 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 that, 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. For example, during 2006 we entered the refined products transportation and storage business as well as the barge transportation business. 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 regulations in Canada) 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.

In September 2006, the DOT published a Notice of Proposed Rulemaking (“NPRM”) that proposed to regulate certain hazardous liquid gathering and low stress pipeline systems that are not currently subject to regulation. On December 6, 2006, the Congress passed, and on December 29, 2006 President Bush signed into law, H.R. 5782, the “Pipeline Inspection, Protection, Enforcement and Safety Act of 2006” (2006 Pipeline Safety Act), which reauthorizes and amends the DOT’s pipeline safety programs. Included in the 2006 Pipeline Safety Act is a provision eliminating the regulatory exemption for hazardous liquid pipelines operated at low stress, which was one of the focal points of the September 2006 NPRM. The Act requires DOT to issue regulations by December 31, 2007 for those hazardous liquid low stress pipelines now subject to regulation pursuant to the Act. Regulations issued by December 31, 2007 with respect to hazardous liquid low stress pipelines as well as any future regulation of hazardous liquid gathering lines could include requirements for the establishment of additional pipeline integrity management programs for these newly regulated pipelines. We do not currently know what, if any, impact these developments will have on our operating expenses and, thus, cannot provide any assurances that future costs related to these programs will not be material.

In addition to performing DOT-mandated pipeline integrity evaluations, during 2006, we expanded an internal review process started in 2005 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.
- The expected extension of DOT regulations to low stress and gathering pipelines.
- 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 addition of inspection requirements by EPA for storage tanks not subject to DOT's API 653 requirements.
- 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 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.

During 2006, we entered the refined products transportation and storage business. We believe that this business will be driven by increased demand for refined products, growth in the capacity of refineries and increased reliance on imports. We believe that demand for refined products will increase as a result of multiple specifications of existing products (also referred to as boutique gasoline blends), specification changes to existing products, such as ultra low sulfur diesel, and new products, such as bio-fuels. In addition, "capacity creep" as well as large expansion projects at existing refineries will likely necessitate construction of additional refined products transportation and storage infrastructure. We intend to grow our asset base in the refined products business through future acquisitions and expansion projects. We also intend to apply our business model to the refined products business by establishing and growing a marketing and distribution business to complement our strategically located assets.

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 flow from operations and our credit facilities are our primary sources of liquidity. At December 31, 2006, we had working capital of approximately $133 million, approximately $1.25 billion of availability under our committed revolving credit facilities and approximately $0.4 million of availability under our uncommitted hedged inventory facility. Usage of the credit facilities is subject to ongoing compliance with covenants. We believe we are currently in compliance with all covenants.

Cash flow from operations

The crude oil market was in contango for much of 2006 and 2005. Because we own crude oil storage capacity, during a contango market we can buy crude oil in the current month and simultaneously hedge the crude by selling it forward for delivery in a subsequent month. This activity can cause significant fluctuations in our cash flow from operating activities as described below.

The primary drivers of cash flow from our operations are (i) the collection of amounts related to the sale of crude oil and other products, the transportation of crude oil and other products for a fee, and storage and terminalling services, and (ii) the payment of amounts related to the purchase of crude oil and other products 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 (i) in the months that we store the purchased crude oil and hedge it by selling it forward for delivery in a subsequent month because of contango market conditions or (ii) in months in which we increase our share of linefill in third party pipelines. The storage of crude oil in periods of a contango market can have a material negative impact on our cash flows from operating activities for the period in which we pay for and store the crude oil (as is the case for much of 2006, including at December 31, 2006) and a material positive impact in the subsequent period in which we receive proceeds from the sale of the crude oil. In the month we pay for the stored crude oil, we borrow under our credit facilities (or pay from cash on hand) to pay for the crude oil, which negatively impacts our operating cash flow. 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, but to a lesser extent, the level of LPG and other product inventory stored and held for resale at period end affects our cash flow from operating activities.

In periods when the market is not in contango, we typically sell our crude oil during the same month in which we purchase it. Our accounts payable and accounts receivable generally vary proportionately because we make payments and receive payments for the purchase and sale of crude oil in the same month, which is the month following such activity. However, when the market is in contango, our accounts receivable, accounts payable, inventory and short-term debt balances are all impacted, depending on the point of the cycle at any particular period end. As a result, we can have significant fluctuations in those working capital accounts, as we buy, store and sell crude oil.

