PART II

Item 5. *Market for Registrant's Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities*

Our Class A shares are listed and traded on the New York Stock Exchange ("NYSE") under the symbol "PAGP." As of February 20, 2014, there were approximately 18,100 record holders and beneficial owners (held in street name). As of March 6, 2014, there were 135,833,637 Class A shares outstanding and the closing market price for our Class A shares was $28.04 per share.

The following table sets forth high and low sales prices for our Class A shares and the cash distribution declared per Class A share for the periods indicated:

	Class A share Price Range		Cash
	High	Low	Distribution [1] [2]
4th Quarter 2013 [3]	$ 27.04	$ 21.50	$ 0.12505

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

(2) The distribution paid for the fourth quarter of 2013 was prorated for the period from October 21, 2013 (the date of closing of our IPO) through December 31, 2013, which corresponds to a distribution of $0.15979 per Class A share before proration, assuming our ownership of AAP for the full fourth quarter of 2013.

(3) Our Class A shares did not commence trading on the NYSE until October 2013.

Our Class B shares are not listed or traded on any stock exchange.

Our Class A shares may be used as a form of compensation to our employees and directors. 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."

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

Use of Proceeds from Sale of Securities

On October 16, 2013, we commenced the IPO of our Class A shares pursuant to our Registration Statement on Form S-1, Commission File No. 333-190227, which was declared effective by the Securities and Exchange Commission on October 15, 2013. Barclays Capital Inc., Goldman, Sachs & Co., JP Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., UBS Securities LLC and Wells Fargo Securities, LLC acted as joint book-running managers of the offering.

In October 2013, we issued 132,382,094 Class A shares, which included 4,382,094 Class A shares issued pursuant to partial exercise of the underwriters' over-allotment option, at a price per share of $22.00. After deducting underwriting discounts and commissions of approximately $87 million paid to the underwriters, estimated offering expenses of approximately $5 million, the net proceeds from the IPO were approximately $2.8 billion. We distributed all of the net proceeds to the existing owners of AAP who sold a portion of their interests in AAP in connection with the offering.

Cash Distribution Policy

Our partnership agreement requires that, within 55 days after the end of each quarter, we distribute all of our available cash to Class A shareholders of record on the applicable record date. Available cash generally means, for any quarter ending prior to liquidation, all cash on hand at the date of determination of available cash for the distribution in respect of such quarter (including expected distributions from AAP in respect of such quarter), less the amount of cash reserves established by our general partner, which will not be subject to a cap, to:

- comply with applicable law or any agreement binding upon us or our subsidiaries (exclusive of PAA and its subsidiaries);
- provide funds for distributions to shareholders;
- provide for future capital expenditures, debt service and other credit needs as well as any federal, state, provincial or other income tax that may affect us in the future;
- permit us to pay a ratable amount to AAP as necessary to permit AAP to make required capital contributions to PAA to maintain PAA GP's 2% general partner interest upon the issuance of additional partnership securities by PAA; or
- provide for the proper conduct of our business;

As of December 31, 2013, our only cash-generating assets consisted of 133,833,637 AAP units, which represent a 22.1% limited partner interest in AAP. AAP currently receives all of its cash flows from its direct ownership of all of PAA's incentive distribution rights and its indirect ownership of the 2% general partner interest in PAA. Therefore, our cash flow and resulting ability to make distributions will be completely dependent upon the ability of PAA to make distributions to AAP in respect of those partnership interests. The actual amount of cash that PAA, and correspondingly AAP, will have available for distribution will primarily depend on the amount of cash PAA generates from its operations. Also, under the terms of the agreements governing AAP and PAA's debt, they 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 Agreements, PAA Commercial Paper Program and Indentures."

Although not required to do so, in response to past requests by PAA management in connection with PAA's acquisition activities, AAP has, from time to time, agreed to reduce the amounts due to it as incentive distributions. Such modifications were implemented with a view toward enhancing PAA's competitiveness for such acquisitions and managing the overall cost of equity capital while achieving an appropriate balance between short-term and long-term accretion to PAA's limited partners and the holders of its general partner interest and IDRs. AAP agreed to reduce the amount of its incentive distribution by $3.75 million per quarter for distributions paid during 2013, $6.75 million for the distribution paid in February 2014, $5.5 million per quarter thereafter through November 2015, $5.0 million per quarter in 2016 and $3.75 million per quarter thereafter. These reductions were agreed to in connection with the BP NGL Acquisition and the completion of the PNG Merger on December 31, 2013. See Note 3 to our Consolidated Financial Statements for further discussion of the BP NGL Acquisition. See Note 1 to our Consolidated Financial Statements for further discussion of the PNG Merger.

Issuer Purchases of Equity Securities

We did not repurchase any of our Class A shares during the fourth quarter of 2013, and we do not have any announced or existing plans to repurchase any of our Class A shares.

Item 6. *Selected Financial Data*

The following tables set forth selected historical consolidated financial and other information for PAGP as of the dates and for the periods indicated. The selected consolidated statements of operations data for the year ended December 31, 2013 include results attributable to PAGP from October 21, 2013 (the date of closing PAGP's IPO) through December 31, 2013, plus results for Plains All American GP LLC ("GP LLC"), the predecessor entity to PAGP, prior to October 21, 2013.

The selected historical statements of operations and cash flow data for the years ended December 31, 2013, 2012 and 2011 and balance sheet data as of December 31, 2013 and 2012 is derived from the audited financial statements of PAGP (and GP LLC as discussed above) included elsewhere in this document. The selected historical statements of operations and cash flow data for the year ended December 31, 2010 and 2009 and the balance sheet data as of December 31, 2011, 2010 and 2009 are derived from the unaudited financial statements of GP LLC that are not included elsewhere in this document.

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,				
	2013	2012	2011	2010	2009
	(in millions, except for per share data)				
Statement of operations data:					
Total revenues	$ 42,249	$ 37,797	$ 34,275	$ 25,893	$ 18,520
Net income	$ 1,374	$ 1,118	$ 987	$ 501	$ 568
Net income attributable to PAGP	$ 15	$ 3	$ 2	$ 2	$ 1
Per share data:					
Basic and diluted net income per Class A share [(1)]	$ 0.10	N/A	N/A	N/A	N/A
Balance sheet data (at end of period):					
Total assets	$ 21,453	$ 19,259	$ 15,414	$ 13,734	$ 12,388
Long-term debt	$ 7,230	$ 6,520	$ 4,720	$ 4,831	$ 4,342
Total debt	$ 8,343	$ 7,606	$ 5,406	$ 6,161	$ 5,416
Partners' capital/Members' equity:					
Partners' capital/Members' equity (excluding noncontrolling interests)	$ 1,035	$ —	$ —	$ —	$ —
Noncontrolling interests	7,244	6,968	5,794	4,391	3,977
Total Partners' capital/Members' equity	$ 8,279	$ 6,968	$ 5,794	$ 4,391	$ 3,977
Other data:					
Net cash provided by operating activities	$ 1,948	$ 1,232	$ 2,357	$ 248	$ 357
Net cash used in investing activities	$ (1,653)	$ (3,392)	$ (2,020)	$ (851)	$ (686)
Net cash provided by/(used in) financing activities	$ (274)	$ 2,159	$ (337)	$ 613	$ 348
Capital expenditures:					
Acquisitions	$ 19	$ 2,286	$ 1,404	$ 407	$ 393
Internal growth projects	$ 1,622	$ 1,185	$ 531	$ 355	$ 379
Maintenance	$ 176	$ 170	$ 120	$ 93	$ 81

	Year Ended December 31,				
	2013	2012	2011	2010	2009
Volumes (2)(3)					
Transportation segment (average daily volumes in thousands of barrels per day):					
Tariff activities	3,595	3,373	2,942	2,889	2,836
Trucking	117	106	105	97	85
Transportation segment total	3,712	3,479	3,047	2,986	2,921
Facilities segment:					
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	90	70	61	56
Rail load / unload volumes (average volumes in thousands of barrels per day)	221	—	—	—	—
Natural gas storage (average monthly capacity in billions of cubic feet)	96	84	71	47	26
NGL fractionation (average volumes in thousands of barrels per day)	96	79	14	14	15
Facilities segment total (average monthly volumes in millions of barrels)	120	106	82	70	61
Supply and Logistics segment (average daily volumes in thousands of barrels per day):					
Crude oil lease gathering purchases	859	818	742	620	612
NGL sales	215	182	103	96	105
Waterborne cargos	4	3	21	68	55
Supply and Logistics segment total	1,078	1,003	866	784	772

(1) Attributable to post-IPO period, October 21, 2013 through December 31, 2013.

