PLAINS GP HOLDINGS LP
Form 10-Q
November 22, 2013
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# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the quarterly period ended September 30, 2013**

**OR**

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**Commission file number: 1-36132**

# PLAINS GP HOLDINGS, L.P.

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware**<br>(State or other jurisdiction of<br>incorporation or organization) | **90-1005472**<br>(I.R.S. Employer<br>Identification No.) |
| **333 Clay Street, Suite 1600, Houston, Texas**<br>(Address of principal executive offices) | **77002**<br>(Zip Code) |

**(713) 646-4100**

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. o Yes x No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes o No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

| | |
|---|---|
| Large accelerated filer o | Accelerated filer o |
| Non-accelerated filer x<br>(Do not check if a smaller reporting company) | Smaller reporting company o |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). o Yes x No

As of November 15, 2013, there were 132,382,094 Class A Shares outstanding.

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**PLAINS GP HOLDINGS, L.P.**

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**Explanatory Note**

The historical financial information contained in this report relates to periods that ended prior to the completion of the initial public offering (the Offering or IPO ) of 132,382,094 Class A Shares (including 4,382,094 Class A Shares issued in connection with the partial exercise of the underwriter s overallotment option) of Plains GP Holdings, L.P. at a price of $22.00 per share. These Class A shares began trading on the New York Stock Exchange ( NYSE ) under the symbol PAGP on October 16, 2013, and the Offering closed on October 21, 2013. Consequently, the unaudited consolidated financial statements and related discussion of financial condition and results of operations contained in this report pertain to Plains All American GP LLC (the Company or GP LLC ), the predecessor entity to PAGP. See Note 1 and Note 15 for further discussion regarding the organization, basis of presentation, completion of PAGP s IPO and other related items.

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## PART I. FINANCIAL INFORMATION

## Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

### PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)

### CONDENSED CONSOLIDATED BALANCE SHEETS

**(in millions, except units)**

| | September 30, 2013 (unaudited) | December 31, 2012 |
|---|---|---|
| **ASSETS** | | |
| | | |
| **CURRENT ASSETS** | | |
| Cash and cash equivalents | $ 34 | $ 25 |
| Trade accounts receivable and other receivables, net | 3,562 | 3,564 |
| Inventory | 1,198 | 1,209 |
| Other current assets | 354 | 351 |
| Total current assets | 5,148 | 5,149 |
| | | |
| **PROPERTY AND EQUIPMENT** | 12,286 | 11,183 |
| Accumulated depreciation | (1,659) | (1,519) |
| | 10,627 | 9,664 |
| | | |
| **OTHER ASSETS** | | |
| Goodwill | 2,519 | 2,535 |
| Linefill and base gas | 770 | 707 |
| Long-term inventory | 218 | 274 |
| Investments in unconsolidated entities | 474 | 343 |
| Other, net | 536 | 587 |
| Total assets | $ 20,292 | $ 19,259 |
| | | |
| **LIABILITIES AND MEMBERS EQUITY** | | |
| | | |
| **CURRENT LIABILITIES** | | |
| Accounts payable and accrued liabilities | $ 4,051 | $ 3,824 |
| Short-term debt | 620 | 1,086 |
| Other current liabilities | 343 | 275 |
| Total current liabilities | 5,014 | 5,185 |
| | | |
| **LONG-TERM LIABILITIES** | | |
| Senior notes, net of unamortized discount of $15 and $15, respectively | 6,710 | 6,010 |
| Long-term debt under credit facilities and other | 808 | 510 |
| Other long-term liabilities and deferred credits | 554 | 586 |
| Total long-term liabilities | 8,072 | 7,106 |
| | | |
| **COMMITMENTS AND CONTINGENCIES (NOTE 11)** | | |

| | | | | |
|---|---|---|---|---|
| **MEMBERS EQUITY** | | | | |
| Members equity, excluding noncontrolling interests | | (3) | | |
| Noncontrolling interests | | 7,209 | | 6,968 |
| Total members equity | | 7,206 | | 6,968 |
| Total liabilities and members equity | $ | 20,292 | $ | 19,259 |

The accompanying notes are an integral part of these condensed consolidated financial statements.

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**PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)**

**CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS**

**(in millions, except per unit data)**

| | Three Months Ended September 30, 2013 | Three Months Ended September 30, 2012 | Nine Months Ended September 30, 2013 | Nine Months Ended September 30, 2012 |
|---|---|---|---|---|
| | (unaudited) | | (unaudited) | |
| **REVENUES** | | | | |
| Supply and Logistics segment revenues | $ 10,386 | $ 9,048 | $ 30,542 | $ 27,367 |
| Transportation segment revenues | 179 | 150 | 517 | 458 |
| Facilities segment revenues | 138 | 156 | 558 | 533 |
| Total revenues | 10,703 | 9,354 | 31,617 | 28,358 |
| **COSTS AND EXPENSES** | | | | |
| Purchases and related costs | 9,909 | 8,524 | 28,733 | 25,855 |
| Field operating costs | 326 | 292 | 1,010 | 860 |
| General and administrative expenses | 79 | 81 | 276 | 264 |
| Depreciation and amortization | 93 | 211 | 266 | 357 |
| Total costs and expenses | 10,407 | 9,108 | 30,285 | 27,336 |
| **OPERATING INCOME** | 296 | 246 | 1,332 | 1,022 |
| **OTHER INCOME/(EXPENSE)** | | | | |
| Equity earnings in unconsolidated entities | 19 | 9 | 42 | 25 |
| Interest expense (net of capitalized interest of $11, $9, $30 and $27, respectively) | (73) | (76) | (227) | (219) |
| Other income/(expense), net | 3 | 4 | 2 | 6 |
| **INCOME BEFORE TAX** | 245 | 183 | 1,149 | 834 |
| Current income tax expense | (17) | (10) | (69) | (33) |
| Deferred income tax (benefit)/expense | 8 | (3) | (10) | (11) |
| **NET INCOME** | 236 | 170 | 1,070 | 790 |
| Net income attributable to noncontrolling interests | (235) | (169) | (1,067) | (788) |
| **NET INCOME ATTRIBUTABLE TO GP LLC** | $ 1 | $ 1 | $ 3 | $ 2 |

The accompanying notes are an integral part of these condensed consolidated financial statements.

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**PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)**

**CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

**(in millions)**

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | **2013** | **2012** | **2013** | **2012** |
| | **(unaudited)** | | **(unaudited)** | |
| Net income | $ 236 | $ 170 | $ 1,070 | $ 790 |
| Other comprehensive income/(loss) | 39 | 84 | (98) | 37 |
| Comprehensive income | 275 | 254 | 972 | 827 |
| Comprehensive income attributable to noncontrolling interests | (274) | (253) | (969) | (825) |
| Comprehensive income attributable to GP LLC | $ 1 | $ 1 | $ 3 | $ 2 |

**PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)**

**CONDENSED CONSOLIDATED STATEMENT OF**

**CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME**

**(in millions)**

| | **Derivative Instruments** | **Translation Adjustments** | **Total** |
|---|---|---|---|
| Balance at December 31, 2012 | $ (121) | $ 200 | $ 79 |
| Reclassification adjustments | (124) | | (124) |
| Deferred gain on cash flow hedges, net of tax | 141 | | 141 |
| Currency translation adjustments | | (115) | (115) |
| Total period activity | 17 | (115) | (98) |
| Balance at September 30, 2013 | $ (104) | $ 85 | $ (19) |

The accompanying notes are an integral part of these condensed consolidated financial statements.