Our cash flow used in operating activities in 2006 was $275.3 million compared to cash provided by operating activities of $24.1 million in 2005. This change reflects cash generated by our recurring operations offset by an increase in certain working capital items of approximately $703 million. In 2006, the market was in contango and we increased our storage of crude oil and other products (financed through borrowings under our credit facilities), resulting in a negative impact on our cash flows from operating activities for the period, as explained above. The fluctuations in accounts receivable and other and accounts payable and other current liabilities are primarily related to purchases and sales of crude oil that generally vary proportionately.

Cash flow from operating activities was $24.1 million in 2005 and reflects cash generated by our recurring operations (as indicated above in describing the primary drivers of cash generated from operations), offset by changes in components of working capital, including an increase in inventory. A significant portion of the increased inventory has been purchased and stored due to contango market conditions and was paid for during the period via borrowings under our credit facilities or from cash on hand. As mentioned above, this activity has a negative impact in the period that we pay for and store the inventory. In addition, there was a change in working capital resulting from higher NYMEX margin deposits paid during 2005 that had a negative impact on our cash flows from operations. The fluctuations in accounts receivable and other and accounts payable and other current liabilities are primarily related to purchases and sales of crude oil that generally vary proportionately.

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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 factor 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.

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, 2006, we have approximately $1.1 billion of unissued securities remaining available under this registration statement.

Cash provided by financing activities was $1,927.0 million, $270.6 million and $554.5 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. During 2006, we borrowed under our credit facilities to pay for the storage of crude oil and other products under contango market conditions.

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 9 to our Consolidated Financial Statements:

2006		2005		2004	
Units	Net	Units	Net	Units	Net
6,163,960	$ 305.6	5,854,000	$ 241.9	4,968,000	$ 160.9
3,720,930	163.2	575,000	22.3	3,245,700	101.2
3,504,672	152.4		$ 264.2		$ 262.1
	$ 621.2				

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

(2) Excludes the common units issued and our general partner's proportionate capital contribution of $21.6 million pertaining to the equity exchange for the Pacific acquisition.

Senior Notes and Credit Facilities. During the three years ended December 31, 2006 we completed the sale of senior unsecured notes as summarized in the table below.

Year	Description	Face Value	Net Proceeds(1)
2006	6.125% Senior Notes issued at 99.56% of face value	$ 400	$ 398.2
	6.65% Senior Notes issued at 99.17% of face value	$ 600	$ 595.0
	6.7% Senior Notes issued at 99.82% of face value	$ 250	$ 249.6
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

(1) Face value of notes less the applicable discount (before deducting for initial purchaser discounts, commissions and offering expenses).

During the year ended December 31, 2006, we had net working capital and hedged inventory borrowings of approximately $618.8 million. These borrowings are used primarily for purchases of crude oil inventory that was stored. See "— Cash flow from operations." During 2006 and 2005, we also had net repayments on our long-term revolving credit facility of approximately $298.5 million and $143.7 million, respectively, resulting from cash generated from our operations and other financing activities. During 2004, we had net borrowings on our long-term revolving credit facility of approximately $64.9 million. During 2005, we had net working capital and hedged inventory borrowings of approximately $206.1 million and during 2004 we had net borrowings of approximately $42.8 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 Partner

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 partner. 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.

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		GP			
Year	Units	Units(1)		2%	Total	per Unit
2006	$ 224.9	$ —	$ 33.1	$ 4.6	$ 262.6	$ 2.87
2005	$ 178.4	$ —	$ 15.0	$ 3.6	$ 197.0	$ 2.58
2004	$ 142.9	$ 4.2	$ 8.3	$ 3.0	$ 158.4	$ 2.30

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

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2007 Capital Expansion Projects. Our 2007 projects include the following projects with the estimated cost for the entire year (in millions):

Projects	**2007**
St. James, Louisiana Storage Facility	$ 75.0
Salt Lake City Expansion	55.0
Patoka Tankage	40.0
Cheyenne Pipeline	34.0
Martinez Terminal	27.0
Cushing Tankage — Phase VI	27.0
Paulsboro Expansion	20.0
West Hynes Tanks	15.0
Kerrobert Tankage	14.0
Fort Laramie Tank Expansion	12.0
High Prairie Rail Terminal	11.0
Pier 400	10.0
Other Projects	160.0
Subtotal	500.0
Maintenance Capital	45.0
Total	$ 545.0

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.