(2) Volumes associated with acquisitions represent total volumes (attributable to our interest) for the number of days or months we actually owned the assets divided by the number of days or months in the year.

(3) Facilities segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) 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 (iv) NGL fractionation 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, including periods prior to the closing of our IPO on October 21, 2013. Such analysis should be read in conjunction with our historical consolidated financial statements and accompanying notes. For ease of reference, we refer to the historical results of Plains All American GP LLC (“GP LLC”) prior to our IPO as being “our” historical financial results. Unless the context otherwise requires, references to “we,” “us,” “our,” and “PAGP” are intended to mean the business and operations of PAGP and its consolidated subsidiaries since October 21, 2013. When used in the historical context (i.e. prior to October 21, 2013), these terms are intended to mean the business and operations of GP LLC and its consolidated subsidiaries.

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
- Recent Accounting Pronouncements
- Results of Operations
- Outlook
- Liquidity and Capital Resources

Executive Summary

Company Overview

We are a Delaware limited partnership formed on July 17, 2013 to own an interest in the general partner and incentive distribution rights ("IDRs") of Plains All American Pipeline, L.P ("PAA"), a publicly traded Delaware limited partnership. Although we were formed as a limited partnership, we have elected to be taxed as a corporation for United States federal income tax purposes. As of December 31, 2013, we owned a 22.1% limited partner interest in AAP, and the remaining limited partner interests in AAP continue to be held by the owners of AAP immediately prior to our IPO (the "Legacy Owners"). AAP is a Delaware limited partnership that directly owns all of PAA's incentive distribution rights and indirectly owns the 2% general partner interest in PAA. AAP is the sole member of PAA GP LLC ("PAA GP"), a Delaware limited liability company that directly holds the 2% general partner interest in PAA.

Through a series of transactions prior to our IPO with our general partner and the owners of GP LLC, a Delaware limited liability company formed on May 2, 2001 that manages the business and affairs of PAA and AAP, GP LLC's general partner interest in AAP became a non-economic interest, and we became the owner of a 100% managing member interest in GP LLC. Since we are the managing member of and control GP LLC, which in turn effectively controls PAA we reflect our ownership in PAA, as well as its subsidiaries, on a consolidated basis in accordance with generally accepted accounting principles. Accordingly, our financial results are combined with those of GP LLC and PAA as well as with their subsidiaries. As such, our results of operations as discussed below do not differ materially from the results of operations of PAA.

PAA owns and operates midstream energy infrastructure and provides logistics services for crude oil, natural gas liquids ("NGL"), natural gas and refined products. The term NGL includes ethane and natural gasoline products as well as products commonly referred to as liquefied petroleum gas ("LPG") such as propane and butane. When used in this Form 10-K, NGL refers to all NGL products including LPG. PAA owns an extensive network of pipeline transportation, terminalling, storage, and gathering assets in key crude oil and NGL producing basins and transportation corridors and at major market hubs in the United States and Canada. On average, PAA handles over 3.5 million barrels per day of crude oil and NGL on its pipelines.

Overview of Operating Results, Capital Investments and Significant Activities

During 2013, net income was approximately $1.374 billion, as compared to net income of approximately $1.118 billion recognized during 2012. Major items impacting the favorable performance between periods include contributions from the USD Rail Terminal and BP NGL Acquisitions, which were completed in December 2012 and April 2012, respectively, incremental fee-based contributions associated with acquisition and expansion capital invested in our Transportation and Facilities segments and favorable unit margins in our Supply and Logistics segment.

The favorable unit margins in the Supply and Logistics segment were driven by our NGL marketing operations, which benefited from improved market conditions and higher demand, as well as additional sales volumes related to the BP NGL Acquisition noted above. However, such results were partially offset by the impact of less favorable crude oil market conditions, particularly narrower crude oil differentials during much of 2013.

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Other significant items impacting the comparison to 2012 include:

- Decreased depreciation and amortization expense, largely driven by one-time asset impairment charges of approximately $168 million recognized during the comparative 2012 period; and
- Increased income tax expense resulting from an increased proportion of earnings subject to Canadian federal and provincial taxes, primarily driven by the stronger performance from our existing operations and operations related to the BP NGL Acquisition.

Acquisitions and Internal Growth Projects

We completed a number of acquisitions and capital expansion projects in 2013, 2012 and 2011 that have impacted our results of operations. The following table summarizes our capital expenditures for acquisitions, internal growth projects and maintenance capital for the periods indicated (in millions):

	For the Year Ended December 31,		
	2013	2012	2011
Acquisition capital [1]	$ 19	$ 2,286	$ 1,404
Internal growth projects	1,622	1,185	531
Maintenance capital	176	170	120
	$ 1,817	$ 3,641	$ 2,055

(1) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

Acquisitions

Acquisitions are financed using a combination of equity and debt, including borrowings under 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 2013, 2012 and 2011 is set forth in the table below (in millions):

Acquisition	Effective Date	Acquisition Price	Operating Segment
2013 Total [1]	09/01/2013	$ 19	Transportation
BP NGL Acquisition [2]	04/01/2012	$ 1,633	Transportation, Facilities and Supply and Logistics
US Development Group Crude Oil Rail Terminals	12/13/2012	503	Facilities
Other	Various	150	Transportation, Facilities and Supply and Logistics
2012 Total		$ 2,286	
Southern Pines	02/09/2011	$ 765	Facilities
Gardendale Gathering System	11/29/2011	349	Transportation
Western Pipeline and Storage Assets	12/29/2011	220	Facilities and Transportation
Other	Various	70	Transportation, Facilities and Supply and Logistics
2011 Total		$ 1,404	

(1) Excludes the PNG Merger completed on December 31, 2013, as we historically consolidated PNG into our financial statements for financial reporting purposes in accordance with GAAP. As consideration for the PNG Merger, PAA issued approximately 14.7 million of its common units with a value of approximately $760 million.

(2) Total BP NGL Acquisition purchase price was approximately $1.683 billion. A cash deposit of $50 million was paid during 2011 and is reflected in 'Other' in the 2011 Total in the table above.

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Internal Growth Projects

Our 2013 projects included the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our 2013, 2012 and 2011 projects (in millions):

Projects	2013	2012	2011
Mississippian Lime Pipeline [(1)]	$ 163	$ 54	$ —
Gulf Coast Pipeline [(1)]	125	13	—
Rainbow II Pipeline	124	79	44
Yorktown Terminal Projects	114	39	—
Eagle Ford Area Pipeline Projects [(1) (2)]	86	88	2
Rail Terminal Projects [(4)]	83	41	27
White Cliffs Expansion [(5)]	73	1	—
Fort Saskatchewan Facility Expansions	73	—	—
Cactus Pipeline [(1)]	64	—	—
Eagle Ford JV Project [(1) (3)]	60	132	18
Spraberry Area Pipeline Projects [(1)]	51	91	—
St. James Expansions [(1)]	51	46	4
Western Oklahoma Pipeline [(1)]	50	—	—
Natural Gas Storage (multiple projects) [(1)]	45	61	89
Cushing Terminal Expansions [(1)]	38	31	41
Gulf Coast Gas Processing Facility Enhancements	36	—	—
Shafter Expansion	28	21	2
Other projects	358	488	304
Total	$ 1,622	$ 1,185	$ 531

(1) These projects will continue into 2014. See "—Liquidity and Capital Resources—Acquisitions, Capital Expenditures and Distributions Paid to Our Class A Shareholders and Noncontrolling Interests—2014 Capital Expansion Projects."

(2) Includes pipeline, tankage and condensate stabilization.

(3) Includes net expenditures associated with the formation of Eagle Ford Pipeline LLC in 2012, as well as subsequent contributions related to our 50% interest.

(4) Includes Manitou, ND, Bakersfield, CA, Tampa, CO, and Van Hook, ND rail projects.

(5) Represents contributions related to our 35.7% investment interest in the White Cliffs Pipeline.

