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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." As of February 22, 2012, the closing market price for our common units was $81.51 per unit and there were approximately 159,000 record holders and beneficial owners (held in street name). As of February 22, 2012, there were 155,568,749 common units outstanding.

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

	Common Unit Price Range		Cash
	High	Low	Distributions [1]
2011			
4th Quarter	$ 73.55	$ 54.90	$ 1.0250
3rd Quarter	$ 64.98	$ 56.41	$ 0.9950
2nd Quarter	$ 65.69	$ 57.80	$ 0.9825
1st Quarter	$ 65.96	$ 60.21	$ 0.9700
2010			
4th Quarter	$ 65.20	$ 60.91	$ 0.9575
3rd Quarter	$ 64.21	$ 57.33	$ 0.9500
2nd Quarter	$ 60.06	$ 44.12	$ 0.9425
1st Quarter	$ 57.11	$ 49.82	$ 0.9350

(1) Cash distributions for a quarter are declared and paid in the following calendar quarter. See the "Cash Distribution Policy" below for a discussion of our policy regarding distribution payments.

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

In accordance with our partnership agreement, we will distribute all of our available cash to our unitholders within 45 days following the end of each quarter 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.

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing the acquisitions of Pacific Energy Partners LP ("Pacific") in November 2006, Rainbow Pipe Line Company, Ltd. ("Rainbow") in May 2008 and PAA Natural Gas Storage, LLC ("PNGS") in September 2009, our general partner agreed to reduce the amounts due to it as incentive distributions. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions was $83 million as displayed on an annual basis in the following table (in millions):

Acquisition	2007	2008	2009	2010	2011	Total
Pacific	$ 20	$ 15	$ 15	$ 10	$ 5	$ 65
Rainbow	—	3	6	1	—	10
PNGS	—	—	1	5	2	8
Total	$ 20	$ 18	$ 22	$ 16	$ 7	$ 83

The final $1 million of incentive distribution reductions related to these acquisitions was applied to the November 2011 distribution.

On December 1, 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. (the "BP NGL acquisition"). We expect this acquisition will close in the second quarter of 2012, subject to Canadian and U.S. regulatory approvals and customary closing conditions. Upon closing this acquisition, our general partner has agreed to reduce the amount of its incentive distributions by $15 million per year for two years, beginning with the first distribution paid following closing. Thereafter, our general partner has agreed to an ongoing reduction of $10 million per year. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL acquisition.

We paid $204 million to the general partner in incentive distributions in 2011. Additionally, on February 14, 2012, we paid a quarterly distribution of $1.025 per unit applicable to the fourth quarter of 2011, of which approximately $63 million was paid to the general partner in incentive distributions. 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. No such default has occurred. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities and Indentures."

See Item 12. "Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters" for information regarding securities authorized for issuance under equity compensation plans.

Issuer Purchases of Equity Securities

We did not repurchase any of our common units during the fourth quarter of 2011, and we do not have any announced or existing plans to repurchase any of our common units other than potential repurchases consistent with past practice in providing units for relatively small vestings of phantom units under our long-term incentive plans (“LTIP”).

Item 6. *Selected Financial Data*

The historical financial information below was derived from our audited consolidated financial statements as of December 31, 2011, 2010, 2009, 2008 and 2007 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,				
	2011	2010	2009	2008	2007
	(in millions, except for per unit data)				
Statement of operations data:					
Total revenues	$ 34,275	$ 25,893	$ 18,520	$ 30,061	$ 20,394
Net income	$ 994	$ 514	$ 580	$ 437	$ 365
Net income attributable to Plains	$ 966	$ 505	$ 579	$ 437	$ 365
Per unit data:					
Basic net income per limited partner unit	$ 4.91	$ 2.41	$ 3.34	$ 2.66	$ 2.47
Diluted net income per limited partner unit	$ 4.88	$ 2.40	$ 3.32	$ 2.64	$ 2.45
Declared distributions per limited partner unit [(1)]	$ 3.91	$ 3.76	$ 3.62	$ 3.50	$ 3.28
Balance sheet data (at end of period):					
Total assets	$ 15,381	$ 13,703	$ 12,358	$ 10,032	$ 9,906
Long-term debt	$ 4,520	$ 4,631	$ 4,142	$ 3,259	$ 2,624
Total debt	$ 5,199	$ 5,957	$ 5,216	$ 4,286	$ 3,584
Partners’ capital	$ 5,974	$ 4,573	$ 4,159	$ 3,552	$ 3,424
Other data:					
Net cash provided by operating activities	$ 2,365	$ 259	$ 365	$ 857	$ 796
Net cash used in investing activities	$ (2,020)	$ (851)	$ (686)	$ (1,339)	$ (663)
Net cash provided by/(used in) financing activities	$ (345)	$ 604	$ 338	$ 464	$ (124)
Capital expenditures:					
Acquisitions	$ 1,404	$ 407	$ 393	$ 735	$ 125
Internal growth projects	$ 531	$ 355	$ 364	$ 491	$ 525
Maintenance	$ 120	$ 93	$ 81	$ 81	$ 50
Investments in unconsolidated subsidiaries	$ —	$ —	$ 15	$ 37	$ 9

	Year Ended December 31,				
	2011	2010	2009	2008	2007
Volumes [2] [3]					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	2,942	2,889	2,836	2,851	2,712
Trucking	105	97	85	97	105
Transportation segment total	3,047	2,986	2,921	2,948	2,817
Facilities segment:					
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	70	61	56	53	46
Natural gas storage (average monthly capacity in billions of cubic feet)	71	47	26	14	13
LPG processing (average throughput in thousands of barrels per day)	14	14	15	17	18
Facilities segment total (average monthly capacity in millions of barrels)	82	70	61	56	48
Supply & Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	742	620	612	658	685
LPG sales	103	96	105	103	90
Waterborne cargos	21	68	55	80	71
Supply & Logistics segment total	866	784	772	841	846

(1) Our general partner is entitled, directly or indirectly, 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.

(2) Volumes associated with acquisitions represent total volumes for the number of days or months (dependent on the calculation) we actually owned the assets divided by the number of days or months in the year.

(3) Facilities total is calculated as the sum of: (i) crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products ("LPG") storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude British thermal unit ("Btu") equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

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

Introduction

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

Our discussion and analysis includes the following:

- Executive Summary
  - Company Overview
  - Overview of Operating Results, Capital Investments and Significant Activities
- Acquisitions and Internal Growth Projects
- Critical Accounting Policies and Estimates

Executive Summary

Company Overview

We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as the processing, transportation, fractionation, storage and marketing of natural gas liquids (“NGL”). The term NGL includes ethane and natural gasoline products as well as propane and butane, products which are also commonly referred to as liquid petroleum gas (“LPG”). The terms NGL and LPG are sometimes used interchangeably within this document depending on the context. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P., we also own and operate natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See “—Results of Operations—Analysis of Operating Segments” for further discussion.

Overview of Operating Results, Capital Investments and Significant Activities

During 2011, our net income attributable to Plains was $966 million, which was a $461 million year-over-year increase as compared to that recognized during 2010. This increase was primarily driven by strong industry fundamentals and contributions from our acquisitions and internal growth projects. The major items impacting comparability between periods were:

- the favorable results experienced within our supply and logistics segment, which were impacted by (i) the active development of crude oil and liquids-rich resource plays, (ii) favorable crude oil basis differentials and (iii) favorable market structure;
- the favorable results experienced within our transportation segment, which were impacted by (i) increased volumes in key production areas, (ii) increased tariff rates and (iii) favorable foreign currency exchange rates, partially offset by the unfavorable impact of a crude oil release on our Rainbow Pipeline; and
- the favorable results experienced within our facilities segment, which were impacted by expansions to our asset base through acquisitions and our ongoing internal growth projects.

Other key items impacting 2011 were:

- the completion of nine acquisitions for the aggregate consideration, net of cash acquired, of approximately $1.3 billion;
- the issuance of debt and equity for net proceeds of approximately $1.9 billion (this amount includes PNG’s issuance, in conjunction with the Southern Pines Acquisition, of approximately 17.4 million common units to third parties for net proceeds of approximately $370 million);
- the increase in our income tax expense related to our Canadian operations as a result of Canadian tax legislation changes that became effective on January 1, 2011; and
- the redemption of our 7.75% senior notes that were maturing in 2012 for approximately $222 million, as well as the loss of $23 million recognized in Other income/(expense), net within our Consolidated Financial Statements in conjunction with the early redemption of these notes.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2011, 2010 and 2009 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects, maintenance capital and investments in unconsolidated entities for the periods indicated (in millions):

	For the Year Ended December 31, 2011	2010	2009
Acquisition capital [1] [2]	$ 1,404	$ 407	$ 393
Internal growth projects	531	355	364
Maintenance capital	120	93	81
Investment in unconsolidated entities [1]	—	—	15
	$ 2,055	$ 855	$ 853

(1) Initial investments in unconsolidated entities are included within "Acquisition capital," whereas additional subsequent investments in unconsolidated entities are recognized within "Investment in unconsolidated entities."