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**PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)**

**CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(in millions)**

| | Nine Months Ended September 30, 2013 | Nine Months Ended September 30, 2012 |
|---|---|---|
| | (unaudited) | |
| **CASH FLOWS FROM OPERATING ACTIVITIES** | | |
| Net income | $ 1,070 | $ 790 |
| Reconciliation of net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 266 | 357 |
| Inventory valuation adjustments | 7 | 128 |
| Equity-indexed compensation expense | 96 | 82 |
| Gain on sales of linefill and base gas | (5) | (17) |
| Settlement of terminated interest rate and foreign currency hedging instruments | 8 | (23) |
| (Gain)/loss on foreign currency revaluation | (6) | 2 |
| Deferred income tax expense | 10 | 11 |
| Other | (7) | (3) |
| Changes in assets and liabilities, net of acquisitions | 150 | (453) |
| Net cash provided by operating activities | 1,589 | 874 |
| | | |
| **CASH FLOWS FROM INVESTING ACTIVITIES** | | |
| Cash paid in connection with acquisitions, net of cash acquired | (28) | (1,537) |
| Additions to property, equipment and other | (1,217) | (852) |
| Cash received for sales of linefill and base gas | 25 | 55 |
| Cash paid for purchases of linefill and base gas | (61) | (94) |
| Investment in unconsolidated entities | (124) | (24) |
| Proceeds from sales of assets | 62 | 21 |
| Cash received upon formation of equity-method investment | | 55 |
| Other investing activities | 3 | |
| Net cash used in investing activities | (1,340) | (2,376) |
| | | |
| **CASH FLOWS FROM FINANCING ACTIVITIES** | | |
| Net borrowings/(repayments) under PAA senior secured hedged inventory facility (Note 7) | (659) | 619 |
| Net borrowings/(repayments) under PAA senior unsecured revolving credit facility (Note 7) | (92) | 26 |
| Net borrowings/(repayments) under PNG credit agreement (Note 7) | (32) | 54 |
| Net borrowings/(repayments) under AAP revolving credit facility (Note 7) | 1 | (4) |
| Proceeds from AAP term loan (Note 7) | 300 | |
| Net borrowings under PAA commercial paper program (Note 7) | 319 | |
| Proceeds from the issuance of PAA senior notes | 699 | 1,247 |
| Repayments of PAA senior notes | | (500) |
| Net proceeds from the issuance of PAA common units | 401 | 817 |
| Net proceeds from the issuance of PNG common units | 40 | |
| Distributions paid to noncontrolling interests | (1,182) | (737) |
| Distributions paid to members | (6) | (2) |
| Other financing activities | (26) | (12) |
| Net cash provided by/(used in) financing activities | (237) | 1,508 |
| | | |
| Effect of translation adjustment on cash | (3) | 1 |

| | | | | |
|---|---|---|---|---|
| Net increase in cash and cash equivalents | | 9 | | 7 |
| Cash and cash equivalents, beginning of period | | 25 | | 27 |
| Cash and cash equivalents, end of period | $ | 34 | $ | 34 |
| | | | | |
| Cash paid for: | | | | |
| Interest, net of amounts capitalized | $ | 234 | $ | 213 |
| Income taxes, net of amounts refunded | $ | 19 | $ | 59 |

The accompanying notes are an integral part of these condensed consolidated financial statements.

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**PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)**

**CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN MEMBERS EQUITY**

**(in millions)**

| | Members Equity (Excluding Noncontrolling Interests) | Noncontrolling Interests | Members Equity |
|---|---|---|---|
| | | (unaudited) | |
| Balance at December 31, 2012 | $ | $ 6,968 | $ 6,968 |
| Net income | 3 | 1,067 | 1,070 |
| Distributions | (6) | (1,182) | (1,188) |
| Issuance of PAA common units | | 400 | 400 |
| Issuance of PAA common units under LTIP | | 4 | 4 |
| Units tendered by employees to satisfy tax withholding obligations | | (15) | (15) |
| Equity-indexed compensation expense | | 31 | 31 |
| Distribution equivalent right payments | | (4) | (4) |
| Issuance of PNG common units | | 40 | 40 |
| Other | | (2) | (2) |
| Other comprehensive loss | | (98) | (98) |
| Balance at September 30, 2013 | $ (3) | $ 7,209 | $ 7,206 |

The accompanying notes are an integral part of these condensed consolidated financial statements.

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**PLAINS ALL AMERICAN GP LLC AND SUBSIDIARIES (PREDECESSOR OF PLAINS GP HOLDINGS, L.P.)**

**NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS**

**(unaudited)**

**Note 1 Organization and Basis of Presentation**

***Organization***

Plains GP Holdings, L.P. ( PAGP ) is a Delaware limited partnership formed on July 17, 2013 to own interests in the general partner entities of Plains All American Pipeline, L.P ( PAA ), a publicly traded Delaware limited partnership.

On October 21, 2013, PAGP completed its initial public offering ( IPO ). Immediately prior to the IPO, certain owners of Plains AAP, L.P. ( AAP ) sold a portion of their interests in AAP to PAGP, resulting in PAGP s ownership of an approximate 21.8% limited partnership interest in AAP. AAP is a Delaware limited partnership which 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 ( GP ), a Delaware limited liability company, which directly holds the 2% general partner interest in PAA. Also, through a series of transactions with PAGP s general partner and certain owners of Plains All American GP LLC ( GP LLC ) prior to the IPO, PAGP became the owner of a 100% managing member interest in GP LLC, a Delaware limited liability company formed on May 2, 2001, and GP LLC s general partner interest in AAP became a non-economic interest. Prior to these transactions and as of September 30, 2013, GP LLC held a 1% general partner interest in AAP. See Note 15 for further discussion regarding the completion of PAGP s IPO and other related items.

GP LLC manages the business and affairs of PAA and AAP. Except for certain matters relating to PAA that require the approval of the limited partners of PAA, and certain matters relating to AAP that require the approval of the limited partners of AAP or of PAGP as the sole member of GP LLC, either pursuant to the governing documents of PAA, AAP or GP LLC, or as may be required by non-waivable provisions of applicable law, GP LLC has full and complete authority, power and discretion to manage and control the business, affairs and property of PAA and AAP, to make all decisions regarding those matters and to perform any and all other acts or activities customary or incident to the management of PAA and AAP s business, including the execution of contracts and management of litigation. GP LLC employs all domestic officers and personnel involved in the operation and management of PAA and AAP. PAA s Canadian officers and personnel are employed by Plains Midstream Canada ULC.

PAA engages in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of natural gas liquids ( NGL ). The term NGL includes ethane and natural gasoline products as well as propane and butane, products which are also commonly referred to as liquefied petroleum gas ( LPG ). When used in this document, NGL refers to all NGL products including LPG. Through PAA s general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), it also owns and operates natural gas storage facilities.

Unless the context indicates otherwise, the terms Plains, we, us, our, ours and similar terms refer to PAGP, GP LLC, AAP, GP and PAA and consolidated subsidiaries. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 12 for further discussion of our operating segments.

***Basis of Consolidation and Presentation***

The accompanying unaudited condensed consolidated financial statements of GP LLC represent the predecessor financial statements of PAGP, which are based on the historical ownership percentages of GP LLC and AAP. Prior to the transactions immediately preceding the IPO, PAGP had no assets and PAGP had not conducted any activity through September 30, 2013 since its formation on July 17, 2013. These financial statements have been prepared from the separate financial records maintained by GP LLC and may not necessarily be indicative of the actual results of operations that might have occurred if PAGP had operated separately during those periods. In addition, the effects of the IPO and related equity transfers occurring in October 2013 are not reflected herein.

The accompanying unaudited condensed consolidated financial statements include GP LLC, all of its wholly owned subsidiaries and those entities that it controls. Under generally accepted accounting principles in the United States ( U.S. GAAP ), GP LLC consolidates AAP and PAA and its subsidiaries. Amounts associated with the limited partner units not owned by GP LLC are reflected in our results of operations as net income attributable to noncontrolling interests and in our balance sheet equity section as noncontrolling interests.

The accompanying unaudited condensed consolidated interim financial statements should be read in conjunction with PAGP s final prospectus dated October 15, 2013 (the Final Prospectus ) included in its Registration Statement on Form S-1, as amended (SEC File No. 333-190227). These financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission (the SEC ). All adjustments (consisting only of normal recurring adjustments) that in the opinion of management were necessary for a fair statement of the results for interim periods have been reflected. The condensed balance sheet data as of December 31, 2012 was derived from audited financial statements, but does not include all disclosures required by accounting principles generally accepted in the United States of America ( U.S. GAAP ). The results of operations for the three and nine months ended September 30, 2013 should not be taken as indicative results to be expected for the full year.