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-indexed 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 estimates. 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, 2013, we estimate that approximately 1% and 2% of annual revenues and cost of sales were recorded using sales and purchase estimates, respectively. Accordingly, a hypothetical variance of 10% from both of these estimates, either up or down in tandem, would impact annual revenues, cost of sales, operating income and net income by 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 2013, 2012 or 2011. See Note 8 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 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. See Note 11 to our Consolidated Financial Statements for a discussion regarding derivatives and risk management activities.

Accruals and Contingent Liabilities. We record accruals or liabilities including, but not limited to, environmental remediation and governmental penalties, asset retirement obligations, equity-indexed compensation plan accruals (as further discussed below), bonus accruals 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 hypothetical 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 $15 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-Indexed Compensation Plan Accruals. We accrue compensation expense (referred to herein as equity-indexed compensation expense) for outstanding equity-indexed compensation awards. Under GAAP, we are required to estimate the fair value of our outstanding equity-indexed compensation awards and recognize that fair value as compensation expense over the service period. For equity-indexed compensation awards that contain a performance condition, the fair value of the 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-indexed compensation awards.

We recognized total compensation expense of approximately $116 million, $101 million and $110 million in 2013, 2012 and 2011, respectively, related to awards granted under our various equity-indexed compensation plans. We cannot provide assurance that the actual fair value of our equity-indexed compensation awards will not vary significantly from estimated amounts. See Note 15 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.

We periodically evaluate property and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. 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.

During 2013, 2012 and 2011, we recognized losses on impairments of long-lived assets of approximately $20 million, $168 million and $5 million, respectively. The impairments recognized in 2013 and 2011 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 some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets. See Note 6 to our Consolidated Financial Statements for further discussion regarding impairments.

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 consolidated 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 18 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 PAGP.

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 our 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. 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.

The following table sets forth an overview of our consolidated financial results calculated in accordance with GAAP (in millions, except for per share amounts):

	For the Twelve Months Ended December 31, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 $	%	2012-2011 $	%
Transportation segment profit	$ 729	$ 710	$ 555	$ 19	3%	$ 155	28%
Facilities segment profit	616	482	358	134	28%	124	35%
Supply and Logistics segment profit	822	753	647	69	9%	106	16%
Total segment profit	2,167	1,945	1,560	222	11%	385	25%
Unallocated general and administrative expenses	(1)	—	—	(1)	N/A	—	—%
Depreciation and amortization	(378)	(483)	(250)	105	22%	(233)	(93)%
Interest expense	(309)	(295)	(259)	(14)	(5)%	(36)	(14)%
Other income/(expense), net	1	6	(19)	(5)	(83)%	25	132%
Income tax expense	(106)	(55)	(45)	(51)	(93)%	(10)	(22)%
Net income	1,374	1,118	987	256	23%	131	13%
Net income attributable to noncontrolling interests	(1,359)	(1,115)	(985)	(244)	(22)%	(130)	(13)%
Net income attributable to PAGP	$ 15	$ 3	$ 2	$ 12	400%	$ 1	50%
Net income attributable to PAGP:							
Basic and diluted net income per Class A share [1]	$ 0.10	N/A	N/A				
Basic and diluted weighted average number of Class A shares outstanding [1]	132	N/A	N/A				

(1) Attributable to post-IPO period, October 21, 2013 through December 31, 2013.

Transportation Segment

Our Transportation segment operations generally consist of fee-based activities associated with transporting crude oil and NGL on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and other 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, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 $	%	2012-2011 $	%
Revenues							
Tariff activities	$ 1,293	$ 1,232	$ 1,005	$ 61	5%	$ 227	23%
Trucking	205	184	160	21	11%	24	15%
Total transportation revenues	1,498	1,416	1,165	82	6%	251	22%
Cost and Expenses							
Trucking costs	(147)	(134)	(115)	(13)	(10)%	(19)	(17)%
Field operating costs (excluding equity-indexed compensation expense)	(528)	(468)	(387)	(60)	(13)%	(81)	(21)%
Equity-indexed compensation expense - operations	(18)	(16)	(14)	(2)	(13)%	(2)	(14)%
Segment general and administrative expenses [2] (excluding equity-indexed compensation expense)	(101)	(96)	(69)	(5)	(5)%	(27)	(39)%
Equity-indexed compensation expense - general and administrative	(39)	(30)	(38)	(9)	(30)%	8	21%
Equity earnings in unconsolidated entities	64	38	13	26	68%	25	192%
Segment profit	$ 729	$ 710	$ 555	$ 19	3%	$ 155	28%
Maintenance capital	$ 123	$ 108	$ 86	$ (15)	(14)%	$ (22)	(26)%
Segment profit per barrel	$ 0.54	$ 0.56	$ 0.50	$ (0.02)	(4)%	$ 0.06	12%

Average Daily Volumes (in thousands of barrels per day) [3]	Year Ended December 31, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 Volumes	2013-2012 %	2012-2011 Volumes	2012-2011 %
Tariff activities							
Crude Oil Pipelines							
All American	40	33	35	7	21%	(2)	(6)%
Bakken Area Systems	131	130	130	1	1%	—	—%
Basin / Mesa	718	696	566	22	3%	130	23%
Capline	151	146	160	5	3%	(14)	(9)%
Eagle Ford Area Systems	102	23	5	79	343%	18	360%
Line 63 / Line 2000	113	128	114	(15)	(12)%	14	12%
Manito	46	57	66	(11)	(19)%	(9)	(14)%
Mid-Continent Area Systems	281	271	218	10	4%	53	24%
Permian Basin Area Systems	581	461	404	120	26%	57	14%
Rainbow	124	145	142	(21)	(14)%	3	2%
Rangeland	60	62	59	(2)	(3)%	3	5%
Salt Lake City Area Systems	131	149	146	(18)	(12)%	3	2%
South Saskatchewan	51	60	52	(9)	(15)%	8	15%
White Cliffs	23	18	13	5	28%	5	38%
Other	725	703	730	22	3%	(27)	(4)%
NGL Pipelines							
Co-Ed	56	44	—	12	27%	44	N/A
Other	194	131	—	63	48%	131	N/A
Refined Products Pipelines	68	116	102	(48)	(41)%	14	14%
Tariff activities total	3,595	3,373	2,942	222	7%	431	15%
Trucking	117	106	105	11	10%	1	1%
Transportation segment total	3,712	3,479	3,047	233	7%	432	14%

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

(2) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(3) Volumes associated with acquisitions represent total volumes (attributable to our interest) 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. Revenue 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. Our Transportation segment results were impacted by the following for the years ended December 31, 2013, 2012 and 2011:

- North American Crude Oil Production and Related Expansion Projects — For the year ended December 31, 2013, the favorable volume and revenue variances experienced were primarily due to increased producer drilling activities as well as the completion of certain of our expansion projects, most notably on our Permian Basin and Eagle Ford Area Systems and our Basin and Mesa pipelines. The Permian Basin Area Systems also benefited from increased movements to a new third-party pipeline connected to Gulf Coast markets. We estimate that increased production combined with our phased-in expansion projects increased revenues by approximately $40 million for the annual 2013 period over the comparable 2012 period.

Increased producer drilling activities and phased-in expansion projects also resulted in favorable volume and revenue variances for the year ended December 31, 2012 over the comparative 2011 period, most notably on our Basin and Mesa pipelines and Permian Basin and Mid-Continent Area Systems. We estimate that increased production combined with our phased-in expansion projects increased revenues by approximately $50 million for the annual 2012 period over the comparable 2011 period.

- Rate Changes — Revenues on our pipelines are impacted by various rate changes that may occur during the period. These rate changes primarily include the indexing of rates on our FERC regulated pipelines, rate increases or decreases on our intrastate and Canadian pipelines or other negotiated rate changes. The upward indexings effective July 1, 2011, 2012 and 2013 favorably impacted revenues on a majority of our FERC regulated pipelines. However, during the third quarter of 2013, as a result of market factors, we lowered our tariff rates on certain of our FERC regulated pipelines relative to 2012 rates, which partially offset the favorable impact of the upward indexing effective July 1, 2013. Revenues for both the 2013 and 2012 periods were also favorably impacted by increasing tariff rates on certain of our non-FERC regulated pipelines.

  We estimate that the collective impact of these rate changes increased revenues by approximately $50 million for 2013 compared to 2012, and by approximately $45 million for 2012 compared to 2011.