(2) Acquisition capital for the year ended December 31, 2011 includes a cash deposit of $50 million (reflected in "Other current assets" on our Consolidated Balance Sheet) paid upon signing a definitive agreement related to the pending BP NGL acquisition, which is expected to close in the second quarter of 2012. See Note 3 to our Consolidated Financial Statements for further discussion of this pending acquisition.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under our credit facilities and the issuance of senior notes. Businesses acquired impact our results of operations commencing on the closing date of each acquisition. Our acquisition and capital expansion activities are discussed further in "—Liquidity and Capital Resources" and in Note 3 to our Consolidated Financial Statements. Information regarding acquisitions completed in 2011, 2010 and 2009 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
Southern Pines	02/09/2011	$ 765	Facilities
Gardendale Gathering System	11/29/2011	349	Transportation
Western	12/29/2011	220	Facilities and Transportation
Other [1]	Various	70	Transportation, Facilities and Supply & Logistics
2011 Total		$ 1,404	
Nexen	12/30/2010	$ 229	Supply & Logistics and Transportation
Other	Various	178	Transportation and Facilities
2010 Total		$ 407	
PNGS	09/03/2009	$ 215	Facilities
Other	Various	178	Transportation and Facilities
2009 Total		$ 393	

(1) Includes a cash deposit of $50 million (reflected in "Other current assets" on our Consolidated Balance Sheet) paid upon signing a definitive agreement related to the pending BP NGL acquisition, which is expected to close in the second quarter of 2012. See Note 3 to our Consolidated Financial Statements for further discussion of this pending acquisition.

Internal Growth Projects

Our 2011 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2011, 2010 and 2009 projects (in millions):

Projects	2011	2010	2009
PAA Natural Gas Storage (multiple projects) [1] [2]	$ 89	$ 85	$ 26
Rainbow II Pipeline [1]	44	3	—
Cushing - Phases VII and VIII	3	25	25
Cushing - Phases IX through XI	38	21	—
Basile Gas Processing Facility	37	14	2
Ross Rail Project [1]	27	—	—
Bumstead Facility	14	2	—
Bone Spring Project [1]	15	—	—
Patoka - Phases I through IV [1]	15	20	22
Eagle Ford Project [1]	18	—	—
Edmonton Land	—	17	—
West Texas Gathering Lines	—	15	—
Pier 400 [1]	13	11	18
Nipisi Storage and Truck Terminal [1]	9	6	18
Kerrobert Pumping Project	—	1	33
Rangeland Tankage	—	—	36
St. James - Phases I through III	—	21	73
Other projects [3]	209	114	111
Total	$ 531	$ 355	$ 364

(1) These projects will continue into 2012. See "—Liquidity and Capital Resources—Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests—2012 Capital Expansion Projects."

(2) Expenditures shown for 2009 for PNGS include only those expenditures made subsequent to the acquisition in September 2009 of the remaining 50% interest in PNGS.

(3) Primarily consists of pipeline connections, upgrades and truck stations and new tank construction and refurbishing.

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 ("GAAP"). These critical accounting policies are discussed in Note 2 to our Consolidated Financial Statements.

Critical Accounting Estimates

The preparation of financial statements in conformity with GAAP and rules and regulations of the United States Securities and Exchange Commission ("SEC") 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. On a regular basis, we evaluate our assumptions, judgments and estimates. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

We believe that the assumptions, judgments and estimates involved in the accounting for our (i) purchase and sales accruals, (ii) fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) fair value of derivatives, (iv) accruals and contingent liabilities, including our equity compensation plan accruals, (v) property and equipment and depreciation expense and (vi) allowance for doubtful accounts have the greatest potential impact on our consolidated financial statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates, so we consider these to be our critical accounting policies. Such critical accounting estimates are discussed further as follows:

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. For the year ended December 31, 2011, we estimate that approximately 2% of both annual revenues and cost of sales were recorded using purchase and sales estimates. Accordingly, a 10% variance from this estimate would impact annual revenues, cost of sales, operating income and net income attributable to Plains line items by approximately 1% or less on an annual basis. Although the resolution of these uncertainties has not historically had a material impact on our reported results of operations or financial condition, because of the high volume, low margin nature of our business, we cannot provide assurance that actual amounts will not vary significantly from estimated amounts. Variances from estimates are reflected in the period actual results become known, typically in the month following the estimate.

Fair Value of Assets and Liabilities Acquired and Identification of Associated Goodwill and Intangible Assets. In accordance with Financial Accounting Standards Board ("FASB") guidance regarding business combinations, with each acquisition, we allocate the cost of the acquired entity to the assets and liabilities assumed based on their estimated fair values at the date of acquisition. If the initial accounting for the business combination is incomplete when the combination occurs, an estimate will be recorded. Any subsequent adjustments to this estimate, if material, will be recognized retroactive to the date of acquisition. With exception to our equity method investments, we also expense the transaction costs as incurred in connection with each acquisition. In addition, we are required to recognize intangible assets separately from goodwill. Intangible assets with finite lives are amortized over their estimated useful life as determined by management. Goodwill and intangible assets with indefinite lives are not amortized but instead are periodically assessed for impairment.

Impairment testing entails estimating future net cash flows relating to the asset, based on management's estimate of future revenues, future cash flows and market conditions including pricing, demand, competition, operating costs and other factors. 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. 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 did not have any material goodwill impairments in 2011, 2010 or 2009. See Note 2 to our Consolidated Financial Statements for a further discussion of goodwill.

Fair Value of Derivatives. Our derivatives are reported at fair value as either assets or liabilities with changes in fair value recognized in either earnings or accumulated other comprehensive income ("AOCI"). The fair value of a derivative at a particular period end does not reflect the end results of a particular transaction, and will most likely not reflect the realized 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. For our derivatives that are not exchange traded, the estimates we use are based on indicative broker quotations or an internal valuation model. Our valuation models utilize market observable inputs such as price, volatility, correlation 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 internal valuation 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.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, asset retirement obligations, equity compensation plan accruals (as further discussed below) 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, 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 5% in our aggregate estimate for the accruals and contingent liabilities discussed above would have an impact on earnings of up to approximately $17 million. 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.

Equity Compensation Plan Accruals. We accrue compensation expense for outstanding equity compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity awards and recognize that fair value as compensation expense over the service period. For equity awards that contain a performance condition, the fair value of the equity award is recognized as compensation expense only if the attainment of the performance condition is considered probable. Uncertainties involved in this estimate include the actual unit price at time of vesting, whether or not a performance condition will be attained and the continued employment of personnel with outstanding equity awards.

We recognized total compensation expense of approximately $110 million, $98 million and $68 million in 2011, 2010 and 2009, respectively, related to equity awards granted under our various equity compensation plans. We cannot provide assurance that the actual fair value of our equity compensation awards will not vary significantly from estimated amounts. See Note 10 to our Consolidated Financial Statements.

Property and Equipment and Depreciation Expense. We compute depreciation using the straight-line method based on estimated useful lives. These estimates are based on various factors including condition, manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. During 2010 and 2011, we conducted a review to assess the useful lives of our property and equipment. See Note 2 to our Consolidated Financial Statements.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. For example, we are continuing to develop our Pier 400 project in California. Development of the project is still subject to the completion and execution of a land lease with the Port of Los Angeles, receipt of certain other regulatory approvals, as well as completion of commercial contracts with potential customers. We have capitalized $95 million of costs associated with this project and would assess the project for impairment if we determine that the project will not be developed. Any evaluation is highly dependent on the underlying assumptions of related cash flows. We consider the fair value estimate used to calculate impairment of property and equipment a critical accounting estimate. In determining the existence of an impairment of carrying value, we make a number of subjective assumptions as to:

- whether there is an event or circumstance that may be indicative of an impairment;

- the grouping of assets;
- the intention of "holding", "abandoning" or "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.

Impairments of approximately $5 million, $13 million and less than $1 million were recognized during 2011, 2010 and 2009, respectively, and were predominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and, in most instances, we utilized other assets to handle these activities.

Allowance for Doubtful Accounts. We perform credit evaluations of our customers and grant credit based on past payment history, financial conditions and anticipated industry conditions. Customer payments are regularly monitored and a provision for doubtful accounts is established based on specific situations and overall industry conditions. Our history of bad debt losses has been minimal and generally limited to specific customer circumstances; however, credit risks can change suddenly and without notice. See Note 2 to our Consolidated Financial Statements for additional discussion.

Recent Accounting Pronouncements

See Note 2 to our Consolidated Financial Statements for information regarding the effect of recent accounting pronouncements on our financial statements.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 13 to our Consolidated Financial Statements for a definition of segment profit (including an explanation of why this is a performance measure) and a reconciliation of segment profit to net income attributable to Plains.