Subsequent events have been evaluated through the financial statements issuance date and have been included in the following footnotes where applicable.

**Potential Acquisition of Publicly-held Common Units of PNG**

On October 22, 2013, PAA announced its entry into a definitive agreement and plan of merger (the Merger Agreement ) with PNG that provides for a merger whereby PNG will become a wholly-owned subsidiary through a unit-for-unit exchange (the Merger ). Under the terms of the Merger Agreement, PAA will issue 0.445 PAA common units for each outstanding PNG common unit held by unitholders other than PAA, plus cash in lieu of any fractional PAA common units otherwise issuable in the Merger. There are approximately 33.0 million PNG common units owned by unitholders other than PAA and consummation of the transaction is expected to result in the issuance of approximately 14.7 million PAA common units. Prior to PAGP s IPO, but subject to consummation of the Merger on terms generally consistent with PAA s then existing proposal, the owners of AAP agreed to reduce their incentive distribution rights under PAA s Partnership Agreement by $12 million in each of 2014 and 2015, $10 million in 2016 and $5 million per year thereafter.

The closing of the Merger is subject to the satisfaction of certain conditions, including the approval of the Merger and the Merger Agreement at a special meeting of the unitholders of PNG by the affirmative vote of holders of a majority of the outstanding PNG common units (including PNG common units held by PAA) voting as a separate class and the affirmative vote of holders of a majority of PNG s outstanding subordinated units voting as a separate class. PAA owns 100% of the membership interests in the general partner of PNG, 100% of the outstanding subordinated units of PNG and approximately 46% of the 61.2 million outstanding common units of PNG. Pursuant to the Merger Agreement, PAA agreed to vote its common units and subordinated units in favor of the Merger. PAA anticipates that the Merger will close in the latter half of the fourth quarter of 2013 or the first quarter of 2014. The previously announced quarterly distribution of $0.3575 per PNG common unit payable to holders of record of such units on November 1, 2013 was paid on November 14, 2013 as scheduled.

***Definitions***

Additional defined terms are used in this Form 10-Q and shall have the meanings indicated below:

| | | |
|---|---|---|
| AOCI | = | Accumulated other comprehensive income |
| Bcf | = | Billion cubic feet |
| Btu | = | British thermal unit |

| | | |
|---|---|---|
| CAD | = | Canadian dollar |
| CME | = | Chicago Mercantile Exchange |
| DERs | = | Distribution equivalent rights |
| EBITDA | = | Earnings before interest, taxes, depreciation and amortization |
| FASB | = | Financial Accounting Standards Board |
| FERC | = | Federal Energy Regulatory Commission |
| ICE | = | IntercontinentalExchange |
| LIBOR | = | London Interbank Offered Rate |
| LLS | = | Light Louisiana Sweet |
| LTIP | = | Long-term incentive plan |
| Mcf | = | Thousand cubic feet |
| MLP | = | Master limited partnership |
| NGL | = | Natural gas liquids including ethane, natural gasoline products, propane and butane |
| NPNS | = | Normal purchases and normal sales |
| NYMEX | = | New York Mercantile Exchange |
| NYSE | = | New York Stock Exchange |
| PLA | = | Pipeline loss allowance |
| PNG | = | PAA Natural Gas Storage, L.P. |
| USD | = | United States dollar |
| WTI | = | West Texas Intermediate |
| WTS | = | West Texas Sour |

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**Note 2 Recent Accounting Pronouncements**

Other than as discussed below and in our 2012 Consolidated Financial Statements included in the Final Prospectus, no new accounting pronouncements have become effective or have been issued during the nine months ended September 30, 2013 that are of significance or potential significance to us.

In March 2013, the FASB issued guidance regarding the release of cumulative translation adjustments into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity. This guidance becomes effective beginning after December 15, 2013. We will adopt this guidance on January 1, 2014. Our adoption is not expected to have a material impact on our financial position, results of operations or cash flows.

In February 2013, the FASB issued guidance requiring an entity to present either in a single note or parenthetically on the face of the financial statements (i) the amount of significant items reclassified from each component of AOCI and (ii) the income statement line items affected by the reclassification. This guidance became effective for interim and annual periods beginning after December 15, 2012. We adopted this guidance during the first quarter of 2013. During the nine months ended September 30, 2013 and 2012, all reclassifications out of AOCI were related to derivative instruments. Other than requiring additional disclosure, which is included in Note 10, our adoption did not have an impact on our financial position, results of operations or cash flows.

In July 2012, the FASB issued guidance intended to simplify the impairment test for indefinite-lived intangible assets other than goodwill by giving entities the option to first assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired. The results of the qualitative assessment would be used as a basis in determining whether it is necessary to perform the two-step quantitative impairment testing. An entity can choose to perform the qualitative assessment on none, some or all of its indefinite-lived intangible assets, or may bypass the qualitative assessment and proceed directly to the quantitative impairment test. This guidance is effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption permitted in certain circumstances. We adopted this guidance on January 1, 2013. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In December 2011, the FASB issued guidance requiring disclosures of both gross and net information about recognized financial instruments and derivative instruments that are either (i) offset in accordance with the specified sections of GAAP or (ii) subject to an enforceable master netting arrangement or similar agreement. In January 2013, the FASB amended and clarified the scope of these disclosures to include only (i) derivative instruments, (ii) repurchase agreements and reverse repurchase agreements and (iii) securities lending transactions. This guidance is effective for annual reporting periods beginning on or after January 1, 2013, and interim periods within those annual periods. We adopted this guidance on January 1, 2013. Other than requiring additional disclosure, which is included in Note 10, our adoption did not have an impact on our financial position, results of operations or cash flows.

**Note 3 Accounts Receivable**

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of crude oil, NGL, natural gas and refined products terminalling and storage services. These purchasers include, but are not limited to refiners, producers, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

To mitigate credit risk related to our accounts receivable, we have in place a rigorous credit review process. We closely monitor market conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, parental guarantees or advance cash payments. At September 30, 2013 and December 31, 2012, we had received approximately $122 million and $173 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, at September 30, 2013 and December 31, 2012, we had received approximately $452 million and $343 million, respectively, of standby letters of credit to support obligations due from third parties, a portion of which applies to future business. In addition, in an effort to mitigate credit risk, a significant portion of our transactions with counterparties are settled on a net-cash basis. Further, we enter into netting agreements (contractual agreements that allow us to offset receivables and payables with those counterparties against each other on our balance sheet) for a majority of such arrangements.

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We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. We do not apply actual balances against the reserve until we have exhausted substantially all collection efforts. At September 30, 2013 and December 31, 2012, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 30 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled approximately $4 million at both September 30, 2013 and December 31, 2012. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

**Note 4 Dispositions**

In February 2013, PAA signed a definitive agreement to sell certain refined products pipeline systems and related assets included in our Transportation segment. At December 31, 2012, these assets were classified as held for sale on our condensed consolidated balance sheet (in Other current assets ). On July 1, 2013, a portion of the transaction closed with the sale of certain of the refined products pipeline systems and related assets. The remaining assets were classified as held for sale on our condensed consolidated balance sheet as of September 30, 2013. PAA closed the balance of the transaction during November 2013.