- BP NGL Acquisition Assets —We acquired pipelines through the BP NGL Acquisition completed on April 1, 2012. These assets contributed approximately $27 million of additional tariff revenues for the year ended December 31, 2013 over the year ended December 31, 2012, which was primarily related to the benefit from a full period of ownership of these assets (as we only owned the assets for nine months of 2012). This increase excludes the unfavorable impacts related to decreased tariff rates and weather-related downtime on our Co-Ed pipeline, as discussed elsewhere in this section.

  The BP NGL Acquisition assets generated tariff revenues of approximately $89 million and increased volumes by approximately 175,000 barrels per day for the year ended December 31, 2012 over the year ended December 31, 2011.

- Loss Allowance Revenue — As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to 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 decreased by approximately $23 million for 2013 compared to 2012 primarily due to a lower average realized price per barrel (including the impact of gains and losses from derivative-related activities) and lower volumes. The loss allowance revenue increased by approximately $13 million for 2012 compared to 2011 primarily due to higher loss allowance volumes, partially offset by a lower average realized price per barrel compared to 2011 (including the impact of losses from derivative-related activities).

- Weather-Related Downtime — During the second and third quarters of 2013, our Rangeland, South Saskatchewan and Co-Ed pipelines in Canada were shut down due to high river flow rates and flooding in the surrounding area. We estimate that the downtime on these pipelines negatively impacted revenues and volumes by approximately $15 million to $20 million and 15,000 to 20,000 barrels per day, respectively, for the year ended December 31, 2013.

- Rail Impact — Volumes for the 2013 period, primarily on our Manito and Rainbow pipelines and certain pipelines included in our Bakken Area Systems, were unfavorably impacted by producer decisions to deliver more crude oil to rail loading facilities in the area. We estimate that the impact to revenues was approximately $20 million for the year ended December 31, 2013 and that volumes decreased by approximately 25,000 to 30,000 barrels per day for the period. Although to a lesser extent, volumes in the 2012 period compared to 2011 were also unfavorably impacted by producer decisions to deliver more crude oil to rail loading facilities, primarily on our Manito pipeline.

- 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 2013 and 2012 were $1.03 CAD: $1.00 USD and $1.00 CAD: $1.00 USD, respectively. Therefore, revenues from our Canadian pipeline systems and trucking operations were unfavorably impacted by approximately $13 million for 2013 compared to 2012 due to the depreciation of the Canadian dollar relative to the U.S. dollar. The translation of revenues and expenses from our Canadian based subsidiaries did not have a significant impact on our Transportation segment results in 2012 as compared to 2011.

Additional noteworthy volume and revenue variances for the year ended December 31, 2013 compared to 2012 include (i) increased volumes and revenues on our All American pipeline due to higher production levels in 2013 coupled with lower maintenance activities at the production facilities in 2013 compared to 2012, (ii) decreases on the Salt Lake City Area Systems and our Line 63 and Line 2000 pipelines due to refinery maintenance issues and lower refinery demand for pipeline barrels; however, revenues on Line 63 pipeline were consistent with 2012 results due to movements on higher tariff segments, (iii) increased volumes and revenues on our Mid-Continent Area Systems primarily due the startup of the Mississippian Lime pipeline, which was placed in service in August 2013, (iv) increased trucking activity due to increased demand for production transported to rail terminals and hauls from pipeline disruptions and (v) decreased volumes and revenues on our Refined Products Pipelines primarily due to the sale of these assets in the third and fourth quarters of 2013.

Additional noteworthy volume and revenue variances on our individual pipeline systems for the year ended December 31, 2012 include (i) increases on the Eagle Ford Area Systems resulting from the Gardendale Gathering System acquired in November 2011 and (ii) favorable volume and revenue variances in 2012 on our Rainbow pipeline due to downtime in 2011 as a result of a pipeline release in April of 2011 and rate increases in 2012, partially offset by the impact of a third-party competitor pipeline that was placed into service in the third quarter of 2011.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expense) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 primarily due to (i) higher environmental response, remediation and related repair expenses associated with pipeline releases of approximately $21 million, (ii) higher integrity management expenses associated with smart pigging and other integrity work, (iii) higher payroll costs, primarily due to the BP NGL Acquisition and increased headcount and (iv) approximately $4 million of cost incurred associated with the testing of certain lines that we considered bringing back into service. Excluding the impacts of the environmental response and remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during the comparable annual periods.

Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2012 compared to the year ended December 31, 2011 consistent with the overall growth in segment volumes and remained relatively constant on a per barrel basis during each of those periods. Operating costs were also impacted by approximately $15 million of environmental remediation expenses associated with the Rangeland Pipeline release, which occurred in the second quarter of 2012, and approximately $11 million of environmental remediation expenses associated with the Rainbow Pipeline release, which occurred in the second quarter of 2011.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 over the year ended December 31, 2012 due to the continued overall growth of the segment and legal fees incurred in connection with the sale of certain of our refined products pipelines in 2013.

The increase in general and administrative expenses (excluding equity-indexed compensation expenses) during the year ended December 31, 2012 over the year ended December 31, 2011 was due to non-recurring costs associated with the closing and integration of the BP NGL Acquisition and ongoing administrative costs associated with this acquisition, as well as the continued overall growth of the segment.

Equity-Indexed Compensation Expenses. A majority of our equity-indexed compensation awards (including the AAP Management Units) contain performance conditions contingent upon PAA 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 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, 2013 and 2012, we determined that PAA distribution levels of $2.75 and $2.45 per unit, respectively, were probable of occurring. Furthermore, a change in PAA's unit price impacts the fair value of our liability-classified awards. See Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

On a consolidated basis, equity-indexed compensation expense increased by approximately $15 million for the year ended December 31, 2013 over the year ended December 31, 2012 primarily due to the following: (i) a more significant impact of the increase in PAA's unit price during the year ended December 31, 2013 compared to the impact of the increase during the year ended December 31, 2012, (ii) a greater number of units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012 and (iii) a higher average fair value per unit for those units deemed probable of vesting for the year ended December 31, 2013 compared to the year ended December 31, 2012. Equity-indexed compensation expense decreased by approximately $9 million for the year ended December 31, 2012 compared to the year ended December 31, 2011, primarily related to a less significant impact of the change in probability assessment as compared to 2011.

Equity Earnings in Unconsolidated Entities. The favorable variance in equity earnings in unconsolidated entities for the year ended December 31, 2013 compared to the year ended December 31, 2012 was largely due to (i) increased throughput on the Eagle Ford and White Cliffs pipelines as a result of increased production, as discussed above and (ii) increased capacity related to vessel additions and increased rates on services provided by Settoon Towing.

Equity earnings in unconsolidated entities increased for the year ended December 31, 2012 compared to the year ended December 31, 2011 due to increased volumes as a result of industry fundamentals, as noted above.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The increase in maintenance capital in 2013 compared to 2012 and in 2012 compared to 2011 is primarily due to increased investments on pipeline integrity projects.

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 NGL, as well as NGL fractionation and isomerization services and natural gas and condensate processing 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, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 $	2013-2012 %	2012-2011 $	2012-2011 %
Revenues	$ 1,075	$ 868	$ 605	$ 207	24%	$ 263	43%
Natural gas sales [2]	302	230	191	72	31%	39	20%
Storage related costs (natural gas related)	(16)	(22)	(22)	6	27%	—	—%
Natural gas costs [2]	(296)	(216)	(183)	(80)	(37)%	(33)	(18)%
Field operating costs (excluding equity-indexed compensation expense)	(362)	(289)	(165)	(73)	(25)%	(124)	(75)%
Equity-indexed compensation expense - operations	(2)	(2)	(2)	—	—%	—	—%
Segment general and administrative expenses [3] (excluding equity-indexed compensation expense)	(63)	(64)	(47)	1	2%	(17)	(36)%
Equity-indexed compensation expense - general and administrative	(22)	(23)	(19)	1	4%	(4)	(21)%
Segment profit	$ 616	$ 482	$ 358	$ 134	28%	$ 124	35%
Maintenance capital	$ 38	$ 49	$ 22	$ 11	22%	$ (27)	(123)%
Segment profit per barrel	$ 0.43	$ 0.38	$ 0.36	$ 0.05	13%	$ 0.02	6%

Volumes [4] [5]	For the Year Ended December 31, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 Volumes	2013-2012 %	2012-2011 Volumes	2012-2011 %
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	90	70	4	4%	20	29%
Rail load / unload volumes (average volumes in thousands of barrels per day)	221	—	—	221	N/A	—	N/A
Natural gas storage (average monthly capacity in billions of cubic feet)	96	84	71	12	14%	13	18%
NGL fractionation (average volumes in thousands of barrels per day)	96	79	14	17	22%	65	464%
Facilities segment total (average monthly volumes in millions of barrels)	120	106	82	14	13%	24	29%

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

(2) Natural gas sales and costs are primarily attributable to the activities performed by our natural gas storage commercial optimization group.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

(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 segment total is calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the year and divided by the number of months in the year; (iii) 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 (iv) NGL fractionation 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 costs, and volumes increased year-over-year for each comparative period 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:

- Rail Terminal Acquisition and Related Expansion Projects — The USD Rail Terminal Acquisition in December 2012 and rail-related internal growth projects completed during the latter portion of 2012 and 2013 expanded our rail loading and unloading fee-based activities. Rail load and unload activities contributed approximately $103 million and $22 million to the increase in total revenues for the years ended December 31, 2013 and 2012, respectively.