Our segment analysis involves an element of judgment relating to the allocations between segments. In connection with its operations, the supply and logistics 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. Intersegment transportation service rates are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. Facilities segment services are also obtained at rates generally consistent with rates charged to third parties for similar services; however, certain terminalling and storage rates are discounted to our supply and logistics 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. Intersegment activities are eliminated in consolidation and we believe that the estimates with respect to these rates are reasonable. Also, our segment operating and general and administrative expenses reflect direct costs attributable to each segment; however, we also allocate certain operating expense and general and administrative overhead expenses between segments based on management's assessment of the business activities for the 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. We believe that the estimates with respect to these allocations are reasonable.

Non-GAAP Financial Measures

To supplement our financial information presented in accordance with GAAP, management uses additional measures that are known as "non-GAAP financial measures" in its evaluation of past performance and prospects for the future. The primary measures used by management are adjusted earnings before interest, taxes, depreciation and amortization ("adjusted EBITDA") and implied distributable cash flow ("DCF").

Management believes that the presentation of such additional financial measures provides useful information to investors regarding our performance and results of operations because these measures, when used in conjunction with related GAAP financial measures, (i) provide additional information about our core operating performance and ability to generate and distribute cash flow, (ii) provide investors with the financial analytical framework upon which management bases financial, operational, compensation and planning decisions and (iii) present measurements that investors, rating agencies and debt holders have indicated are useful in assessing us and our results of operations. These measures may exclude, for example, (i) charges for obligations that are expected to be settled with the issuance of equity instruments, (ii) the mark-to-market of derivative instruments that are related to underlying activities in another period (or the reversal of such adjustments from a prior period), (iii) items that are not indicative of our core operating results and business outlook and/or (iv) other items that we believe should be excluded in understanding our core operating performance. We have defined all such items hereinafter as "Selected Items Impacting Comparability." These additional financial measures are reconciled from the most directly comparable measures as reported in accordance with GAAP, and should be viewed in addition to, and not in lieu of, our consolidated financial statements and footnotes.

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP:

	For the Twelve Months Ended December 31,			Favorable/(Unfavorable)			
				2011-2010		2010-2009	
	2011	2010	2009	$	%	$	%
	(In millions, except per unit data)						
Transportation segment profit	$ 555	$ 516	$ 477	$ 39	8%	$ 39	8%
Facilities segment profit	358	270	208	88	33%	62	30%
Supply & Logistics segment profit	647	240	345	407	170%	(105)	(30)%
Total segment profit	1,560	1,026	1,030	534	52%	(4)	—%
Depreciation and amortization	(249)	(256)	(236)	7	3%	(20)	(8)%
Interest expense	(253)	(248)	(224)	(5)	(2)%	(24)	(11)%
Other income/(expense), net	(19)	(9)	16	(10)	(111)%	(25)	(156)%
Income tax benefit/(expense)	(45)	1	(6)	(46)	(4,600)%	7	117%
Net income	994	514	580	480	93%	(66)	(11)%
Less: Net income attributable to noncontrolling interests	(28)	(9)	(1)	(19)	(211)%	(8)	(800)%
Net income attributable to Plains	$ 966	$ 505	$ 579	$ 461	91%	$ (74)	(13)%
Net income attributable to Plains:							
Earnings per basic limited partner unit	$ 4.91	$ 2.41	$ 3.34	$ 2.50	104%	$ (0.93)	(28)%
Earnings per diluted limited partner unit	$ 4.88	$ 2.40	$ 3.32	$ 2.48	103%	$ (0.92)	(28)%
Basic weighted average units outstanding	149	137	130	12	9%	7	5%
Diluted weighted average units outstanding	150	138	131	12	9%	7	5%

The following table sets forth additional non-GAAP financial measures that are reconciled from the most directly comparable measures as reported in accordance with GAAP:

	For the Twelve Months Ended December 31,			Favorable/(Unfavorable)			
				2011-2010		2010-2009	
	2011	2010	2009	$	%	$	%
	(In millions, except per unit data)						
Net income	$ 994	$ 514	$ 580	$ 480	93%	$ (66)	(11)%
Add:							
Depreciation and amortization	249	256	236	(7)	(3)%	20	8%
Income tax (benefit)/expense	45	(1)	6	46	4,600%	(7)	(117)%
Interest expense	253	248	224	5	2%	24	11%
EBITDA	$ 1,541	$ 1,017	$ 1,046	$ 524	52%	$ (29)	(3)%
Selected Items Impacting Comparability of EBITDA							
Equity compensation expense [1]	$ (77)	$ (67)	$ (50)	$ (10)	(15)%	$ (17)	(34)%
Gains/(losses) from other derivative activities [2]	62	(14)	34	76	543%	(48)	(141)%
Inventory valuation adjustments net of gains from related derivative activities [2]	—	—	24	—	—%	(24)	(100)%
Net loss on early repayment of senior notes	(23)	(6)	(4)	(17)	(283)%	(2)	(50)%
Significant acquisition-related expenses	(10)	—	—	(10)	N/A	—	—%
Net gain/(loss) on foreign currency revaluation [3]	(7)	—	12	(7)	N/A	(12)	(100)%
Other [4]	(2)	(2)	8	—	—%	(10)	(125)%
Selected Items Impacting Comparability of EBITDA	$ (57)	$ (89)	$ 24	$ 32	36%	$ (113)	(471)%
EBITDA	$ 1,541	$ 1,017	$ 1,046	$ 524	52%	$ (29)	(3)%
Selected Items Impacting Comparability of EBITDA	57	89	(24)	(32)	(36)%	113	471%
Adjusted EBITDA	$ 1,598	$ 1,106	$ 1,022	$ 492	44%	$ 84	8%
Adjusted EBITDA	$ 1,598	$ 1,106	$ 1,022	$ 492	44%	$ 84	8%
Interest expense	(253)	(248)	(224)	(5)	(2)%	(24)	(11)%
Maintenance capital	(120)	(93)	(81)	(27)	(29)%	(12)	(15)%
Current income tax benefit/ (expense)	(38)	1	(15)	(39)	(3,900)%	16	107%
Equity earnings in unconsolidated entities, net of distributions	10	6	(8)	4	67%	14	175%
Distributions to noncontrolling interests [5]	(47)	(15)	(2)	(32)	(213)%	(13)	(650)%
Other	(1)	—	—	(1)	N/A	—	—%
Implied DCF	$ 1,149	$ 757	$ 692	$ 392	52%	$ 65	9%

(1) Our total equity compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards are included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The compensation expense associated with these awards is shown as a selected item impacting comparability in the table above. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting comparability. See Note 10 to our Consolidated Financial Statements for a comprehensive discussion regarding our equity compensation plans.

(2) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. When applicable, inventory valuation adjustments are presented with related derivative activity. See Note 6 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and hedging activities.

(3) During 2011 and 2009, there were significant fluctuations in the value of the Canadian dollar (“CAD”) to the U.S. dollar (“USD”), resulting in gains and losses that were not related to our core operating results of the period and were thus classified as selected items impacting comparability. See Note 6 to our Consolidated Financial Statements for further discussion regarding our currency exchange rate risk hedging activities.

(4) Includes other immaterial selected items impacting comparability.

(5) Includes distributions that pertain to the current quarter's net income and are to be paid in the subsequent quarter.

Transportation Segment

Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. The transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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

Operating Results (1) (in millions, except per barrel amounts)	Year Ended December 31, 2011	2010	2009	Favorable/(Unfavorable) 2011-2010 $	%	2010-2009 $	%
Revenues (1)							
Tariff activities	$ 1,005	$ 937	$ 867	$ 68	7%	$ 70	8%
Trucking	160	108	94	52	48%	14	15%
Total transportation revenues	1,165	1,045	961	120	11%	84	9%
Cost and Expenses (1)							
Trucking costs	(115)	(73)	(63)	(42)	(58)%	(10)	(16)%
Field operating costs (excluding equity compensation expense)	(387)	(346)	(333)	(41)	(12)%	(13)	(4)%
Equity compensation expense - operations (2)	(14)	(12)	(9)	(2)	(17)%	(3)	(33)%
Segment general and administrative expenses (excluding equity compensation expense)	(69)	(65)	(61)	(4)	(6)%	(4)	(7)%
Equity compensation expense - general and administrative (2)	(38)	(36)	(25)	(2)	(6)%	(11)	(44)%
Equity earnings in unconsolidated entities	13	3	7	10	333%	(4)	(57)%
Segment profit	$ 555	$ 516	$ 477	$ 39	8%	$ 39	8%
Maintenance capital	$ 86	$ 67	$ 57	$ (19)	(28)%	$ (10)	(18)%
Segment profit per barrel	$ 0.50	$ 0.47	$ 0.45	$ 0.03	6%	$ 0.02	4%

Average Daily Volumes (in thousands of barrels per day) (3)	Year Ended December 31, 2011	2010	2009	Favorable/(Unfavorable) 2011-2010 Volumes	%	2010-2009 Volumes	%
Tariff activities							
All American	35	39	40	(4)	(10)%	(1)	(3)%
Basin	440	378	394	62	16%	(16)	(4)%
Capline	160	223	193	(63)	(28)%	30	16%
Line 63/Line 2000	114	109	131	5	5%	(22)	(17)%
Salt Lake City Area Systems	137	135	131	2	1%	4	3%
Permian Basin Area Systems	404	371	368	33	9%	3	1%
Mid-Continent Area Systems	213	214	209	(1)	—%	5	2%
Manito	66	61	63	5	8%	(2)	(3)%
Rainbow	135	187	183	(52)	(28)%	4	2%
Rangeland	59	52	53	7	13%	(1)	(2)%
Refined products	102	116	100	(14)	(12)%	16	16%
Other	1,077	1,004	971	73	7%	33	3%
Tariff activities total	2,942	2,889	2,836	53	2%	53	2%
Trucking	105	97	85	8	8%	12	14%
Transporation segment total	3,047	2,986	2,921	61	2%	65	2%

(1) Revenues and costs and expenses include intersegment amounts.