Credit Facilities and Long-term Debt

In July 2006, we amended our senior unsecured revolving credit facility to increase the aggregate capacity from $1.0 billion to $1.6 billion and the sub-facility for Canadian borrowings from $400 million to $600 million. The amended facility can be expanded to $2.0 billion, subject to additional lender commitments, and has a final maturity of July 2011.

In November 2006, we amended our senior secured hedged inventory facility to increase the capacity under the facility from $800 million to $1.0 billion. We also extended the maturity of the senior secured hedged inventory facility to November 2007.

We also have several issues of senior debt outstanding that total $2.6 billion, excluding premium or discount, and range in size from $150 million to $600 million and mature at various dates through 2037. See Note 9 to our Consolidated Financial Statements.

In November 2006, in conjunction with the Pacific merger, we assumed two issues of Senior Notes with an aggregate principal balance of $425 million. Interest payments on the $175 million of 6.25% Senior Notes are due on March 15 and September 15 of each year. The notes mature on September 15, 2015. Interest payments on the $250 million of 7.125% Senior Notes are due on June 15 and December 15 of each year. The notes mature on June 15, 2014. We have the option to redeem the notes, in whole or in part, at any time on or after the date noted at the following redemption prices:

$175 Million 6.25% Notes		$250 Million 7.125% Notes	
Year	**Percentage**	**Year**	**Percentage**
September 2010	103.125%	June 2009	103.563%
September 2011	102.083	June 2010	102.375
September 2012	101.042	June 2011	101.188
September 2013 and thereafter	100.000	June 2012 and thereafter	100.000

In October 2006, we issued $400 million of 6.125% Senior Notes due 2017 and $600 million of 6.65% Senior Notes due 2037. The notes were sold at 99.56% and 99.17% of face value, respectively. Interest payments are due on January 15 and July 15 of each year. We used the proceeds to fund the cash portion of our merger with Pacific. Net proceeds in excess of the cash portion of the merger consideration were used to repay amounts outstanding under our credit facilities and for general partnership purposes. In anticipation of the issuance of these notes, we had entered into $200 million notional principal amount of U.S. treasury locks to hedge the treasury rate portion of the interest rate on a portion of the notes. The treasury locks were entered into at an interest rate of 4.97%.

During May 2006, we completed the sale of $250 million aggregate principal amount of 6.70% Senior Notes due 2036. The notes were sold at 99.82% of face value. Interest payments are due on May 15 and November 15 of each year. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

All our notes are fully and unconditionally guaranteed, jointly and severally, by all of our existing 100% owned subsidiaries, except for two subsidiaries with assets regulated by the California Public Utility Commission, and certain minor subsidiaries. See Note 12 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 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.

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Contingencies

See Note 11 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, 2006.

	Total	2007	2008	2009	2010	2011	2012 and Thereafter
				(In millions)			
Long-term debt and interest payments(1)	$ 5,181.6	$ 167.5	$ 167.5	$ 339.4	$ 159.2	$ 158.5	$ 4,189.5
Leases(2)	394.3	37.0	33.9	28.9	22.2	18.6	253.7
Capital expenditure obligations	11.5	11.5	—	—	—	—	—
Other long-term liabilities(3)	101.2	49.3	12.1	17.6	12.9	1.8	7.5
Subtotal	5,688.6	265.3	213.5	385.9	194.3	178.9	4,450.7
Crude oil and LPG purchases(4)	4,612.2	2,667.6	738.3	449.0	322.5	240.3	194.5
Total	$ 10,300.8	$ 2,932.9	$ 951.8	$ 834.9	$ 516.8	$ 419.2	$ 4,645.2