- NGL Storage, Fractionation and Gas Processing Activities —We acquired NGL storage facilities, fractionation plants and related assets through the BP NGL Acquisition completed in April 2012. These assets contributed approximately $87 million of aggregate revenues for the year ended December 31, 2013 over the year ended December 31, 2012, primarily due to the benefit from a full period of ownership of these assets in 2013 (as we only owned the assets for nine months of 2012), as well as from physical processing gains recognized primarily at our NGL fractionation facilities.

  For the year ended December 31, 2012, the BP NGL Acquisition assets contributed aggregate revenues of approximately $204 million, increased average monthly capacity of NGL storage by approximately 10 million barrels and increased average NGL fractionation throughput by approximately 65,000 barrels per day over the year ended December 31, 2011.

- Other Expansion Projects and Acquisitions — We estimate that expansion projects that were completed in phases throughout recent years at some of our major terminal locations favorably impacted revenues by approximately $22 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. Such projects included completed phases of expansions at our Cushing, Patoka, St. James and Yorktown terminals, new condensate stabilizers at our Gardendale site, and expansion of gas processing capacity at our facilities near the Gulf Coast. Partially offsetting the increased revenues from these expansions was reduced revenues from certain storage facilities in California and the East Coast due to decreased demand. While average monthly natural gas storage capacity increased during 2013 due to expansions of the Pine Prairie and Southern Pines facilities, decreased storage rates on contracts executed to replace expiring contracts on existing capacity largely offset incremental revenues from our natural gas storage activities.

  The completion of our Yorktown facility acquisition in December 2011 and expansion projects at our Cushing, Patoka and St. James terminals throughout 2011 and 2012 resulted in increased storage capacity and barge loading and receipt capability. We estimate that these activities increased our revenues by approximately $24 million on a combined basis for the year ended December 31, 2012 compared to the year ended December 31, 2011. Additionally, revenues and volumes for 2012 compared to 2011 were favorably impacted by the expansion of working gas capacity at PNG's Pine Prairie and Southern Pines facilities by approximately 17 Bcf in the aggregate during 2012.

Field Operating Costs. Field operating costs (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2013 compared to the year ended December 31, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal Acquisitions. A portion of the increase was also related to additional costs for integrity and other maintenance, particularly on the assets that were part of the BP NGL Acquisition.

The increase in field operating costs (excluding equity-indexed compensation expenses) during the year ended December 31, 2012 over the year ended December 31, 2011 was also primarily due to growth through acquisitions, primarily the BP NGL and Yorktown acquisitions.

General and Administrative Expenses. General and administrative expenses (excluding equity-indexed compensation expenses) increased during the year ended December 31, 2012 compared to the year ended December 31, 2011 due to growth associated with the BP NGL Acquisition as well as certain one-time costs during 2012 associated with integrating this acquisition.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased during 2013 as compared to 2012 and decreased during 2012 as compared to 2011. See the discussion regarding such variances under "—Transportation Segment" above. Also, see Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Maintenance Capital. Maintenance capital consists of capital expenditures for the replacement of partially or fully depreciated assets in order to maintain the operating and/or earnings capacity of our existing assets. The decrease in maintenance capital in 2013 from 2012 is primarily due to two major equipment replacement projects that occurred in 2012. These projects contributed to the overall increase in 2012 from 2011, along with growth from acquisitions and increased integrity investment.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers. We do not anticipate that future changes in revenues resulting from variances in commodity prices 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 gathering crude oil purchase volumes, NGL 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.

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, 2013	2012	2011	Favorable/(Unfavorable) 2013-2012 $	2013-2012 %	2012-2011 $	2012-2011 %
Revenues	$ 40,696	$ 36,440	$ 33,068	$ 4,256	12%	$ 3,372	10%
Purchases and related costs [2]	(39,315)	(35,139)	(31,984)	(4,176)	(12)%	(3,155)	(10)%
Field operating costs (excluding equity-indexed compensation expense)	(422)	(417)	(314)	(5)	(1)%	(103)	(33)%
Equity-indexed compensation expense - operations	(3)	(2)	(2)	(1)	(50)%	—	—%
Segment general and administrative expenses [3] (excluding equity-indexed compensation expense)	(102)	(101)	(86)	(1)	(1)%	(15)	(17)%
Equity-indexed compensation expense - general and administrative	(32)	(28)	(35)	(4)	(14)%	7	20%
Segment profit	$ 822	$ 753	$ 647	$ 69	9%	$ 106	16%
Maintenance capital	$ 15	$ 13	$ 12	$ (2)	(15)%	$ (1)	(8)%
Segment profit per barrel	$ 2.09	$ 2.05	$ 2.05	$ 0.04	2%	$ —	—%

Average Daily Volumes (in thousands of barrels per day)	For the Year Ended December 31, 2013	2012	2011	Favorable (Unfavorable) 2013-2012 Volume	%	2012-2011 Volume	%
Crude oil lease gathering purchases	859	818	742	41	5%	76	10%
NGL sales	215	182	103	33	18%	79	77%
Waterborne cargos	4	3	21	1	33%	(18)	(86)%
Supply and Logistics segment total	1,078	1,003	866	75	7%	137	16%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil and NGL inventory) of approximately $30 million, $12 million and $20 million for the years ended December 31, 2013, 2012, and 2011, respectively.

(3) Segment general and administrative expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments. The proportional allocations by segment require judgment by management and are based on the business activities that exist during each period.

The NYMEX West Texas Intermediate benchmark price of crude oil ranged from approximately $87 to $111 per barrel, $77 to $111 per barrel, and $75 to $115 per barrel during 2013, 2012, and 2011, 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 increases in volumes in the comparative 2013 and 2012 periods. The increase in 2012 over 2011 was further impacted by higher commodity prices.

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. Also, our NGL marketing operations are sensitive to weather-related demand, 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 NGL demand and thus our 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. Our Supply and Logistics segment revenues, net of purchases and related costs and excluding gains and losses from derivative activities (see the "Impact from Derivative Activities" section below), increased year-over-year for each of the comparative periods presented. The following summarizes the more significant items in the comparative periods:

- NGL Marketing Operations — Revenues from our NGL marketing operations increased during the year ended December 31, 2013 as compared to the year ended December 31, 2012, primarily due to more favorable market prices and higher demand related to (i) increases in export capacity in the U.S. that reduced overall product availability in the market, (ii) increased heating requirements during the extended winter season, (iii) heavy crop drying and (iv) petrochemical demand as well as more favorable supply contracts. Additionally, NGL margins during the 2012 period were negatively impacted by the sale of NGL product at points in time where spot prices were less than our weighted average inventory cost, primarily associated with inventory acquired in the BP NGL Acquisition on April 1, 2012. NGL sales volumes increased over the comparative year ended December 31, 2012 primarily due to increased demand as discussed above, as well as the impact from our BP NGL Acquisition.