**Note 5 Inventory, Linefill and Base Gas and Long-term Inventory**

Inventory, linefill and base gas and long-term inventory consisted of the following as of the dates indicated (barrels and natural gas volumes in thousands and carrying value in millions):

| | September 30, 2013 | | | | December 31, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Volumes | Unit of Measure | Carrying Value | Price/ Unit (1) | Volumes | Unit of Measure | Carrying Value | Price/ Unit (1) |
| **Inventory** | | | | | | | | |
| Crude oil | 5,624 | barrels | $ 535 | $ 95.13 | 9,492 | barrels | $ 737 | $ 77.64 |
| NGL | 13,767 | barrels | 539 | $ 39.15 | 9,472 | barrels | 388 | $ 40.96 |
| Natural gas | 29,443 | Mcf | 101 | $ 3.43 | 20,374 | Mcf | 60 | $ 2.94 |
| Other | N/A | | 23 | N/A | N/A | | 24 | N/A |
| Inventory subtotal | | | 1,198 | | | | 1,209 | |
| | | | | | | | | |
| **Linefill and base gas** | | | | | | | | |
| Crude oil | 10,520 | barrels | 645 | $ 61.31 | 9,919 | barrels | 583 | $ 58.78 |
| NGL | 1,345 | barrels | 64 | $ 47.58 | 1,400 | barrels | 70 | $ 50.00 |
| Natural gas | 17,615 | Mcf | 61 | $ 3.46 | 15,755 | Mcf | 54 | $ 3.43 |
| Linefill and base gas subtotal | | | 770 | | | | 707 | |
| | | | | | | | | |
| **Long-term inventory** | | | | | | | | |
| Crude oil | 2,134 | barrels | 167 | $ 78.26 | 1,962 | barrels | 149 | $ 75.94 |
| NGL | 1,161 | barrels | 51 | $ 43.93 | 3,238 | barrels | 125 | $ 38.60 |
| Long-term inventory subtotal | | | 218 | | | | 274 | |

| | | |
|---|---|---|
| **Total** | $ 2,186 | $ 2,190 |

**(1)** Price per unit of measure represents a weighted average associated with various grades, qualities and locations. Accordingly, these prices may not coincide with any published benchmarks for such products.

At the end of each reporting period we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. We recorded a non-cash charge of approximately $7 million during the three and nine months ended September 30, 2013, primarily related to the writedown of our crude oil inventory due to declines in prices during the period. During the three and nine months ended September 30, 2012, we recorded non-cash charges of approximately $7 million and $128 million, respectively, related to the writedown of our crude oil and NGL inventory due to declines in prices during the period. The recognition of these adjustments in 2013 and 2012, which are a component of Purchases and related costs in our accompanying condensed consolidated statements of operations, was substantially offset by the recognition of gains on derivative instruments being utilized to hedge the future sales of our crude oil and NGL inventory. Substantially all of such gains were recorded to Supply and Logistics segment revenues on our condensed consolidated statements of operations. See Note 10 for discussion of our derivative and risk management activities.

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**Note 6 Goodwill**

The table below reflects our goodwill by segment and changes during the period indicated (in millions):

| | Transportation | | Facilities | | Supply and Logistics | | Total | |
|---|---|---|---|---|---|---|---|---|
| Balance at December 31, 2012 | $ | 897 | $ | 1,171 | $ | 467 | $ | 2,535 |
| 2013 Goodwill Related Activity: | | | | | | | | |
| Acquisitions | | 6 | | | | | | 6 |
| Foreign currency translation adjustments | | (10) | | (5) | | (2) | | (17) |
| Purchase price accounting adjustments and other **(1)** | | (5) | | | | | | (5) |
| Balance at September 30, 2013 | $ | 888 | $ | 1,166 | $ | 465 | $ | 2,519 |

**(1)** Goodwill is recorded at the acquisition date based on a preliminary fair value determination. This preliminary goodwill balance may be adjusted when the fair value determination is finalized.

We completed our annual goodwill impairment test as of June 30 and determined that there was no impairment of goodwill.

**Note 7 Debt**

Debt consisted of the following as of the dates indicated (in millions):

| | September 30, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| **SHORT-TERM DEBT** | | | | |
| Credit Facilities (1): | | | | |
| PAA senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.6% at December 31, 2012 (2) | $ | | $ | 665 |
| PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.4% at December 31, 2012 (2) | | | | 92 |
| AAP senior secured revolving credit facility, bearing a weighted-average interest rate of 1.9% at September 30, 2013 | | 1 | | |
| PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.0% and 2.1% at September 30, 2013 and December 31, 2012, respectively (3) | | 46 | | 77 |
| PAA commercial paper notes, bearing a weighted-average interest rate of 0.25% at September 30, 2013 (2) | | 319 | | |
| PAA 5.63% senior notes due December 2013 (4) | | 250 | | 250 |
| Other | | 4 | | 2 |
| Total short-term debt | | 620 | | 1,086 |

| | | |
|---|---|---|
| **LONG-TERM DEBT** | | |
| PAA senior notes, net of unamortized discounts of $15 at both September 30, 2013 and December 31, 2012 (5) | 6,710 | 6,010 |
| | | |
| Credit Facilities and Other Long-Term Debt (1): | | |
| AAP term loan, bearing a weighted-average interest rate of 1.9% and 1.8% at September 30, 2013 and December 31, 2012, respectively | 500 | 200 |
| PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.0% and 2.1% at September 30, 2013 and December 31, 2012, respectively (3) | 103 | 105 |
| PNG GO Bond term loans, bearing a weighted-average interest rate of 1.5% at both September 30, 2013 and December 31, 2012 | 200 | 200 |
| Other | 5 | 5 |
| Total long-term debt | 7,518 | 6,520 |
| Total debt (2) (3) (6) | $ 8,138 | $ 7,606 |

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**(1)** In 2013, we renewed and extended our principal bank credit facilities. See Credit Facilities below for further discussion.

**(2)** We classify as short-term certain borrowings under the PAA commercial paper program, PAA senior unsecured revolving credit facility and PAA senior secured hedged inventory facility. These borrowings are primarily designated as working capital borrowings, must be repaid within one year and are primarily for hedged NGL and crude oil inventory and NYMEX and ICE margin deposits.

**(3)** We classify as short-term debt any borrowings under the PNG senior unsecured revolving credit facility that have been designated as working capital borrowings and must be repaid within one year. Such borrowings are primarily related to a portion of PNG s hedged natural gas inventory.

**(4)** PAA s $250 million 5.63% senior notes will mature in December 2013 and are thus classified as short-term at September 30, 2013 and December 31, 2012.

**(5)** In August 2013, PAA completed the issuance of $700 million, 3.85% senior notes due 2023 at a public offering price of 99.792%. Interest payments are due on April 15 and October 15 of each year, commencing on April 15, 2014.

**(6)** PAA s fixed-rate senior notes (including current maturities) had a face value of approximately $7.0 billion and $6.3 billion at September 30, 2013 and December 31, 2012, respectively. We estimated the aggregate fair value of these notes as of September 30, 2013 and December 31, 2012 to be approximately $7.5 billion and $7.3 billion, respectively. PAA s fixed-rate senior notes are traded among institutions, and these trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near quarter end. We estimate that the carrying value of outstanding borrowings under our credit agreements and commercial paper program approximates fair value as interest rates reflect current market rates. The fair value estimates for our senior notes and borrowings under our credit agreements and commercial paper program are based upon observable market data and are classified within level 2 of the fair value hierarchy.

***Commercial Paper Program***

In August 2013, PAA established a commercial paper program under which it may issue, from time to time, privately placed, unsecured commercial paper notes for up to a maximum aggregate amount outstanding at any time of $1.5 billion. Such notes are backstopped by the PAA senior unsecured revolving credit facility and the PAA senior secured hedged inventory facility; as such, any borrowings under the commercial paper program reduce the available capacity under these facilities.

***Credit Facilities***

In August 2013, the PAA senior secured hedged inventory facility and PAA senior unsecured revolving credit facility agreements were amended to, among other things, extend the maturity dates of the facilities by two years. The facilities now mature in August 2016 and August 2018, respectively. Also in August 2013, the maturity dates of the PNG senior unsecured revolving credit facility and GO Bond term loans were extended by one year to August 2017.

In September 2013, the AAP credit agreement was amended to increase the term loan facility from $200 million to $500 million, increase the aggregate commitments under the revolving credit facility from $25 million to $75 million and extend the maturity date by one year to September 2018.

***Borrowings and Repayments***

Total borrowings under our credit agreements and commercial paper program for the nine months ended September 30, 2013 and 2012 were approximately $13.2 billion and $8.5 billion, respectively. Total repayments under our credit agreements and commercial paper program were approximately $13.4 billion and $7.8 billion for the nine months ended September 30, 2013 and 2012, respectively. The variance in total gross borrowings and repayments is impacted by various business and financial factors including, but not limited to, the timing, average term and method of general partnership borrowing activities.