(2) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIP Plans that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the "Selected Items Impacting Comparability" section of the table as shown within the "Results of Operations-Non-GAAP

Financial Measures" discussion above excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation plans.

(3) 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.

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 generally reflects a negotiated amount.

The following is a discussion of items impacting transportation segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our total transportation segment revenues, net of trucking costs, and volumes increased year-over-year for each comparative period presented. Noteworthy volume variances for 2011 compared to 2010 on our individual pipeline systems included (i) increased volumes on our Basin and Permian Basin Area Systems and certain of our Canadian pipelines driven by increased producer drilling in the surrounding regions and (ii) additional volumes of approximately 28,000 barrels per day for 2011 from the Robinson Lake pipeline acquired in connection with the Nexen acquisition in December 2010, which, in the Average Daily Volumes table above is included within "Other." These favorable volume variances were partially offset by (i) decreased volumes on our Rainbow System related to downtime associated with a pipeline release detected during April 2011 (see further discussion below) as well as a third-party competitor pipeline placed into service during the third quarter of 2011 and (ii) decreased volumes on our Capline Pipeline System, primarily related to shifts in refinery supply and unplanned refinery downtime.

The most noteworthy favorable volume variance for 2010 compared to 2009 was the increase of volumes on our Capline pipeline system that resulted from the additional 21% undivided joint interest that we purchased in this pipeline system during December 2009.

In addition to the impact of the volumetric variances discussed above, our transportation segment results were also impacted by the following for the years ended December 31, 2011, 2010 and 2009:

- Rate Changes — Revenues on our pipelines are impacted by various rate changes that may occur during the period. These rate changes primarily include the upward or downward indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate pipelines or other negotiated rate changes. During the comparable periods discussed herein, revenues fluctuated on our FERC regulated pipelines due to the upward indexing that was effective July 1, 2009 and July 1, 2011 and the downward indexing of the FERC rate that was effective as of July 1, 2010. Revenues were further impacted by increasing tariff rates on our Canadian pipelines.

- Foreign Exchange Impact — Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average CAD to USD exchange rates for 2011, 2010, and 2009 were $0.99 CAD: $1.00 USD, $1.03 CAD: $1.00 USD, and $1.14 CAD: $1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were favorably impacted by approximately $12 million for 2011 compared to 2010 and by approximately $24 million for 2010 compared to 2009 due to the appreciation of the Canadian dollar relative to the U.S. dollar.

- Loss Allowance Revenue — As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue increased by approximately $16 million for 2011 compared to 2010 and $9 million for 2010 compared to 2009. These increases were primarily due to a higher average realized price per barrel during each of the comparative periods (including the impact of gains from derivative activities). The increase for the 2011 period was partially offset by lower volumes.

- Trucking Business Activity — Trucking revenues, net of costs, increased by approximately $10 million for 2011 compared to 2010 primarily due to increased volumes in Canada resulting from increased producer drilling and downtime on the Rainbow Pipeline. See additional discussion regarding our Rainbow Pipeline release below as well as Note 11 to our Consolidated Financial Statements. Trucking revenues, net of costs, increased by approximately $4 million for 2010 compared to 2009 primarily due to volume increases from increased short-haul shipments and the addition of a heavy oil truck terminal at Nipisi, Alberta during December 2009, which was partially offset by higher fuel costs.

- Rainbow Pipeline System — As a result of a crude oil release that occurred in April 2011, volumes and revenues for the Rainbow Pipeline System were reduced due to pipeline downtime on a portion of the system, and expenses increased due to repair and response costs. In an unrelated development occurring shortly after the release, we experienced additional downtime and expenses related to forest fires in the same region. As a result of these incidents, for the year ended December 31, 2011, we estimate revenues were reduced by approximately $21 million. However, such unfavorable impacts were partially offset by the benefit of increased tariff rates on the system, as discussed further above. We resumed service on the impacted segment of the pipeline on August 30, 2011. See Note 11 to our Consolidated Financial Statements for further information regarding this pipeline release.

- Acquisitions — As discussed above, we acquired the Robinson Lake pipeline as part of the December 2010 Nexen acquisition. This pipeline contributed approximately $8 million of revenue for the year ended December 31, 2011.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to the impact of approximately $11 million of environmental remediation expenses associated with the Rainbow Pipeline release. See Note 11 to our Consolidated Financial Statements for further information regarding this release. Excluding costs associated with this incident, field operating costs per barrel increased approximately 6% in 2011 to $0.34 per barrel as compared to $0.32 per barrel in 2010 due to general cost increases and volume mix. Field operating costs for 2009 were approximately $0.32 per barrel.

Equity Compensation Expenses. Equity compensation expense increased during 2011 and 2010, primarily due to (i) an increase in unit price of $10.66 and $9.94 during 2011 and 2010, respectively, and (ii) additional awards that have been deemed probable of occurring. The increase in unit price impacts the fair value of our liability-classified awards. A majority of our equity compensation awards (including the Class B units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered to be probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At December 31, 2011 and 2010, we determined that PAA distribution levels of $4.35 and $4.00 per unit, respectively, that were previously improbable, were probable of occurring. We incurred additional expense in both periods as a result of the additional awards that were deemed probable of occurring. See Note 10 to our Consolidated Financial Statements for further information regarding our equity compensation plans.

Maintenance Capital. Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital in 2011 compared to 2010 and in 2010 compared to 2009 is primarily due to increased spending on pipeline integrity projects as well as timing of repairs between years.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities increased for year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to earnings from our 34% interest in White Cliffs Pipeline LLC, which we acquired in September 2010.

Facilities Segment

Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products, natural gas and LPG, as well as LPG fractionation and isomerization services. The facilities segment generates revenue through a combination of month-to-month and multi-year leases and processing arrangements.

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

Operating Results [1] (in millions, except per barrel amounts)	For the Year Ended December 31, 2011	2010	2009	Favorable/(Unfavorable) 2011-2010 $	%	2010-2009 $	%
Storage and terminalling revenues [1]	$ 605	$ 490	$ 362	$ 115	23%	$ 128	35%
Natural gas sales [2]	191	—	—	191	N/A	—	N/A
Storage related costs (natural gas related)	(22)	(23)	(5)	1	4%	(18)	(360)%
Natural gas costs [2]	(183)	—	—	(183)	N/A	—	N/A
Field operating costs (excluding equity compensation expense)	(165)	(140)	(120)	(25)	(18)%	(20)	(17)%
Equity compensation expense - operations [3]	(2)	(2)	(1)	—	—%	(1)	(100)%
Segment general and administrative expenses (excluding equity compensation expense)	(47)	(39)	(26)	(8)	(21)%	(13)	(50)%
Equity compensation expense - general and administrative [3]	(19)	(16)	(10)	(3)	(19)%	(6)	(60)%
Equity earnings in unconsolidated entities	—	—	8	—	—%	(8)	(100)%
Segment profit	$ 358	$ 270	$ 208	$ 88	33%	$ 62	30%
Maintenance capital	$ 22	$ 17	$ 16	$ (5)	(29)%	$ (1)	(6)%
Segment profit per barrel	$ 0.36	$ 0.32	$ 0.29	$ 0.04	13%	$ 0.03	10%

Volumes [4] [5]	For the Year Ended December 31, 2011	2010	2009	Favorable/(Unfavorable) 2011-2010 Volumes	%	2010-2009 Volumes	%
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	70	61	56	9	15%	5	9%
Natural gas storage (average monthly capacity in billions of cubic feet)	71	47	26	24	51%	21	81%
LPG processing (average throughput in thousands of barrels per day)	14	14	15	—	—%	(1)	(7)%
Facilities segment total (average monthly capacity in millions of barrels)	82	70	61	12	17%	9	15%

(1) Includes intersegment amounts.

(2) Natural gas sales and costs are attributable to the activities performed by PNG's commercial optimization group, which was established in 2010.

(3) The equity compensation expense presented in the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the "Selected Items Impacting Comparability" section of the table as shown in the "Results of Operations-Non-GAAP Financial Measures" discussion above excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation 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) Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) LPG processing volumes multiplied by the number of days in the year and divided by the number of months in the year.