- North American Crude Oil Production and Related Market Economics — The increasing production of oil and liquids-rich gas in North America over the last several years generally created supply and demand imbalances that increased the volatility of historical differentials for various grades of crude oil and also impacted the historical pricing relationship between NGL and crude oil. Lack of existing pipeline takeaway capacity and associated logistical challenges in certain of these producing regions created market conditions and opportunities that were favorable to our supply and logistics activities. During 2012 and the first quarter of 2013, these conditions provided opportunities for increased margins. However, infrastructure additions in many of these resource plays during the second and third quarters of 2013 began to relieve certain of the transportation constraints that had created opportunities for these favorable crude oil margins. Therefore, although we experienced higher crude oil lease gathering volumes in 2013 compared to 2012, we experienced fewer opportunities to capture favorable differentials from market dislocations.

We believe the fundamentals of our business remain strong; however, as the midstream infrastructure in these producing regions continues to be developed, we believe a normalization of margins will continue to occur as the logistics challenges are addressed. (See Items 1 and 2 "Business and Properties—Description of Segments and Associated Assets—Supply and Logistics Segment—Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model" included in Part I for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

Impact from derivative activities. The mark-to-market valuation of our derivative activities impacted our net revenues as shown in the table below (in millions):

	For the Twelve Months Ended December 31,			Variance	
	2013	2012	2011	2013-2012	2012-2011
Gains/(losses) from derivative activities[1]	$ (59)	$ (75)	$ 62	$ 16	$ (137)

(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. These amounts are reduced by the net impact of inventory valuation adjustments attributable to inventory hedged by the related derivative and gains recognized in later periods on physical sales of inventory that was previously written down. See Note 11 to our Consolidated Financial Statements for a comprehensive discussion regarding our derivatives and risk management activities.

Field Operating Costs. The increase in field operating costs (excluding equity-indexed compensation expenses) for the year ended December 31, 2012 over the year ended December 31, 2011 was primarily related to increased lease gathering volumes, particularly in West Texas, Oklahoma and the Rockies, which required the use of higher cost, third-party transporters to supplement our truck fleet.

Equity-Indexed Compensation Expense. On a consolidated basis, equity-indexed compensation expense increased during 2013 as compared to 2012 and decreased during 2012 as compared to 2011. See the discussion regarding such variances under "—Transportation Segment" above. Also, see Note 15 to our Consolidated Financial Statements for additional information regarding our equity-indexed compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was $378 million for the year ended December 31, 2013 compared to $483 million and $250 million for the years ended December 31, 2012 and 2011. Such amounts include losses on impairments of long-lived assets of approximately $20 million, $168 million and $5 million, for the 2013, 2012 and 2011 periods, respectively. The impairments recognized in 2013 and 2011 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 some instances, we utilized other assets to handle these activities. The impairments recognized in 2012 primarily related to our Pier 400 terminal project and the anticipated sale of certain refined products pipeline systems and related assets, which occurred in 2013. See Note 6 to our Consolidated Financial Statements for further discussion of asset impairments.

Excluding the impact of asset impairments, depreciation and amortization expense increased during the 2013 period over the comparable 2012 period primarily due to an increased amount of assets resulting from acquisition activities, as well as various internal growth projects completed in recent years.

Excluding the impact of asset impairments, the remaining increase for the 2012 as compared to the 2011 period was primarily the result of an increased amount of assets resulting from acquisition activities, including accelerated amortization of certain intangible assets associated with our BP NGL Acquisition, as well as the completion of various internal growth projects. Such increases were partially offset by a decrease in expense of $13 million resulting from extensions of depreciable lives of several of our crude oil and other storage facilities and pipeline systems, as well as a net gain of approximately $6 million recognized upon disposition of certain assets.

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Interest Expense

Interest expense increased by approximately $14 million and $36 million for the years ended December 31, 2013 and 2012, respectively, over the previous year. 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, 2013 and 2012 (in millions, except for percentages):

		Average LIBOR Rate	Weighted Average Interest Rate [(1)]
Interest expense for the year ended December 31, 2011	$ 259	0.2%	5.5%
Impact of retirement of senior notes [(2)] [(4)]	(8)		
Impact of issuance of senior notes [(3)] [(5)]	44		
Impact of capitalized interest	(11)		
Impact of credit facilities	(3)		
Impact of interest included in purchases and other costs [(8)]	8		
Other	6		
Interest expense for the year ended December 31, 2012	$ 295	0.2%	5.2%
Impact of retirement of senior notes [(4)] [(7)]	(15)		
Impact of issuance of senior notes [(5)] [(6)]	47		
Impact of ineffective portion of terminated forward-starting swaps	(4)		
Impact of credit facilities and commercial paper program	18		
Impact of interest included in purchases and other costs [(8)]	(18)		
Other	(14)		
Interest expense for the year ended December 31, 2013	$ 309	0.2%	4.4%

(1) Excludes commitment and other fees.

(2) In February 2011, PAA redeemed its outstanding $200 million, 7.75% senior notes due 2012.

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

(4) In September 2012, PAA's $500 million, 4.25% senior notes matured.

(5) In March 2012, PAA completed the issuance of $750 million of 3.65% senior notes due 2022 and $500 million of 5.15% senior notes due 2042, and in December 2012, PAA completed the issuance of $400 million of 2.85% senior notes due 2023 and $350 million of 4.30% senior notes due 2043.

(6) In August 2013, PAA completed the issuance of $700 million of 3.85% senior notes due 2023.

(7) In December 2013, PAA’s $250 million, 5.63% senior notes matured.

(8) Interest costs attributable to borrowings for hedged crude oil and NGL inventory 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 costs were approximately $30 million, $12 million and $20 million for the years ended December 31, 2013, 2012, and 2011, respectively.

Other Income/(Expense), Net

Other income/(expense), net in each of the years ended December 31, 2013 and 2012 was primarily impacted by foreign currency gains or losses related to revaluations of CAD-denominated interest receivables associated with intercompany notes and the impact of related foreign currency hedges.

In addition to the impact of such foreign currency gains, the 2011 period also included a loss of approximately $23 million that was recognized in conjunction with the early redemption of PAA’s $200 million, 7.75% senior notes in February 2011.

Income Tax Expense

Income tax expense increased for year ended December 31, 2013 compared to the year ended December 31, 2012 primarily as a result of stronger performance from our existing Canadian operations and our operations related to the BP NGL Acquisition, both of which increased the proportion of earnings subject to Canadian federal and provincial taxes.

Income tax expense increased for the year ended December 31, 2012 compared to the year ended December 31, 2011, even with a slight decrease in the combined Canadian federal and provincial rates for 2012, primarily as a result of the BP NGL Acquisition which increased the proportion of earnings subject to Canadian federal and provincial taxes. Canadian withholding taxes also increased on interest and dividends from our Canadian entities to other affiliates. These Canadian withholding taxes are due as payments occur.

Outlook

Primarily as a result of advances in drilling and completion techniques and their application to a number of large-scale shale and resource plays occurring contemporaneously with attractive crude oil and liquids prices, U.S. crude oil and liquids production has increased rapidly in multiple regions in the lower 48 states. This is particularly true for light crudes and condensates. As a result of similar resource development activities in Canada and ongoing oil sands development activities, Canadian crude oil production has also increased. A significant portion of these activities and production increases are concentrated 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 asset base as well as the services we provide our customers throughout the value chain.

Additionally, the crude oil market has periodically experienced high levels of volatility in location and quality differentials as a result of the confluence of regional infrastructure constraints in North America, rapid and unexpected changes in crude qualities, international supply issues, and regional downstream operating issues. During 2012 and 2013, these market conditions had a positive impact on our profitability as our business strategy and asset base positioned us to capitalize on opportunities created by the volatile environment. As a result of the factors enumerated above we believe current U.S. and Canadian energy industry fundamentals are favorable for our asset base and business model.

However, despite the prevailing outlook for steady growth in U.S. and Canadian crude oil production and the continuing opportunity to displace waterborne foreign crude imports to balance the North American market, we believe global oil and petroleum products supply and demand balances are such that the potential exists for a disruption that leads to lower than forecasted rates of growth in North American crude oil production. Potential disruption catalysts include a meaningful decrease in crude oil prices and/or capital availability coupled with an overall increase in cost of capital. Accordingly, there can be no assurance that North American production increases will continue unabated or that we will not be negatively impacted by potential volatility or challenging capital markets conditions. Additionally, construction of additional infrastructure by us and our competitors will likely continue to reduce existing infrastructure constraints, which could place downward pressure on unit margins in our various segments, 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 PAA’s Business.”