***Letters of Credit***

In connection with our supply and logistics activities and natural gas storage and commercial marketing 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.  Additionally, we issue letters of credit to support insurance programs and construction activities.  At September 30, 2013 and December 31, 2012, we had outstanding letters of credit of approximately $42 million and $24 million, respectively.

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**Note 8 Members Equity**

***Distributions to Members***

We distribute all of the cash received from AAP distributions on a quarterly basis, less reserves established by management for future requirements. Generally, distributions are paid to our Members in proportion to their percentage interest in us. During the nine months ended September 30, 2013 and 2012, we distributed approximately $6 million and $2 million, respectively, to our Members. Of the amount distributed during the nine months ended September 30, 2013, approximately $3 million relates to distributions received from AAP for our proportionate share of the net proceeds from the increase in AAP s term loan. See Note 7 for further discussion.

***Noncontrolling Interests in Subsidiaries***

As of September 30, 2013, noncontrolling interests in subsidiaries consisted of (i) a 98% limited partner interest in PAA, (ii) a 99% limited partner interest in AAP that consists of Class A and Class B units of AAP (a profits interest), (iii) an approximate 37% limited partner interest in PNG and (iv) a 25% interest in SLC Pipeline LLC.

**PAA Continuous Offering Program**

In May 2013, PAA entered into an additional equity distribution agreement with several financial institutions pursuant to which it may offer and sell, through its sales agents, common units representing limited partner interests having an aggregate offering price of up to $750 million. During the nine months ended September 30, 2013, PAA issued an aggregate of approximately 7.2 million common units under its continuous offering program, generating net proceeds of approximately $400 million, including the proportionate capital contribution from our Members and the noncontrolling interests in AAP, net of approximately $4 million of commissions to our sales agents.

**LTIP Vesting**

In connection with the settlement of vested LTIP awards (both liability-classified and equity-classified), PAA issued approximately 0.5 million common units during the first nine months of 2013, net of units tendered by employees for tax withholding obligations.

**PNG Continuous Offering Program**

On March 18, 2013, PNG entered into an equity distribution agreement with a financial institution pursuant to which PNG may offer and sell, through its sales agent, common units representing limited partner interests having an aggregate offering price of up to $75 million. During the first nine months of 2013, PNG issued an aggregate of approximately 1.9 million common units under this agreement, generating net proceeds of approximately $40 million.

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**Noncontrolling Interests Rollforward**

The following table reflects the changes in the noncontrolling interests in members equity (in millions):

| | Nine Months Ended September 30, 2013 | 2012 |
|---|---|---|
| Beginning balance | $ 6,968 | $ 5,794 |
| Net income attributable to noncontrolling interests | 1,067 | 788 |
| Distributions to noncontrolling interests | (1,182) | (737) |
| Issuance of PAA common units (1) | 400 | 812 |
| Issuance of PAA common units under LTIP (1) | 4 | 34 |
| Units tendered by employees to satisfy tax withholding obligations | (15) | |
| Equity-indexed compensation expense | 31 | 23 |
| Distribution equivalent right payments | (4) | (4) |
| Issuance of PNG common units | 40 | |
| Other | (2) | |
| Other comprehensive income/(loss): | | |
| Reclassification adjustments | (124) | (115) |
| Net deferred gain on cash flow hedges | 141 | 68 |
| Currency translation adjustments | (115) | 84 |
| Ending balance | $ 7,209 | $ 6,747 |

(1) Includes contributions received or to be received from noncontrolling interests of AAP of approximately $9 million and $17 million for the nine months ended September 30, 2013 and 2012, respectively. This amount reflects reimbursement to AAP for capital contributions paid to PAA to maintain AAP s indirect 2% general partner interest in PAA.

**Note 9 Equity-Indexed Compensation Plans**

We refer to the PAA and PNG LTIP Plans, Special PAA Awards and Class B Units of AAP collectively as the Equity-indexed compensation plans. For additional discussion of equity-indexed compensation plans and awards, please read Note 14 to our 2012 Consolidated Financial Statements included in the Final Prospectus. In connection with PAGP s IPO, its general partner adopted the Plains GP Holdings, L.P. Long Term Incentive Plan. See Note 15 for further discussion.

*Class B Units of AAP.* The following table contains a summary of Class B Units of AAP:

| | Reserved for Future Grants (1) | Outstanding (1) | Outstanding Units Earned (1) | Grant Date Fair Value of Outstanding Class B Units (2) (in millions) |
|---|---|---|---|---|
| Balance at December 31, 2012 | 17,875 | 182,125 | 130,250 | $ 44 |
| Granted | (4,500) | 4,500 | | 7 |

| | | | | |
|---|---|---|---|---|
| Earned | N/A | N/A | 50,125 | N/A |
| Balance at September 30, 2013 | 13,375 | 186,625 | 180,375 | $ 51 |

(1) In connection with PAGP s IPO and the recapitalization of AAP on October 21, 2013, the number of Class B Units of AAP was adjusted; as such, as of such date, the number of Class B Units of AAP reserved for future grants, outstanding and earned following this adjustment was 3,483,102 units, 48,642,833 units and 47,013,803 units, respectively. See Note 15 for further discussion of PAGP s IPO.

(2) Of the grant date fair value, approximately $4 million was recognized as expense during the nine months ended September 30, 2013.

*Special PAA Awards.* In February 2013, 143,000 Special PAA Awards were granted to certain members of PNG s management. These awards are denominated in PAA common units and will vest 50% on PAA s August 2018 distribution date and 50% on PAA s August 2019 distribution date provided that PNG s annualized distribution averages at least $1.48 and $1.43 per unit, respectively, for the twelve months prior to each vesting date. DERs associated with these awards vested in November 2013. Any unvested Special PAA Awards that remain outstanding on December 31, 2020 will be forfeited.

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*PAA and PNG LTIP Awards.* Equity compensation activity for LTIP awards denominated in PAA and PNG units is summarized in the following table (units in millions):

| | PAA Units (1) (2) (3) | | | PNG Units (4) | | |
|---|---|---|---|---|---|---|
| | Units | | Weighted Average Grant Date Fair Value per Unit | Units | | Weighted Average Grant Date Fair Value per Unit |
| Outstanding at December 31, 2012 | 6.0 | $ | 25.55 | 0.9 | $ | 17.49 |
| Granted | 4.1 | $ | 47.60 | 0.4 | $ | 17.51 |
| Vested | (1.8) | $ | 24.82 | | $ | 18.88 |
| Cancelled or forfeited | (0.3) | $ | 36.32 | | $ | 13.33 |
| Outstanding at September 30, 2013 | 8.0 | $ | 36.74 | 1.3 | $ | 17.55 |

(1) Amounts do not include Class B Units of AAP.

(2) Amounts include Special PAA Awards.

(3) Approximately 0.5 million PAA common units were issued, net of approximately 0.3 million units withheld for taxes, for PAA units that vested during the nine months ended September 30, 2013. The remaining 1.0 million PAA units that vested were settled in cash.

(4) Less than 0.1 million PNG units vested and less than 0.1 million units were forfeited during the nine months ended September 30, 2013.

In February 2013, 2.4 million equity-classified phantom unit awards and 1.5 million liability-classified phantom unit awards were granted under the PAA LTIPs. Substantially all of the equity-classified awards vest as follows: (i) one-third will vest upon the later of the August 2016 distribution date and the date PAA pays an annualized quarterly distribution of at least $2.35 per common unit, (ii) one-third will vest upon the later of the August 2017 distribution date and the date PAA pays an annualized quarterly distribution of at least $2.50 per common unit, and (iii) one-third will vest upon the later of the August 2018 distribution date and the date PAA pays an annualized quarterly distribution of at least $2.65 per unit. Any of these equity-classified awards and associated DERs that have not vested as of the August 2019 distribution date will be forfeited. Substantially all of the liability-classified awards are expected to vest on dates ranging from the August 2015 distribution date to the August 2018 distribution date and vest dependent on PAA paying annualized quarterly distributions ranging from $2.30 per common unit to $2.65 per common unit. Certain of these phantom unit awards include DERs that will vest in one-third increments upon achieving distributions of $2.35, $2.50 and $2.65 per common unit, without regard to the minimum service period.