The following is a discussion of items impacting facilities segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes. As noted in the table above, our facilities segment revenues, less storage related costs and natural gas purchases, and volumes increased year-over-year for each comparative year presented. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our ongoing acquisition and expansion activities as discussed below:

- PNG Acquisition and Expansion Projects — Revenues and volumes for 2011 compared to 2010 were favorably impacted by PNG's completion of the Southern Pines Acquisition, which closed on February 9, 2011. This acquisition contributed approximately $37 million of additional revenues, net of storage related costs, for 2011. Additionally, revenues and volumes for 2011 were further favorably impacted by the expansion of PNG's working gas capacity at the Pine Prairie facility.

  Revenues and volumes for 2010 compared to 2009 were impacted by the PNGS Acquisition, which closed during the third quarter of 2009. This acquisition and ongoing expansion activities at PNG contributed approximately $58 million of additional net revenue and approximately 22 billion cubic feet ("Bcf") of additional natural gas storage capacity for the year ended December 31, 2010. This net revenue amount includes the applicable storage related costs that are primarily due to increased volume of leased assets. Revenues were also favorably impacted by the acquisition of a natural gas processing business, which closed during the second quarter of 2009. This acquisition contributed approximately $9 million in additional revenue for the year ended December 31, 2010.

- Other Major Expansion Projects — Expansion projects that were completed in phases throughout recent years also favorably impacted revenues and volumes. These expansion projects were completed at some of our major terminal locations, and we estimate that such projects increased our revenues by approximately $28 million on a combined basis for the year ended December 31, 2011 compared to the year ended December 31, 2010 and by a combined $14 million for the year ended December 31, 2010 compared to the year ended December 31, 2009. Additions and expansions at our Cushing, Patoka and Wichita Falls facilities comprised the majority of the 9 million barrel increase in total crude oil, refined products and LPG storage average monthly capacity in 2011 as compared to 2010, while additions and expansions at our Cushing, Patoka and St. James facilities accounted for the majority of the 5 million barrel increase in 2010 as compared to 2009.

- Other — Revenues for all comparative periods also increased as a result of general escalations on existing leases.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) in general remained relatively constant on a per barrel basis during the comparative periods presented. The absolute increase in costs during each comparable period is consistent with the overall growth of the segment through (i) expansion projects at some of our major terminal and storage locations and (ii) acquisitions such as the Southern Pines, PNGS and natural gas processing business acquisitions discussed above.

Equity Earnings in Unconsolidated Entities. In the September 2009 PNGS Acquisition, we acquired the remaining 50% of PAA/Vulcan. As a result, we no longer have interests in unconsolidated entities associated with our facilities segment. See Note 3 to our Consolidated Financial Statements for additional discussion regarding this acquisition.

Maintenance Capital. The increase in maintenance capital in 2011 compared to 2010 is primarily due to increased integrity spending and is impacted by timing between years for various equipment replacements and repairs.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. 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 (i) increases or decreases in our supply and logistics segment volumes (which consist of lease gathered crude oil purchase volumes, LPG sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. 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 risk management activities provides a balance that provides general stability in our margins, these margins are not fixed and will vary from period to period.

The following table sets forth our operating results from our supply and logistics segment for the periods indicated:

Operating Results [1] (in millions, except per barrel amounts)	For the Year Ended December 31, 2011	2010	2009	Favorable/(Unfavorable) 2011-2010 Revenues	%	2010-2009 Revenues	%
Revenues	$ 33,068	$ 24,990	$ 17,759	$ 8,078	32%	$ 7,231	41%
Purchases and related costs [2]	(31,984)	(24,448)	(17,141)	(7,536)	(31)%	(7,307)	(43)%
Field operating costs (excluding equity compensation expense)	(314)	(195)	(183)	(119)	(61)%	(12)	(7)%
Equity compensation expense - operations [3]	(2)	(3)	(1)	1	33%	(2)	(200)%
Segment general and administrative expenses (excluding equity compensation expense)	(86)	(75)	(67)	(11)	(15)%	(8)	(12)%
Equity compensation expense - general and administrative [3]	(35)	(29)	(22)	(6)	(21)%	(7)	(32)%
Segment profit	$ 647	$ 240	$ 345	$ 407	170%	$ (105)	(30)%
Maintenance capital	$ 12	$ 9	$ 8	$ (3)	(33)%	$ (1)	(13)%
Segment profit per barrel	$ 2.05	$ 0.84	$ 1.22	$ 1.21	144%	$ (0.38)	(31)%

Average Daily Volumes [4] (in thousands of barrels per day)	For the Year Ended December 31, 2011	2010	2009	Favorable (Unfavorable) 2011-2010 Volume	%	2010-2009 Volume	%
Crude oil lease gathering purchases	742	620	612	122	20%	8	1%
LPG sales	103	96	105	7	7%	(9)	(9)%
Waterborne cargos	21	68	55	(47)	(69)%	13	24%
Supply & Logistics segment total	866	784	772	82	10%	12	2%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil inventory purchases) of approximately $20 million, $17 million, and $11 million for the years ended December 31, 2011, 2010, and 2009, respectively.

(3) The equity compensation expense presented in the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the "Selected Items Impacting Comparability" section of the table as shown in the "Results of Operations-Non-GAAP Financial Measures" discussion above excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements for additional discussion regarding our equity compensation plans.

(4) Calculated based on crude oil lease gathering purchased volumes, LPG sales volumes and waterborne cargo volumes.

The New York Mercantile Exchange ("NYMEX") benchmark price of crude oil ranged from approximately $75 to $115 per barrel, $64 to $92 per barrel, and $33 to $82 per barrel during 2011, 2010, and 2009, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for all periods presented, resulting from higher commodity prices and increases in volumes in the comparative 2011 and 2010 periods.

Generally, we expect a base level of earnings from our supply and logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. A contango market is favorable to our commercial strategies that are associated with storage as it allows us to simultaneously purchase production at current prices for storage and sell at higher prices for future delivery. A backwardated market can have a positive impact on our lease gathering margins because crude oil gatherers can capture a premium for prompt deliveries. However, in a backwardated market, there is little incentive to store crude oil as current prices are above future delivery prices. Our supply and logistics segment operating results are further impacted by foreign currency translations adjustments as certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates. Also, our LPG marketing operations are weather-sensitive, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period-to-period may have a significant effect on financial performance.

The following is a discussion of items impacting supply and logistics segment profit and segment profit per barrel for the periods indicated.

Operating Revenues and Volumes

2011 compared to 2010. Revenues, net of purchases and related costs, increased by approximately $542 million or 100% in 2011 compared to 2010. One of the principal drivers of this increase was the impact of higher volumes due to increased production related to the active development of crude oil and liquids-rich resource plays. The increase in volumes was primarily a result of increased drilling activities in the Bakken, Eagle Ford Shale, West Texas, Western Oklahoma and Texas Panhandle producing regions. Volumes also increased as a result of our December 2010 Nexen acquisition, which is primarily associated with the Bakken resource play. Another principal driver of our results was increased margins related to production volumes exceeding existing pipeline takeaway capacity in certain regions and the associated logistics challenges. As the infrastructure in these areas continues to be developed, we may not experience the same opportunities for enhanced margins that we have seen over the past year. We believe the fundamentals of our business remain strong; however, a normalization of margins may occur as the logistics challenges are addressed.

In addition, net revenues associated with our non-lease gathering activities increased for 2011 compared to 2010 as a result of (i) a more favorable market structure, (ii) more favorable crude oil quality differentials experienced in certain regions in 2011 and (iii) our mark-to-market valuation of our derivatives, as discussed further below. However, waterborne cargo volumes decreased over the 2011 period, which is primarily reflective of the increased domestic production.

2010 compared to 2009. Revenues, net of purchases and related costs, decreased by approximately $76 million or 12% in 2010 compared to 2009 despite our relatively consistent volumetric activity primarily due to (i) decreased LPG margins and (ii) our derivative activities (as shown in the table below). LPG margins for 2010 were negatively impacted by lower demand, while 2009 margins were higher than expected due to the liquidation of lower valued inventory following a write-down of inventory values during 2008. The 2010 period was also unfavorably impacted compared to 2009 due to (i) a less favorable market structure and (ii) less favorable crude oil quality differentials; however, these unfavorable variances were partially offset by improved margins within our lease gathering activities.

Impact from derivative activities. The impact of the mark-to-market valuation of our derivative activities on net revenues was as follows (in millions):

	For the Twelve Months Ended December 31,			Variance	
	2011	2010	2009	2011-2010	2010-2009
Gains/(losses) from derivative activities[1]	$ 62	$ (17)	$ 38	$ 79	$ (55)

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. See Note 6 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and hedging activities.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased year-over-year for each of the comparative periods primarily due to increased use of third-party contractors to truck lease gathered volumes, particularly in the Rockies, due to the Nexen acquisition completed in the fourth quarter of 2010.