Liquidity and Capital Resources

General

On a consolidated basis, our primary sources of liquidity are (i) cash flow from operating activities as further discussed below in the section entitled "—Cash Flow from Operating Activities," (ii) borrowings under credit facilities or the PAA commercial paper program and (iii) funds received from PAA's sales of equity and debt securities. 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, NGL and other products and other expenses and interest payments on outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on long-term debt and (v) distributions to our Class A shareholders and noncontrolling interests. We generally expect to fund our short-term cash requirements through cash flow generated from operating activities and/or borrowings under credit facilities or the PAA commercial paper program. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing long-term debt, through a variety of sources (either separately or in combination), which may include the sources mentioned above as funding for short-term needs, and/or the issuance of additional PAA equity or debt securities. As of December 31, 2013, we had a working capital deficit of approximately $448 million and approximately $1.95 billion of liquidity available to meet our ongoing operating, investing and financing needs as noted below (in millions):

	As of December 31, 2013
Availability under PAA senior unsecured revolving credit facility, prior to giving effect to PAA commercial paper program [1]	$ 1,587
Availability under PAA senior secured hedged inventory facility, prior to giving effect to PAA commercial paper program [1]	1,372
Less: Amounts outstanding under the PAA commercial paper program	(1,109)
Subtotal	1,850
Availability under AAP senior secured revolving credit facility	60
Cash and cash equivalents	43
Total	$ 1,953

(1) Borrowings under the PAA commercial paper program reduce available capacity under the facility.

We believe that we have and will continue to have the ability to access the credit facilities and PAA commercial paper program, 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 and PAA commercial paper program is subject to ongoing compliance with covenants. As of December 31, 2013, AAP and PAA were in compliance with all such covenants.

Cash Flow from Operating Activities

The primary drivers of cash flow from operating activities are (i) the collection of amounts related to the sale of crude oil, NGL 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, NGL and other products and other expenses, principally field operating costs, general and administrative expenses and interest expense.

Cash flow from operating activities can be materially impacted by 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. In the month we pay for the stored crude oil, we borrow under the credit facilities or PAA commercial paper program (or use cash on hand) to pay for the crude oil, which negatively impacts 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 NGL 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 credit facilities or the PAA commercial paper program 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 credit facilities or the PAA commercial paper program to pay for the inventory or linefill. In addition, cash flow from operating activities 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.

Net cash provided by operating activities for the year ended December 31, 2013 was approximately $1.95 billion, primarily resulting from earnings from our operations. Additionally, during 2013, we decreased the amount of our inventory, primarily due to the sale of crude oil inventory that had been stored during the contango market, as well as the sale of NGL inventory due to end users' increased demand for product used for heating and crop drying during the latter half of 2013. The net proceeds received from liquidation of such inventory during the year were used to repay borrowings under credit facilities or the PAA commercial paper program and favorably impacted cash flow from operating activities. These decreases in inventory were partially offset by an increase in natural gas inventory whereby we retained more capacity for our own use. We primarily used borrowings under credit facilities to pay for the stored natural gas, which negatively impacted our cash flow from operating activities. Also, a significant portion of our 2013 natural gas sales occurred in December 2013, with cash collections on these sales occurring in January 2014.

Net cash provided by operating activities for the twelve months ended December 31, 2012 was approximately $1.23 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 2012, we increased the amount of our crude oil inventory, which was primarily financed through borrowings under credit facilities as well as through PAA's $250 million senior notes that are currently classified as "Short-term debt" on our Consolidated Balance Sheet. This resulted in a negative impact on our cash flow from operating activities for the period. During the year, we also increased the amount of our NGL inventory; however, these volumetric increases were offset by lower prices for such inventory stored at the end of the year compared to prior year amounts.

Net cash provided by operating activities for the twelve months ended December 31, 2011 was approximately $2.36 billion. 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 was 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 of 2011, as well as liquidating the inventory stored through our waterborne cargo purchase activity, which occurred throughout the third and fourth quarters of 2011.

Credit Agreements, PAA Commercial Paper Program and Indentures

PAA has three primary credit arrangements. These include a $1.6 billion senior unsecured revolving credit facility maturing in 2018 and a $1.4 billion senior secured hedged inventory facility maturing in 2016. Additionally, PAA has a $1.5 billion unsecured commercial paper program that is backstopped by its revolving credit facility and hedged inventory facility. The PAA credit agreements (which impact the ability to access the PAA commercial paper program) and the indentures governing PAA's senior notes contain cross-default provisions. A default under PAA's credit agreements would permit the lenders to accelerate the maturity of the outstanding debt. As long as PAA is in compliance with the provisions in its credit agreements, PAA's ability to make distributions of available cash is not restricted. PAA is in compliance with the covenants contained in its credit agreements and indentures as of December 31, 2013. In addition, AAP has a credit agreement which includes a $500 million term loan facility and a $75 million senior secured revolving credit facility. AAP is in compliance with the covenants contained in its credit agreement as of December 31, 2013. See Note 9 to our Consolidated Financial Statements for additional discussion regarding credit agreements, the PAA commercial paper program and long-term debt.

Equity and Debt Financing Activities

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

PAA Registration Statements. PAA periodically accesses the capital markets for both equity and debt financing. PAA has filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows PAA to issue up to an aggregate of $2.0 billion of debt or equity securities ("Traditional Shelf"). At December 31, 2013, PAA had approximately $1.5 billion of unsold securities available under the Traditional Shelf. PAA also has access to a universal shelf registration statement ("WKSI Shelf"), which provides it with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and capital needs.

PAA Equity Offerings. The following table summarizes the issuance of PAA's common units in connection with marketed equity offerings or PAA's Continuous Offering Program during the three years ended December 31, 2013 (net proceeds in millions):

Year	Type of Offering	PAA Common Units Issued	Net Proceeds [1]
2013	Continuous Offering Program	8,644,807	$ 468[2]
2013 Total		**8,644,807**	**$ 468**
2012	Continuous Offering Program	12,063,707	$ 513[2]
2012	Marketed Offerings	11,500,000	446[3]
2012 Total		**23,563,707**	**$ 959**
2011	Marketed Offerings	27,870,000	$ 870[3]
2011 Total		**27,870,000**	**$ 870**

(1) Amounts do not include PAA's general partner's proportionate capital contributions. Amounts are net of costs associated with the offerings.

(2) PAA pays commissions to its sales agents in connection with common unit issuances under its Continuous Offering Program. PAA paid approximately $5 million and $6 million of such commissions during 2013 and 2012, respectively. The net proceeds from these offerings were used for general partnership purposes.

(3) These offerings of PAA's common units were underwritten transactions that required PAA to pay a gross spread. The net proceeds from these offerings were used to reduce outstanding borrowings under PAA's credit facilities and for general partnership purposes.

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

Year	Description	Maturity	Face Value	Net Proceeds[1]
2013	3.85% Senior Notes issued at 99.792% of face value [2]	October 2023	$ 700	$ 699
2012	2.85% Senior Notes issued at 99.752% of face value [2]	January 2023	$ 400	$ 399
2012	4.30% Senior Notes issued at 99.925% of face value [2]	January 2043	$ 350	$ 350
2012	3.65% Senior Notes issued at 99.823% of face value [3]	June 2022	$ 750	$ 748
2012	5.15% Senior Notes issued at 99.755% of face value [3]	June 2042	$ 500	$ 499
2011	5.00% Senior Notes issued at 99.521% of face value [4]	February 2021	$ 600	$ 597

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

(2) PAA used the net proceeds from this offering to repay outstanding borrowings under its credit facilities or commercial paper program and for general partnership purposes.

(3) PAA used the net proceeds from this offering to repay outstanding borrowings under its credit facilities and for general partnership purposes. In addition, PAA used a portion of the proceeds to prefund the BP NGL Acquisition. See Note 3 to our Consolidated Financial Statements for a discussion of the BP NGL Acquisition.

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

In December 2013, PAA's $250 million, 5.63% senior notes matured and were repaid with proceeds from the PAA commercial paper program. In September 2012, PAA's $500 million, 4.25% senior notes matured and were repaid with proceeds from its credit facilities.

In February 2011, PAA's $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. PAA utilized cash on hand and available capacity under its credit facilities to redeem these notes.