In November 2013, PAA s common unitholders approved the Plains All American 2013 Long Term Incentive Plan, which (i) consolidated PAA s three long-term incentive plans into a single plan through a consolidated amendment and restatement of the existing plans and (ii) authorized an incremental 7,000,000 PAA common units that may be issued under the long-term incentive plan.

*Other Equity-Indexed Compensation Information.* The table below summarizes the expense recognized and the value of vesting (settled both in units and cash) related to equity-indexed compensation plans and includes both liability-classified and equity-classified awards (in millions):

| | Three Months Ended September 30, | | | | Nine Months Ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2013 | | 2012 | | 2013 | | 2012 | |
| Equity-indexed compensation expense | $ | 17 | $ | 22 | $ | 96 | $ | 82 |
| LTIP unit-settled vestings (1) | $ | 1 | $ | 2 | $ | 47 | $ | 60 |
| LTIP cash-settled vestings | $ | | $ | 1 | $ | 61 | $ | 66 |
| DER cash payments | $ | 2 | $ | 2 | $ | 5 | $ | 5 |

(1) For the nine months ended September 30, 2012, less than $1 million relates to unit-settled vestings that were settled with PNG common units.

**Note 10 Derivatives and Risk Management Activities**

We identify the risks that underlie our core business activities and use risk management strategies to mitigate those risks when we determine that there is value in doing so. Our policy is to use derivative instruments for risk management purposes and not for the purpose of speculating on hydrocarbon commodity (referred to herein as commodity ) price changes. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange rate risk. Our commodity risk management policies and procedures are designed to help ensure that our hedging activities address our risks by monitoring our derivative positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity. Our interest rate and currency exchange rate risk management policies and procedures are designed to monitor our derivative positions and ensure that those positions are consistent with our objectives and approved strategies. When we apply hedge accounting, our policy is to formally document all relationships between

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hedging instruments and hedged items, as well as our risk management objectives for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

***Commodity Price Risk Hedging***

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is to (i) only purchase inventory for which we have a market, (ii) structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be divided into the following general categories:

*Commodity Purchases and Sales* In the normal course of our operations, we purchase and sell commodities. We use derivatives to manage the associated risks and to optimize profits. As of September 30, 2013, net derivative positions related to these activities included:

- An average of 316,500 barrels per day net long position (total of 9.8 million barrels) associated with our crude oil purchases, which was unwound ratably during October 2013 to match monthly average pricing.

- A net short spread position averaging approximately 32,800 barrels per day (total of 13.0 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through December 2014. These derivatives are time spreads consisting of offsetting purchases and sales between two different months. Our use of these derivatives does not expose us to outright price risk.

- An average of 13,700 barrels per day (total of 1.7 million barrels) of crude oil grade spread positions through January 2014, which hedge anticipated purchases and sales of crude oil. These derivatives are grade spreads between WTI and various other grades of crude oil including WTS, LLS and Brent. Our use of these derivatives does not expose us to outright price risk.

- An average of 2,500 barrels per day (total of 1.4 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a percentage of WTI through March 2015.

- A net long position of approximately 1.3 Bcf through April 2016 related to anticipated base gas requirements.

- A short position of approximately 29.4 Bcf through January 2014 related to anticipated sales of natural gas inventory.

- A short position of approximately 10.7 million barrels through March 2015 related to the anticipated sales of our crude oil, NGL and refined products inventory.

*Storage Capacity Utilization* We own a significant amount of crude oil, NGL and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk in a backwardated market structure. As of September 30, 2013, we used derivatives to manage the risk of not utilizing approximately 2.2 million barrels per month of storage capacity through December 2013. These positions involve no outright price exposure, but instead enable us to profitably use the capacity to store hedged crude oil.

*Pipeline Loss Allowance Oil* As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of September 30, 2013, our PLA hedges included a net short position for an average of approximately 1,700 barrels per day (total of 1.4 million barrels) through December 2015 and a long call option position of approximately 0.6 million barrels through December 2015.

*Natural Gas Processing/NGL Fractionation* As part of our supply and logistics activities, we purchase natural gas for processing and NGL mix for fractionation, and we sell the resulting individual specification products (including ethane, propane, butane and condensate). In conjunction with these activities, we hedge the price risk associated with the purchase of the natural gas and the subsequent sale of the individual specification products. As of September 30, 2013, we had a long natural gas position of approximately 16.3 Bcf through March 2015, a short propane position of approximately 2.9 million barrels through March 2015, a

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short butane position of approximately 0.9 million barrels through March 2015 and a short WTI position of approximately 0.3 million barrels through March 2015. In addition, we had a long power position of 0.5 million megawatt hours which hedges a portion of our power supply requirements at our natural gas processing and fractionation plants through December 2015.

All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion. Physical commodity contracts that meet the definition of a derivative but are ineligible, or not designated, for the NPNS scope exception are recorded on the balance sheet at fair value, with changes in fair value recognized in earnings.

***Interest Rate Risk Hedging***

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of September 30, 2013, AOCI includes deferred losses of approximately $76 million that relate to open and terminated interest rate derivatives that were designated for hedge accounting. The terminated interest rate derivatives were cash-settled in connection with the issuance or refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

PAA entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2015. The following table summarizes the terms of these forward starting interest rate swaps as of September 30, 2013 (notional amounts in millions):

| **Hedged Transaction** | **Number and Types of Derivatives Employed** | **Notional Amount** | **Expected Termination Date** | **Average Fixed Rate** | **Accounting Treatment** |
|---|---|---|---|---|---|
| Anticipated debt offering | 10 forward starting swaps (30-year) | $ 250 | 6/15/2015 | 3.60% | Cash flow hedge |

Concurrent with PAA s August 2013 senior notes issuance, five thirty-year forward starting swaps were terminated. We received cash proceeds of approximately $11 million, of which a gain of approximately $8 million was deferred in AOCI and a gain of approximately $3 million was recognized in interest expense attributable to the ineffective portion, in connection with the termination of these swaps.

During June 2011 and August 2011, PNG entered into three interest rate swaps to fix the interest rate on a portion of PNG s outstanding debt. The following table summarizes the terms of these swaps (notional amount in millions):

| **Hedged Transaction** | **Number and Types of Derivatives Employed** | **Notional Amount** | **Termination Dates** | **Average Fixed Rate** | **Accounting Treatment** |
|---|---|---|---|---|---|
| Floating interest rate payments associated with PNG outstanding debt | 3 floating-to-fixed swaps | $ 100 | 6/6/2014<br>8/3/2014 | 0.95% | Cash flow hedge |

***Currency Exchange Rate Risk Hedging***

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 foreign currency derivatives to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts and forwards. As of September 30, 2013, AOCI includes net deferred gains of approximately $1 million that relate to foreign currency derivatives that were designated for hedge accounting.

As of September 30, 2013, our outstanding foreign currency derivatives include derivatives we use to (i) hedge CAD-denominated interest payments on CAD-denominated intercompany notes, (ii) hedge currency exchange risk associated with USD-denominated commodity purchases and sales in Canada and (iii) hedge currency exchange risk created by the use of USD-denominated commodity derivatives to hedge commodity price risk associated with CAD-denominated commodity purchases and sales.