Equity Compensation Expense. Equity compensation expense increased for the comparative periods presented. See a discussion regarding such increases within the Transportation Segment above. Also, see Note 10 to our Consolidated Financial Statements for additional information on our equity compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and Amortization. Depreciation and amortization expense was $249 million for the year ended December 31, 2011 compared to $256 million and $236 million for the years ended December 31, 2010 and 2009, respectively. Included within 2011 and 2010 depreciation expense are reductions resulting from extensions of the depreciable lives of several of our crude oil and other storage facilities and pipeline systems. The extension of depreciable lives is based on an internal review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and technology. The reductions of depreciation expense associated with the extensions of depreciable lives were $23 million in 2010 and $60 million (incrementally by $37 million as compared to the prior year) in 2011. This decrease was offset by an increased amount of assets resulting from our acquisition activities, including Southern Pines and Nexen in 2011 and PNGS and a natural gas processing business in 2010 as well as various internal growth projects in both years.

Included in depreciation expense for the years ended December 31, 2011, 2010 and 2009 are net losses of approximately $11 million, $13 million and $1 million, respectively, recognized upon disposition of certain assets and impairments for assets taken out of service. Amortization of debt issue costs was $7 million, $7 million and $6 million in 2011, 2010 and 2009, respectively.

Interest Expense

Interest expense was $253 million for the year ended December 31, 2011, compared to $248 million and $224 million for the years ended December 31, 2010 and 2009, respectively. Interest expense is primarily impacted by:

- our weighted 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 the components impacting the interest expense variance for the years ended December 31, 2011 and 2010 (in millions, except for percentages):

	$	Average LIBOR Rate	Weighted Average Interest Rate [1]
Interest expense for the year ended December 31, 2009	$ 224	0.3%	6.0%
Impact of retirement of senior notes [2][3]	(21)		
Impact of issuance of senior notes [4][5]	48		
Other	(3)		
Interest expense for the year ended December 31, 2010	$ 248	0.3%	5.3%
Impact of retirement of senior notes [3][6]	(22)		
Impact of issuance of senior notes [5][7]	38		
Impact of capitalized interest	(9)		
Impact of credit facilities	(6)		
Other	4		
Interest expense for the year ended December 31, 2011	$ 253	0.1%	5.4%

(1) Excludes commitment and other fees.

(2) During 2009, we redeemed our outstanding $250 million 7.125% senior notes due 2014, and our $175 million 4.75% notes matured.

(3) In September 2010, we redeemed our outstanding $175 million 6.25% senior notes due 2015.

(4) During 2009, we issued $1.35 billion of senior notes (see "Liquidity and Capital Resources—*Equity and Debt Financing Activities*" below for additional discussion).

(5) In July 2010, we completed the issuance of $400 million of 3.95% senior notes due 2015.

(6) In February 2011, we redeemed our outstanding $200 million 7.75% senior notes due 2012.

(7) In January 2011, we completed the issuance of $600 million of 5.00% senior notes due 2021.

Interest costs attributable to borrowings for inventory stored in a contango market are included in purchases and related costs in our supply and logistics 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 $20 million, $17 million, and $11 million for the years ended December 31, 2011, 2010, and 2009, respectively.

Other Income/(Expense), Net

Other income/(expense), net for the year ended December 31, 2011, was primarily impacted by (i) a loss of approximately $23 million that was recognized in conjunction with the early redemption of our $200 million, 7.75% senior notes in February 2011 and (ii) a net gain of approximately $4 million related to foreign currency revaluations of CAD-denominated interest receivables associated with intercompany notes and the impact of related foreign currency hedges.

The 2010 period primarily included (i) a loss of approximately $6 million recognized in connection with the early redemption of our $175 million 6.25% senior notes, (ii) the revaluation of contingent consideration related to our PNGS acquisition of approximately $2 million and (iii) a net loss of approximately $2 million related to the foreign currency revaluation of a CAD-denominated interest receivable associated with an intercompany note and the impact of related foreign currency hedges.

Other income/(expense), net for the year ended December 31, 2009 was primarily impacted by (i) a net gain of approximately $9 million recognized in connection with the PNGS acquisition (see Note 3 to our Consolidated Financial Statements for further discussion), (ii) a net gain of approximately $11 million related to the foreign currency revaluation of a CAD-denominated interest receivable associated with an intercompany note and the impact of related foreign currency hedges and (iii) a loss of approximately $4 million recognized in conjunction with the early redemption of our $250 million 7.13% senior notes.

Income Tax Expense

Current income tax expense increased for year ended December 31, 2011 compared to the year ended December 31, 2010 primarily due to an increase in the level of taxable earnings in our entities subject to Canadian federal and provincial taxes. As a result of Canadian tax legislation changes, we restructured our Canadian investment on January 1, 2011 and all of our Canadian operations are subject to Canadian corporate tax at a rate of approximately 27% in 2011. In addition, payments of interest and dividends from our Canadian entities to other affiliates are subject to Canadian withholding tax which is also treated as income tax expense. Previously, a portion of the activities were conducted in a flow-through entity that was not subject to entity-level taxation. Current income tax expense decreased in 2010 compared to 2009 due to a decrease in the level of taxable earnings in that year in our entities subject to Canadian federal and provincial taxes. There was a deferred tax expense increase for 2011 compared to 2010 and 2010 compared to 2009 due to a decrease in book depreciation rates. Tax depreciation is now in excess of book depreciation. See Note 7 to our Consolidated Financial Statements for further discussion.

Outlook

Although the U.S. and European economies remain weak and face significant uncertainties, on balance, we believe current and foreseeable U.S. energy industry fundamentals are favorable for PAA's asset base and business model. On the negative side, U.S. petroleum consumption has averaged around 19.1 million barrels per day for the last few years, a level that is approximately 8% below levels experienced in 2005 to 2007. Conversely, as a result of attractive crude oil and liquids prices, advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays, U.S. crude oil and liquids production has increased in multiple regions in the lower 48 states. This production increase represents a reversal of multiple decades of declining production levels. A significant portion of these U.S. drilling activities is focused in areas where we have a significant asset presence, increasing the utilization of our existing assets as well as providing multiple opportunities to expand and extend our existing asset base on attractive terms.

Additionally, the crude oil market has experienced volatility in location and basis differentials as a result of international supply concerns, the quality of domestic production increases and regional infrastructure constraints. During 2011, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities available in a volatile environment. If these volatile market conditions persist, we believe we will have the opportunity to optimize the use of our existing assets.

There can be no assurance that U.S. production increases will continue or that we will not be negatively affected by potential volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely reduce the infrastructure constraints, which will ultimately reduce unit margins and we cannot be certain that our expansion efforts will generate targeted returns or that any future acquisition activities will be successful. See Item 1A. "Risk Factors - Risks Related to Our Business."

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our cash flow from operations as further discussed below in the section entitled "—Cash Flow from Operations" and (ii) borrowings under our credit facilities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil and other products and other expenses and interest payments on our outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through our primary sources of liquidity. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. As of December 31, 2011, we had a working capital deficit of approximately $160 million and over $3.6 billion of liquidity available to meet our ongoing operational, investing and finance needs as of December 31, 2011 as noted below (in millions):

	As of December 31, 2011
Availability under PAA senior unsecured revolving credit facility	$ 1,560
Availability under PAA senior secured hedged inventory facility	752
Availability under PNG senior unsecured revolving credit facility	126
Availability under PAA senior unsecured 364-day revolving credit facility [1]	1,200
Cash and cash equivalents	26
Total	$ 3,664

(1) As of December 31, 2011, this facility had not been activated. See "Credit Facilities and Indentures" for more information regarding this credit facility.

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Item 1A. "Risk Factors" for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank Act"). Although the Dodd-Frank Act includes provisions regarding the use of financial instruments, and the scope and applicability of these provisions as implemented may continue to develop, our current assessment is that the direct effects of the Dodd-Frank Act on PAA will be limited to additional documentation and record-keeping requirements. We cannot, however, predict the effect the Dodd-Frank Act may have on the futures and capital markets, which may affect the depth and quality of our counterparties and lenders and, as a result, our liquidity and access to capital.

Cash Flow from Operations

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 provided for a fee and (ii) the payment of amounts related to the purchase of crude oil and other products and other expenses, principally field operating costs, general and administrative expenses and interest expense. 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 or long-term inventory. In addition, our cash flow from operations may be impacted by the timing of settlement of our derivative activities. Gains and losses from settled instruments that qualify as effective cash flow hedges are deferred in AOCI, but may impact operating cash flow in the period settled.

The storage of crude oil in periods of a contango market, when the price of crude oil for future deliveries is higher than current prices, can have a material impact on our cash flows from operating activities. 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, 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 and we do not rely on borrowings under our credit facilities to pay for the crude oil. During such market conditions, our accounts payable and accounts receivable generally move in tandem as 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. In periods during which we build inventory or linefill, regardless of market structure, we may rely on our credit facilities to pay for the inventory or linefill.