Acquisitions and Capital Expenditures and Distributions Paid to Our Class A Shareholders and Noncontrolling Interests

In addition to operating needs discussed above, on a consolidated basis, we also use cash for acquisition activities, internal growth projects and distributions paid to our Class A shareholders 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.

2014 Capital Expansion Projects. We expect the majority of funding for our 2014 capital program will be provided by borrowings under PAA's revolving credit facility or commercial paper program and cash flow in excess of partnership distributions as well as through PAA's access to the capital markets for equity and debt as deemed necessary. Our 2014 capital expansion program includes the following projects with the estimated cost for the entire year (in millions):

Projects	2014
Permian Basin Area Projects	$430
Cactus Pipeline	310
Rail Terminal Projects [1]	185
Ft. Sask Facility Projects / NGL Pipeline	180
Eagle Ford JV Project	60
Western Oklahoma Extension	50
Mississippian Lime Pipeline	45
White Cliffs Expansion	40
Line 63 Reactivation	35
Gardendale Fractionator and Stabilizer	35
Natural Gas Storage (Multiple Projects)	25
Other Projects	305
	$1,700
Potential Adjustments for Timing/Scope Refinement [2]	-$100 + $100
Total Projected Expansion Capital Expenditures	$1,600 - $1,800

(1) Includes projects located in or near Bakersfield, CA, Carr, Co, Van Hook, ND and Western Canada.

(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 permits, regulatory approvals and weather.

Distributions to our Class A shareholders. We distribute 100% of our available cash within 55 days after the end of each quarter to Class A shareholders of record. 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, 2014, we paid a quarterly distribution of $0.12505 per Class A share, which was prorated for the partial quarter following the closing of our IPO on October 21, 2013. This distribution corresponds to a distribution of $0.15979 per Class A share ($0.63914 per Class A share on an annualized basis) before proration, assuming our ownership of AAP for the full fourth quarter of 2013. See Note 10 to our Consolidated Financial Statements for details of distributions paid. Also, see Item 5. "Market for Registrant's Shares, Related Shareholder Matters and Issuer Purchases of Equity Securities-Cash Distribution Policy" for additional discussion on distributions.

Distributions Prior to our IPO. Prior to the completion of our IPO in October 2013, we distributed $6 million to the members of GP LLC during 2013. Of this amount, approximately $3 million relates to distributions received from AAP related to the net proceeds from the increase in AAP's term loan. See Note 9 to the Consolidated Financial Statements for further discussion. During the years ended December 31, 2012 and 2011, $3 million and $2 million, respectively, were distributed to the members of GP LLC.

Distributions to noncontrolling interests. Distributions to noncontrolling interests represent amounts paid on interests in consolidated entities that are not owned by us. During the years ended December 31, 2013, 2012 and 2011, we paid distributions of approximately $1.5 billion, $1.0 billion and $822 million, respectively, to noncontrolling interests. Of the amount distributed during the year ended December 31, 2013, approximately $296 million relates to distributions paid for the noncontrolling interests' proportionate share of the net proceeds from the increase in AAP's term loan. See Note 10 to the Consolidated Financial Statements for further discussion.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under 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.

Distribution of Net Proceeds of our IPO. In October 2013, we completed our IPO of 132,382,094 Class A shares representing limited partner interests at a price of $22.00 per Class A share, generating net proceeds, after deducting underwriting discounts and commissions and direct offering expenses, of approximately $2.8 billion. We distributed these net proceeds to certain owners of AAP who, prior to our IPO, sold a portion of their interests in AAP to us in exchange for the right to receive an amount equal to the net proceeds of the IPO.

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Contingencies

For a discussion of contingencies that may impact us, see Note 16 to our Consolidated Financial Statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years with a limited number of contracts extending up to approximately ten 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, 2013 (in millions):

	2014	2015	2016	2017	2018	2019 and Thereafter	Total
Long-term debt, including related interest payments [1]	$ 361	$ 904	$ 510	$ 705	$1,390	$ 7,350	$ 11,220
Leases [2]	152	132	124	103	78	386	975
Other obligations [3]	216	80	46	32	21	140	535
Subtotal	729	1,116	680	840	1,489	7,876	12,730
Crude oil, natural gas, NGL and other purchases [4]	9,952	4,560	4,341	3,634	2,389	7,503	32,379
Total	$10,681	$5,676	$5,021	$4,474	$3,878	$ 15,379	$ 45,109

(1) Includes debt service payments, interest payments due on PAA’s senior notes, interest payments on long-term borrowings outstanding under the AAP credit agreement and the commitment fee on assumed available capacity under the PAA revolving credit facilities. Although there may be short-term borrowings on the PAA revolving credit facilities, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no short-term borrowings were outstanding on the facilities) in the amounts above.

(2) Leases are primarily for (i) surface rentals, (ii) office rent, (iii) pipeline assets and (iv) trucks, trailers and railcars.

(3) Includes (i) other long-term liabilities, (ii) storage and transportation agreements and (iii) commitments related to capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $1 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during December 2013. 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 supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil, NGL and natural gas. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the product is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. Additionally, we issue letters of credit to support insurance programs and construction activities. At December 31, 2013 and 2012, we had outstanding letters of credit of approximately $41 million and $24 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, 2013 (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%	$ 315	$ —	$ 230
Eagle Ford Pipeline LLC	Crude Oil Pipeline	50%	$ 425	$ 9	$ —
White Cliffs Pipeline, LLC	Crude Oil Pipeline	36%	$ 449	$ 85	$ —
Frontier Pipeline Company	Crude Oil Pipeline	22%	$ 25	$ 3	$ —
Butte Pipe Line Company	Crude Oil Pipeline	22%	$ 26	$ 6	$ —

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

We are exposed to various market risks, including (i) commodity price risk, (ii) interest rate risk and (iii) currency exchange rate risk. 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 our exchange-cleared 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 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 commodity price risk associated with the following commodities:

- *Crude oil and refined products*

  We utilize crude oil and refined products derivatives to hedge commodity price risk inherent in our Supply and Logistics and Transportation segments. Our objectives for these derivatives include hedging anticipated purchases and sales, stored inventory, and storage capacity utilization. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

- *Natural gas*

  We utilize natural gas derivatives to hedge commodity price risk inherent in our Supply and Logistics and Facilities segments. Our objectives for these derivatives include hedging anticipated purchases and sales and managing our anticipated base gas requirements. We manage these exposures with various instruments including exchange-traded futures, swaps and options.

- *NGL*

  We utilize NGL derivatives, primarily butane and propane derivatives, to hedge commodity price risk inherent in our Supply and Logistics segment. Our objectives for these derivatives include hedging anticipated purchases and sales. We manage these exposures with various instruments including exchange-traded and over-the-counter futures, forwards, swaps and options.

See Note 11 to our Consolidated Financial Statements for further discussion regarding our hedging strategies and objectives.

Our policy is to (i) purchase only product for which we have a market, (ii) hedge our purchase and sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or other derivative instruments for the purpose of speculating on outright commodity price changes, as these activities could expose us to significant losses.

The fair value of our commodity derivatives and the change in fair value as of December 31, 2013 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 and related products	$ 24	$ 8	$ (4)
Natural gas	(20)	$ (9)	$ 9
NGL and other	(50)	$ (23)	$ 23
Total fair value	$ (46)		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. 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 commodity 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

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us 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 are not subject to interest rate risk. The majority of our variable rate debt at December 31, 2013, approximately $1.6 billion, is subject to interest rate re-sets, which range from one week to three months. The average interest rate of approximately 1.5% is based upon rates in effect during the year ended December 31, 2013. The fair value of our interest rate derivatives is an asset of approximately $26 million as of December 31, 2013. A 10% increase in the forward LIBOR curve as of December 31, 2013 would result in an increase of approximately $19 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of December 31, 2013 would result in a decrease of approximately $19 million to the fair value of our interest rate derivatives. See Note 11 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 exchange rate 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 our foreign currency derivatives is a liability of approximately $4 million as of December 31, 2013. A 10% increase in the exchange rate (USD-to-CAD) would result in a decrease of approximately $27 million to the fair value of our foreign currency derivatives. A 10% decrease in the exchange rate (USD-to-CAD) would result in an increase of approximately $28 million to the fair value of our foreign currency derivatives. See Note 11 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 information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the "Exchange Act") is (i) recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (ii) 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

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

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 2013 that has not previously been reported.