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The following table summarizes our open forward exchange contracts as of September 30, 2013 (in millions):

| | | USD | CAD | Average Exchange Rate USD to CAD |
|---|---|---|---|---|
| **Forward exchange contracts that exchange CAD for USD:** | | | | |
| | 2013 | $ 283 | $ 292 | $1.00 - $1.03 |
| | 2014 | 104 | 108 | $1.00 - $1.03 |
| | 2015 | 9 | 9 | $1.00 - $1.04 |
| | | $ 396 | $ 409 | $1.00 - $1.03 |
| **Forward exchange contracts that exchange USD for CAD:** | | | | |
| | 2013 | $ 281 | $ 290 | $1.00 - $1.03 |
| | 2014 | 104 | 108 | $1.00 - $1.04 |
| | 2015 | 9 | 9 | $1.00 - $1.06 |
| | | $ 394 | $ 407 | $1.00 - $1.03 |
| **Net position by currency:** | | | | |
| | 2013 | $ 2 | $ 2 | |
| | 2014 | | | |
| | 2015 | | | |
| | | $ 2 | $ 2 | |

***Summary of Financial Impact***

We record all open derivatives on the balance sheet as either assets or liabilities measured at fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify as cash flow hedges, changes in fair value of the effective portion of the hedges are deferred in AOCI and recognized in earnings in the periods during which the underlying physical transactions are recognized in earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of the hedged items are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as cash flows from operating activities in our condensed consolidated statements of cash flows.

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A summary of the impact of our derivative activities recognized in earnings for the three and nine months ended September 30, 2013 and 2012 is as follows (in millions):

| | Three Months Ended September 30, 2013 | | | | Three Months Ended September 30, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Derivatives in Hedging Relationships | | | | Derivatives in Hedging Relationships | | | |
| Location of gain/(loss) | Gain/(loss) reclassified from AOCI into income (1) | Other gain/(loss) recognized in income | Derivatives Not Designated as a Hedge | Total | Gain/(loss) reclassified from AOCI into income (1) | Other gain/(loss) recognized in income | Derivatives Not Designated as a Hedge | Total |
| **Commodity Derivatives** | | | | | | | | |
| Supply and Logistics segment revenues | $ 109 | $ | $ (91) | $ 18 | $ 123 | $ | $ (102) | $ 21 |
| Facilities segment revenues | (2) | | | (2) | | | | |
| Field operating costs | | | 2 | 2 | | | 4 | 4 |
| **Interest Rate Derivatives** | | | | | | | | |
| Interest expense | (2) | 3 | | 1 | (2) | | | (2) |
| **Foreign Currency Derivatives** | | | | | | | | |
| Supply and Logistics segment revenues | | | | | | | 4 | 4 |
| Other income, net | 1 | | | 1 | 1 | | | 1 |
| **Total Gain/(Loss) on Derivatives Recognized in Net Income** | **$ 106** | **$ 3** | **$ (89)** | **$ 20** | **$ 122** | **$** | **$ (94)** | **$ 28** |

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| | Nine Months Ended September 30, 2013 | | | | Nine Months Ended September 30, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| | Derivatives in Hedging Relationships | | | | Derivatives in Hedging Relationships | | | |
| **Location of gain/(loss)** | **Gain/(loss) reclassified from AOCI into income (1)** | **Other gain/(loss) recognized in income** | **Derivatives Not Designated as a Hedge** | **Total** | **Gain/(loss) reclassified from AOCI into income (1)** | **Other gain/(loss) recognized in income** | **Derivatives Not Designated as a Hedge** | **Total** |
| **Commodity Derivatives** | | | | | | | | |
| Supply and Logistics segment revenues | $ 139 | $ | $ (34) | $ 105 | $ 62 | $ | $ 59 | $ 121 |
| Facilities segment revenues | (14) | | | (14) | 14 | (1) | | 13 |
| Purchases and related costs | | | | | 41 | | | 41 |
| Field operating costs | | | 7 | 7 | | | 2 | 2 |
| **Interest Rate Derivatives** | | | | | | | | |
| Interest expense | (5) | 3 | | (2) | (4) | (1) | | (5) |
| **Foreign Currency Derivatives** | | | | | | | | |
| Supply and Logistics segment revenues | | | | | | | 4 | 4 |
| Other income, net | 4 | | | 4 | 4 | | | 4 |
| **Total Gain/(Loss) on Derivatives Recognized in Net Income** | **$ 124** | **$ 3** | **$ (27)** | **$ 100** | **$ 117** | **$ (2)** | **$ 65** | **$ 180** |

(1) During the three months ended September 30, 2013, we reclassified losses of approximately $2 million from AOCI to Facilities segment revenues as a result of anticipated hedged transactions that are probable of not occurring. During the nine months ended September 30, 2013, we reclassified gains of approximately $3 million and losses of approximately $1 million from AOCI to Supply and Logistics segment revenues and Facilities segment revenues, respectively, as a result of anticipated hedged transactions that are probable of not occurring. All of our hedged transactions were deemed probable of occurring during the three and nine months ended September 30, 2012.

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The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of September 30, 2013 (in millions):

| | Asset Derivatives | | Liability Derivatives | |
|---|---|---|---|---|
| | **Balance Sheet Location** | **Fair Value** | **Balance Sheet Location** | **Fair Value** |
| **Derivatives designated as hedging instruments:** | | | | |
| Commodity derivatives | Other current assets | $ 3 | Other current assets | $ (13) |
| | Other long-term assets | 2 | | |
| Interest rate derivatives | Other long-term assets | 17 | Other current liabilities | (1) |
| Total derivatives designated as hedging instruments | | $ 22 | | $ (14) |
| **Derivatives not designated as hedging instruments:** | | | | |
| Commodity derivatives | Other current assets | $ 67 | Other current assets | $ (89) |
| | Other long-term assets | 7 | Other long-term assets | (7) |
| | Other current liabilities | 1 | Other current liabilities | (4) |
| | | | Other long-term liabilities | (1) |
| Foreign currency derivatives | Other current assets | 1 | | |
| Total derivatives not designated as hedging instruments | | $ 76 | | $ (101) |
| Total derivatives | | $ 98 | | $ (115) |

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of December 31, 2012 (in millions):

| | Asset Derivatives | | Liability Derivatives | |
|---|---|---|---|---|
| | **Balance Sheet Location** | **Fair Value** | **Balance Sheet Location** | **Fair Value** |
| **Derivatives designated as hedging instruments:** | | | | |
| Commodity derivatives | Other current assets | $ 45 | Other current assets | $ (23) |
| | Other long-term assets | 11 | Other long-term assets | (1) |
| Interest rate derivatives | | | Other long-term liabilities | (38) |
| Total derivatives designated as hedging instruments | | $ 56 | | $ (62) |
| **Derivatives not designated as hedging instruments:** | | | | |
| Commodity derivatives | Other current assets | $ 128 | Other current assets | $ (115) |
| | Other long-term assets | 1 | Other long-term assets | (3) |
| | Other current liabilities | 4 | Other current liabilities | (7) |
| | Other long-term liabilities | 2 | Other long-term liabilities | (2) |

| | | | | |
|---|---|---|---|---|
| Total derivatives not designated as hedging instruments | $ | 135 | $ | (127) |
| Total derivatives | $ | 191 | $ | (189) |

Our derivative transactions are governed through ISDA (International Swaps and Derivatives Association) master agreements and clearing brokerage agreements. These agreements include stipulations regarding the right of set off in the event that we or our counterparty default on our performance obligations. If a default were to occur, both parties have the right to net amounts payable and receivable into a single net settlement between parties.

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Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting arrangement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through clearing brokerage accounts and are subject to margin requirements as established by the respective exchange. On a daily basis, our account equity (consisting of the sum of our cash balance and the fair value of our open derivatives) is compared to our initial margin requirement resulting in the payment or return of variation margin. As of September 30, 2013, we had a net broker receivable of approximately $164 million (consisting of initial margin of $96 million increased by $68 million of variation margin that had been posted by us). As of December 31, 2012, we had a net broker receivable of approximately $41 million (consisting of initial margin of $69 million reduced by $28 million of variation margin that had been returned to us).