Net cash flow provided by operating activities for the twelve months ended December 31, 2011 was approximately $2.4 billion. The cash provided by operating activities reflects cash generated by our recurring operations, and is also significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage as discussed above. During 2011, we reduced our overall inventory levels resulting in a positive impact to operating cash flow. The reduction in our crude oil inventory levels is primarily due to liquidating a certain amount of inventory that had been stored in the contango market, which primarily began liquidating during the latter portion of the second quarter, as well as liquidating the inventory stored through our waterborne cargo purchase activity, which occurred throughout the third and fourth quarters.

Net cash flows provided by operating activities for the twelve months ended December 31, 2010 and 2009 were approximately $259 million and $365 million, respectively. During both the 2010 and 2009 periods, we increased the amount of our inventory. The increases were due to both increased volumes and prices and were primarily related to our crude oil storage activities and, for 2010, our LPG activities. The net increased levels of inventory were financed through borrowings under our credit facilities and senior notes issuances resulting in a negative impact to our operating cash flow for the period.

Credit Facilities and Indentures

PAA senior unsecured 364-day revolving credit agreement. In December, 2011 we entered into a 364-day credit facility agreement with a borrowing capacity of $1.2 billion. As of December 31, 2011 this facility had not been activated. Pursuant to its terms, PAA may activate the facility at any time over a six-month period, resulting in a maturity 364 days from the activation date. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time.

PAA senior unsecured revolving credit facility. In August 2011, we entered into an unsecured revolving credit agreement with a committed borrowing capacity of $1.6 billion (including a $600 million Canadian sub-facility) which contains an accordion feature that enables us to increase the committed capacity to $2.1 billion, subject to obtaining additional or increased lender commitments. The credit agreement provides for the issuance of letters of credit and has a maturity date in August 2016. Borrowings accrue interest based, at our election, on the Eurocurrency Rate, the Base Rate or the Canadian Prime Rate, in each case plus a margin based on our credit rating at the applicable time. This facility replaced a similar $1.6 billion senior unsecured revolving credit facility that was scheduled to mature in July 2012. At December 31, 2011, we had approximately $1.56 billion of available borrowing capacity under our $1.6 billion committed revolving credit facility. Of the capacity we utilized at December 31, 2011, approximately $7 million was associated with outstanding letters of credit and the remainder was borrowed.

PAA senior secured hedged inventory facility. In August 2011, we replaced our previous $500 million senior secured hedged inventory facility that was scheduled to mature in October 2011 with a new $850 million senior secured hedged inventory facility (of which $250 million is available for the issuance of letters of credit) that expires in August 2013. Subject to obtaining additional or increased lender commitments, the committed amount of this new facility may be increased to $1.35 billion. Initial proceeds from the facility were used to refinance the outstanding balance of the previous facility, and subsequent proceeds from this facility will be used to finance purchased or stored hedged inventory. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable and will be repaid from the proceeds of the sale of the financed inventory. Borrowings accrue interest based, at our election, on either the Eurocurrency Rate or the Base Rate, in each case plus a margin based on our credit rating at the applicable time. At December 31, 2011, we had approximately $752 million of available borrowing capacity under our $850 million committed hedged inventory facility. Of the capacity we utilized at December 31, 2011, approximately $23 million was associated with outstanding letters of credit and the remainder was borrowed.

PNG senior unsecured revolving credit facility. In August 2011, our consolidated subsidiary PNG entered into a five year, $450 million senior unsecured credit agreement , which provides for (i) $250 million under a revolving credit facility, which may be increased at PNG's option to $450 million (subject to receipt of additional or increased lender commitments) and (ii) two $100 million term loan facilities (the "GO Zone term loans") pursuant to the purchase, at par, of the GO Bonds acquired by PNG in conjunction with the Southern Pines Acquisition (see Note 3 to our Consolidated Financial Statements). The revolving credit facility expires in August 2016, and the purchasers of the two GO Zone term loans have the right to put, at par, to PNG the GO Zone term loans in August 2016. The GO Bonds mature by their terms in May 2032 and August 2035, respectively. Borrowings under the revolving credit facility accrue interest, at PNG's election, on either the Eurodollar Rate or the Base Rate, in each case plus an applicable margin. The GO Zone term loans accrue interest in accordance with the interest payable on the related GO Bonds purchased with respect thereto as provided in such GO Bonds and the GO Bonds Indenture pursuant to which such GO Bonds are issued and governed. At December 31, 2011, PNG had approximately $126 million of available borrowing capacity under the revolving credit facility. Of the capacity we utilized at December 31, 2011, approximately $3 million was associated with outstanding letters of credit and the remainder was borrowed. This credit facility restricts, among other things, PNG's ability to make distributions of available cash to unitholders if any default or event of default, as defined in the credit agreement, exists or would result therefrom. In addition, the credit facility contains certain financial and other restrictive covenants.

Indentures. We had several issues of senior debt outstanding at December 31, 2011 that totaled approximately $4.8 billion, excluding premium or discount, range in size from $150 million to $600 million and mature at various dates between 2012 and 2037. See Note 4 to our Consolidated Financial Statements.

Our credit agreements and the indentures governing our senior notes contain cross-default provisions. A default under our credit facilities would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with the provisions in 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. See Note 4 to our Consolidated Financial Statements for additional discussion regarding our credit facilities and long-term debt.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our LPG business, contango market activities, and waterborne cargo activities as well as refinancing of our debt maturities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

Registration Statements. We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities ("Traditional Shelf"). At December 31, 2011, we had $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement ("WKSI Shelf"), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. Our January 2011offering of our $600 million 5.00% senior notes due 2021 and our March 2011 and November 2011 equity offerings, as discussed further below, were all conducted under the WKSI Shelf.

PNG has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PNG to issue up to an aggregate of $1.0 billion of debt or equity securities. PNG has not issued any securities under its shelf registration statement.

During August 2011, Vulcan Energy Corporation completed a secondary public offering of 7,500,000 common units representing limited partner interests in us at $61.10 per common unit. We did not receive any of the proceeds from the offering, and the number of PAA common units outstanding did not change as a result of this transaction. The secondary offering was not conducted under our Traditional Shelf or WKSI Shelf, but was conducted under a previously filed resale shelf registration statement.

PAA Equity Offerings. We completed equity offerings during 2011, 2010, and 2009 as summarized in the table below (net proceeds in millions). These offerings include our general partner's proportionate capital contributions and are net of costs associated with the offerings.

Year	Units	Net Proceeds [1]
2011	13,935,000	$ 889
2010	4,780,000	$ 296
2009	11,040,000	$ 456

(1) We used the net proceeds to reduce outstanding borrowings under our credit facilities and for general partnership purposes. Amounts repaid under our credit facilities may be reborrowed to fund our ongoing capital program, potential future acquisitions or for general partnership purposes.

PNG Equity Offerings. On May 5, 2010, PNG completed its IPO of 13.5 million common units representing limited partner interests at $21.50 per common unit for total proceeds of approximately $268 million. Additionally, in conjunction with the Southern Pines Acquisition, PNG completed a private placement of 17.4 million common units to third parties for net proceeds of approximately $370 million, and the sale to us of approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million. Our aggregate ownership interest in PNG is approximately 64%. See Note 5 to our Consolidated Financial Statements.

Senior Notes. During the last three years we issued senior unsecured notes as summarized in the table below (in millions):

Year	Description	Maturity	Face Value	Net Proceeds[1]
2011	5.00% Senior Notes issued at 99.521% of face value [2]	February 2021	$ 600	$ 597
2010	3.95% Senior Notes issued at 99.889% of face value [3]	September 2015	$ 400	$ 400
2009	5.75% Senior Notes issued at 99.523% of face value [4]	January 2020	$ 500	$ 499
	4.25% Senior Notes issued at 99.802% of face value	September 2012	$ 500	$ 497
	8.75% Senior Notes issued at 99.994% of face value	May 2019	$ 350	$ 350

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

(2) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities and for general partnership purposes. In addition, we used a portion of the proceeds to redeem all of our outstanding $200 million 7.75% senior notes due 2012, as discussed further below.

(3) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities. In addition, we used a portion of the proceeds to redeem all of our outstanding $175 million 6.25% senior notes due 2015, as discussed further below.

(4) We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS acquisition (which included repayment of all of PNGS's debt). In addition, we used a portion of the proceeds to redeem all of our outstanding $250 million 7.13% senior notes due 2014 (in conjunction with the early redemption of these notes, we recognized a loss of approximately $4 million).

In February 2011, our $200 million 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

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In September 2010, we repaid our $175 million 6.25% senior notes and recognized a loss of approximately $6 million in conjunction with the early redemption of these notes. We utilized net proceeds from our July 2010 issuance of $400 million 3.95% senior notes to retire these senior notes.

In August 2009, our $175 million 4.75% senior notes matured. We utilized cash on hand and available capacity under our credit facilities to retire these senior notes.