(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, 2006 (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 $21.4 million non-current liability related to SFAS 133 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, 2006, we had outstanding letters of credit of approximately $185.8 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 equity requests associated with certain projects specified in the joint venture agreement. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for up to 50% of such equity requests. In some cases, Vulcan Gas Storage's obligation is subject to a maximum amount, beyond which Vulcan Gas Storage's participation is optional. For any other capital expenditures, or capital expenditures with respect to which Vulcan Gas Storage's participation is optional, if Vulcan Gas Storage elects not to participate, we have the right to make additional capital contributions to fund 100% of the project until our interest in PAA/Vulcan equals 70%. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage's interest. Once PAA's ownership interest is 70% or more, Vulcan Gas Storage would have the right, but not the obligation, to make future 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, 2007, we paid a cash distribution of $0.80 per unit on all outstanding units. The total distribution paid was approximately $104.6 million, with approximately $87.5 million paid to our common unitholders and approximately $17.1 million paid to our general partner for its general partner interest ($1.8 million) and incentive distribution interest ($15.3 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.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts of its incentive distributions commencing with the earlier to occur of (i) the payment date of the first quarterly distribution declared and paid after the closing date that equals or exceeds $0.80 per unit or (ii) the payment date of the second quarterly distribution declared and paid after the closing date. Such adjustment shall be as follows: (i) $5 million per quarter for the first four quarters, (ii) $3.75 million per quarter for the next eight quarters, (iii) $2.5 million per quarter for the next four quarters, and (iv) $1.25 million per quarter for the final four quarters. Pursuant to this agreement, the incentive distribution paid to the general partner on February 14, 2007 was reduced by $5 million. The total reduction in incentive distributions will be $65 million.

In 2006, we paid $33.1 million in incentive distributions to our general partner. See Item 13. "Certain Relationships and Related Transactions, and Director Independence — Our General Partner."

Off-Balance Sheet Arrangements

We have invested in certain entities (PAA/Vulcan, Butte, Settoon Towing and Frontier) that are not consolidated in our financial statements. In conjunction with these investments, from time to time we may elect to provide financial and performance guarantees or other forms of credit support. See Note 9 to our Consolidated Financial Statements for more information concerning our obligations as they relate to our investment in PAA/Vulcan.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to various market risks, including volatility in (i) crude oil, refined products, natural gas 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, ICE 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, refined products, natural gas and LPG in storage, and expected purchases and sales of these commodities (relating primarily to crude oil and LPGs at this time). The derivative instruments utilized consist primarily of futures and option contracts traded on the NYMEX, ICE and over-the-counter transactions, including swap and option contracts entered into with financial institutions and other energy companies. Our policy is to purchase only commodity products for which we have a market, and to structure our sales contracts so that price fluctuations for those products do not materially affect the segment profit we receive. Except for the controlled trading program discussed below, we do not acquire and hold futures contracts or other derivative products for the purpose of speculating on price changes, as these activities could expose us to significant losses.

Although we seek to maintain a position that is substantially balanced within our various commodity purchase and sales activities (which mainly relate to crude oil and LPGs), 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, 2006 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 increase are shown in the table below:

	Fair Value	Effect of 10% Price Increase
	(In millions)	
Crude oil:		
Futures contracts	$ (13.5)	$ (54.9)
Swaps and options contracts	$ (27.8)	$ (23.6)
LPG and other:		
Futures contracts	$ (4.8)	$ 5.9
Swaps and options contracts	$ 13.6	$ 0.7
Total Fair Value	$ (32.5)	

The fair value of futures contracts is based on quoted market prices obtained from the NYMEX or ICE. The fair value of swaps and option contracts is 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 are 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 increase 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. In addition, in connection with the Pacific merger, we assumed interest rate swaps with an aggregate notional amount of $80 million. The interest rate swaps are a hedge against changes in the fair value of the 7.125% Senior Notes resulting from market fluctuations to LIBOR. 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, 2006. All of our senior notes are fixed rate notes and thus 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, 2006. 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						
	2007	2008	2009	2010	2011	Thereafter	Total
	(Dollars in millions)						
Liabilities:							
Short-term debt — variable rate	$ 993.5	$ —	$ —	$ —	$ —	$ —	$ 993.5
Average interest rate	5.8 %	—	—	—	—	—	5.8 %

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 may include forward exchange contracts and cross currency swaps.

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					
	2007	2008	2009	2010	2011	Total
Forward exchange contracts	$ (2.0)	$ —	$ —	$ —	$ —	$ (2.0)
Total	$ (2.0)	$ —	$ —	$ —	$ —	$ (2.0)

Financial Statements and Supplementary Data

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

Changes In and Disagreements With Accountants on Accounting and Financial Disclosure

Not applicable.

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, 2006, 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, 2006. See Management’s Report on Internal Control Over Financial Reporting on page F-2.

Other Information

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2006 that has not previously been reported.