Acquisitions, Capital Expenditures and Distributions Paid to Our Unitholders, General Partner and Noncontrolling Interests

In addition to operating needs discussed above, we also use cash for our acquisition activities, internal growth projects and distributions paid to our unitholders, general partner and noncontrolling interests. 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. See "—Acquisitions and Internal Growth Projects" for further discussion of such capital expenditures.

Acquisitions. The price of the acquisitions includes cash paid, 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.

In December 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company for a total consideration of approximately $1.67 billion with an expected closing to occur during the second quarter of 2012 (see Note 3 to our Consolidated Financial Statements). Giving effect to this transaction, our available liquidity as of December 31, 2011 of over $3.6 billion would have decreased to approximately $2 billion.

2012 Capital Expansion Projects. We expect the majority of funding for our 2012 capital program will be provided by revolver borrowings and cash flow in excess of partnership distributions as well as through our access to the capital markets for equity and debt as we deem necessary. Our 2012 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	**2012**			
Eagle Ford Project	$ 160			
Spraberry Area Pipeline Projects	75			
Mississippian Lime Pipeline	60			
PAA Natural Gas Storage (multiple projects)	58			
Rainbow II Pipeline	50			
Bakken North	50			
Ross Rail Project	45			
St. James Phase IV	40			
Shafter Expansion	40			
Gardendale Gathering System	40			
Yorktown Terminal Project	35			
BP NGL Acquisition Related Projects	30			
Dollard Custom Treating & Truck Terminal	25			
Other projects (1)	142			
	$ 850			
Potential Adjustments for Timing/Scope Refinement (2) (3)	-	$50	+	$100
Total Projected Expansion Capital Expenditures	$	800	to	$ 950
Maintenance Capital	$	130	to	$ 150

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2011.

(2) Potential variation to current capital costs estimates may result from changes to project design, final cost of materials and labor and timing of incurrence of costs due to uncontrollable factors such as regulatory approvals and weather.

(3) Amounts include preliminary forecasts for the BP NGL acquisition with an assumed closing date of April 1, 2012. Such forecast is preliminary and subject to change.

Distributions to our 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. On February 14 , 2012, we paid a quarterly distribution of $1.025 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 7.0%. See Note 5 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. “Market for Registrant’s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities—Cash Distribution Policy” for additional discussion on distributions.

Upon closing of the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due it as incentive distributions. The final $1 million of incentive distribution reductions related to these acquisitions was applied to our November 2011 distribution.

Beginning with the first distribution paid after closing the BP NGL acquisition, which is anticipated to occur in the second quarter of 2012, our general partner has agreed to reduce the amount of its incentive distributions by $15 million per year for two years and $10 million per year thereafter. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL acquisition.

Distributions to noncontrolling interests. We paid approximately $40 million and $10 million for distributions to our noncontrolling interests during the years ended December 31, 2011 and 2010, respectively. These amounts represent distributions paid on interests in PNG and SLC that are not owned by us.

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. We are, however, 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.

Contingencies

For a discussion of contingencies that may impact us, 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 five 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 purchases on the one hand and sales and future delivery obligations on the other. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. 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 entities that we deem creditworthy or who have provided credit support we consider adequate.

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, 2011 (in millions):

	2012	2013	2014	2015	2016	2017 and Thereafter	Total
Long-term debt, including current maturities and related interest payments[1]	$ 780	$ 516	$ 252	$ 793	$ 665	$ 4,768	$ 7,774
Leases [2]	71	55	47	41	33	292	539
Other obligations[3]	199	71	31	24	14	102	441
Pending BP NGL acquisition[4]	1,670	—	—	—	—	—	1,670
Subtotal	2,720	642	330	858	712	5,162	10,424
Crude oil, natural gas, LPG and other purchases[5]	4,325	558	243	131	101	25	5,383
Total	$ 7,045	$ 1,200	$ 573	$ 989	$ 813	$ 5,187	$ 15,807

(1) Includes debt service payments, interest payments due on our senior notes, interest payments and the commitment fee on the PNG credit agreement and the commitment fee on our PAA credit facilities. Although there is an outstanding balance on our PAA credit facilities at December 31, 2011, 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 (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks and railcars used in our gathering activities.

(3) Includes (i) other long-term liabilities, (ii) storage and transportation agreements and (iii) commitments related to our capital expansion projects. Excludes a non-current liability of approximately $114 million related to derivative activity included in Crude oil, natural gas, LPG and other purchases.

(4) In December 2011 we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company for total consideration of approximately $1.67 billion with an expected closing to occur during the second quarter of 2012. The closing of this acquisition is subject to a variety of conditions, including the receipt of various regulatory approvals.

(5) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2011. The actual physical volume purchased and actual settlement prices will 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 supply and logistics activities, 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, 2011 and 2010, we had outstanding letters of credit of approximately $33 million and $75 million, respectively.

Off-Balance Sheet Arrangements

We have no off-balance sheet arrangements as defined by Item 303 of Regulation S-K.

Investments in Unconsolidated Entities

We have invested in entities that are not consolidated in our financial statements. Certain of these entities are borrowers under credit facilities. We are neither a co-borrower nor a guarantor under any such facilities. We may elect at any time to make additional capital contributions to any of these entities. The following table sets forth selected information regarding these entities as of December 31, 2011 (unaudited, dollars in millions):

Entity	Type of Operation	Our Ownership Interest	Total Entity Assets	Total Cash and Restricted Cash	Total Entity Debt
Settoon Towing, LLC	Barge Transportation Services	50%	$ 170	$ —	$ 128
White Cliffs Pipeline, LLC	Crude Oil Pipeline	34%	$ 284	$ 4	$ —
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 27	$ 3	$ —
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 19	$ 3	$ —

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

We are exposed to various market risks, including volatility in (i) commodity prices for crude oil, refined products, natural gas and LPG, (ii) interest rates and (iii) currency exchange rates. Our policy is to use derivative instruments only for risk management purposes. We use various derivative instruments to manage such risks and, in certain circumstances, to realize incremental margin during volatile market conditions. Our risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring NYMEX, IntercontinentalExchange ("ICE") and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. We have a risk management function that has direct responsibility and authority for our risk policies, related controls around commercial activities and procedures and certain aspects of corporate risk management. Our risk management function also approves all new risk management strategies through a formal process. The following discussion addresses each category of risk.

Commodity Price Risk

We use derivative instruments to hedge our exposure to price fluctuations with respect to crude oil, refined products, natural gas and LPG in storage, and anticipated purchases and sales of these commodities. The derivative instruments utilized to manage our commodity price risk consist of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions. Our policy is (i) to purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not to acquire and hold physical inventory, futures contracts or other derivatives products for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

Although we seek to maintain positions that are substantially balanced, we purchase crude oil, refined products and LPG from thousands of locations and may experience net unbalanced positions as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions and other uncontrollable events. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time.

The fair value of our commodity derivatives and the change in fair value that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil:			
Futures contracts	$ 14	$ 21	$ (21)
Swaps and options contracts	75	$ (14)	$ 16
LPG and other:			
Swaps and options contracts	4	$ (21)	$ 21
Total fair value	$ 93		

The fair value of our exchange-traded derivatives is based on quoted market prices obtained from the NYMEX or ICE. The fair value of our over-the-counter swaps and options contracts is estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. See Note 6 to our Consolidated Financial Statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

We use both fixed and variable rate debt, and are exposed to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus not subject to interest rate risk. The majority of our variable rate debt at December 31, 2011, approximately $0.5 billion (including $150 million of interest rate derivatives that swap fixed rate debt for floating), is short-term debt and is subject to interest rate re-sets, which range from a week to three months. The average interest rate of 2.0% is based upon rates in effect during the year ended December 31, 2011. The fair value of our interest rate derivatives is an unrealized loss of approximately $137 million as of December 31, 2011. A 10% increase in the forward LIBOR curve as of December 31, 2011 would result in an increase of approximately $35 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2011 would result in a decrease of approximately $35 million to the fair value of our interest rate derivatives. See Note 6 to our Consolidated Financial Statements for a discussion of our interest rate risk hedging activities.

Currency Exchange Rate Risk

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. The fair value of these instruments is an unrealized gain of approximately $1 million as of December 31, 2011. A 10% increase or decrease in the exchange rate (CAD-to-USD) would result in immaterial changes to the fair value of our foreign currency derivatives. See Note 6 to our Consolidated Financial Statements for a discussion of our currency exchange rate risk hedging.

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

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

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

None.

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

Disclosure Controls and Procedures

We maintain written "disclosure controls and procedures," which we refer to as our "DCP." Our DCP is designed to ensure that (i) information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the "Exchange Act") is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) such 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 the end of the period covered by this report, 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.

Internal Control over Financial Reporting

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 GAAP. 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, 2011. See Management's Report on Internal Control Over Financial Reporting on page F-2 of our Consolidated Financial Statements.

Although we have made various enhancements to our controls, there have been no changes in our internal control over financial reporting during the period covered by this report that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Certifications

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.

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

There was no information that was required to be disclosed in a report on Form 8-K during the fourth quarter of 2011 that has not previously been reported.