The following tables present information about derivatives and financial assets and liabilities that are subject to offsetting, including enforceable master netting arrangements at September 30, 2013 and December 31, 2012 (in millions):

| | September 30, 2013 | | December 31, 2012 | |
|---|---|---|---|---|
| | Derivative Asset Positions | Derivative Liability Positions | Derivative Asset Positions | Derivative Liability Positions |
| **Netting Adjustments:** | | | | |
| Gross position - asset/(liability) | $ 98 | $ (115) | $ 191 | $ (189) |
| Netting adjustment | (110) | 110 | (148) | 148 |
| Cash collateral paid | 164 | | 41 | |
| Net position - asset/(liability) | $ 152 | $ (5) | $ 84 | $ (41) |
| **Balance Sheet Location After Netting Adjustments:** | | | | |
| Other current assets | $ 133 | $ | $ 76 | $ |
| Other long-term assets | 19 | | 8 | |
| Other current liabilities | | (4) | | (3) |
| Other long-term liabilities | | (1) | | (38) |
| | $ 152 | $ (5) | $ 84 | $ (41) |

As of September 30, 2013, there was a net loss of approximately $104 million deferred in AOCI including tax effects. The deferred net loss recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged commodity transaction, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany balances. Of the total net loss deferred in AOCI at September 30, 2013, we expect to reclassify a net loss of approximately $28 million to earnings in the next twelve months. The remaining deferred loss of approximately $76 million is expected to be reclassified to earnings through 2045. A portion of these amounts are based on market prices as of September 30, 2013; thus, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives during the three and nine months ended September 30, 2013 and 2012 are as follows (in millions):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Commodity derivatives, net | $ 66 | $ 88 | $ 77 | $ 88 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Interest rate derivatives, net | | 12 | | 8 | | 64 | | (20) |
| Total | $ | 78 | $ | 96 | $ | 141 | $ | 68 |

At September 30, 2013 and December 31, 2012, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.  Although we may be required to post margin on our cleared derivatives as described above, we do not require our non-cleared derivative counterparties to post collateral with us.

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***Recurring Fair Value Measurements***

**Derivative Financial Assets and Liabilities**

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012 (in millions):

| | Fair Value as of September 30, 2013 | | | | Fair Value as of December 31, 2012 | | | |
|---|---|---|---|---|---|---|---|---|
| **Recurring Fair Value Measures (1)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Commodity derivatives | $ (11) | $ (22) | $ (1) | $ (34) | $ 1 | $ 35 | $ 4 | $ 40 |
| Interest rate derivatives | | 16 | | 16 | | (38) | | (38) |
| Foreign currency derivatives | | 1 | | 1 | | | | |
| Total | $ (11) | $ (5) | $ (1) | $ (17) | $ 1 | $ (3) | $ 4 | $ 2 |

(1) Derivative assets and liabilities are presented above on a net basis but do not include related cash margin deposits.

***Level 1***

Level 1 of the fair value hierarchy includes exchange-traded commodity derivatives such as futures and options. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets.

***Level 2***

Level 2 of the fair value hierarchy includes exchange-cleared commodity derivatives and over-the-counter commodity, interest rate and foreign currency derivatives that are traded in active markets. The fair value of these derivatives is based on broker price quotations which are corroborated with market observable inputs.

***Level 3***

Level 3 of the fair value hierarchy includes over-the-counter commodity derivatives that are traded in markets that are active but not sufficiently active to warrant level 2 classification in our judgment and certain physical commodity contracts. The fair value of our level 3 over-the-counter commodity derivatives is based on broker price quotations. The fair value of our level 3 physical commodity contracts is based on a valuation model utilizing broker-quoted forward commodity prices, and timing estimates, which involve management judgment. The significant unobservable inputs used in the fair value measurement of our level 3 derivatives are forward prices obtained from brokers. A significant increase (decrease) in these forward prices would result in a proportionately lower (higher) fair value measurement.

***Rollforward of Level 3 Net Asset/(Liability)***

The following table provides a reconciliation of changes in fair value of the beginning and ending balances for our derivatives classified as level 3 (in millions):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Beginning Balance | $ 4 | $ 36 | $ 4 | $ 12 |
| Total gains/(losses) for the period: | | | | |
| Included in earnings (1) | (4) | (9) | (1) | (1) |
| Included in other comprehensive income | | | | 3 |
| Settlements | (1) | (4) | (3) | (18) |
| Derivatives entered into during the period | | 1 | (1) | 23 |
| Transfers out of level 3 | | (14) | | (9) |
| Ending Balance | $ (1) | $ 10 | $ (1) | $ 10 |
| | | | | |
| Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods | $ (4) | $ (8) | $ (1) | $ 25 |

(1) We reported unrealized gains and losses associated with level 3 commodity derivatives in our condensed consolidated statements of operations as Supply and Logistics segment revenues.

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During the third quarter of 2012, we transferred commodity derivatives with an aggregate fair value of a $14 million gain from level 3 to level 2. These derivatives consist of over the counter derivatives that were previously valued using forward prices obtained from a broker and are now being valued using unadjusted quoted prices in active markets. Our policy is to recognize transfers between levels as of the beginning of the reporting period in which the transfer occurred.

During the second quarter of 2012, we transferred commodity derivatives with an aggregate fair value of a $5 million loss from level 3 to level 2. These derivatives consist of NGL derivatives that are cleared through the CME Clearport platform.  This transfer resulted from additional analysis regarding the CME s pricing methodology.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and will therefore be offset by gains or losses on the underlying transactions.

**Note 11 Commitments and Contingencies**

***Litigation***

*General.* In the ordinary course of business, we are involved in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable.  If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount.  We do not believe that the outcome of these legal proceedings, individually or in the aggregate and including the general and environmental legal proceedings described below, will have a material adverse effect on our financial condition, results of operations or cash flows.

*Pemex Exploración y Producción v. Big Star Gathering Ltd L.L.P. et al.* In two cases filed in the Texas Southern District Court in May 2011 and April 2012, Pemex Exploración y Producción ( PEP ) alleges that certain parties stole condensate from pipelines and gathering stations and conspired with U.S. companies (primarily in Texas) to import and market the stolen condensate.  PEP does not allege that Plains was part of any conspiracy, but that it dealt in the condensate only after it had been obtained by others and resold to Plains Marketing, L.P.  PEP seeks actual damages, attorney s fees, and statutory penalties from Plains Marketing, L.P.  At a hearing held on October 20, 2011, the Court ruled that Texas law (not Mexican law) governs the actions. In February 2013, the Court granted Plains Marketing, L.P. s motion to be dismissed from the April 2012 lawsuit and Plains Marketing, L.P. filed a motion for summary judgment in the May 2011 lawsuit. In October 2013, the Court issued an order in the May 2011 lawsuit granting summary judgment in favor of Plains Marketing, L.P. with respect to all of PEP s remaining claims against Plains Marketing, L.P.; shortly thereafter, PEP notified Plains Marketing, L.P. of its intent to appeal such ruling.

**Proposed Merger with PNG**

On September 13, 2013, Robert and Teresa Vicars, purported common unitholders of PNG, filed a class action petition on behalf of PNG s common unitholders and a derivative suit on behalf of PNG against PAA, PNG s general partner and the directors of PNG s general partner in the

152nd Judicial District of Harris County, Texas ( Vicars ). A similar class action complaint was filed against the same defendants, together with PAA GP LLC, Plains All American GP LLC and Plains AAP, L.P., on September 17, 2013, in the Court of Chancery of the State of Delaware by purported PNG common unitholder Stephen Ellman ( Ellman ). On November 14, 2013, a similar class action and derivate lawsuit was filed against the same defendants as named in the Vicars suit in the 129th Judicial District of Harris County, Texas by purported unitholder Thomas Barbee ( Barbee ). A fourth class action complaint for breach of fiduciary duties was filed against the same defendants as in the Ellman Suit on November 15, 2013, in the United States District Court for the Southern District of Texas Houston Division by purported unitholder Robert Evans, on behalf of himself and all others similarly situated ( Evans , and collectively with Vicars, Barbee and Ellman, the PNG Shareholder Suits ).

The PNG Shareholder Suits complaints allege, among other things, that the consideration offered by PAA is unfair and inadequate and that, by pursuing a transaction that is the result of an allegedly conflicted and unfair process, the defendants have breached their duties under PNG s partnership agreement as well as the implied covenant of good faith and fair dealing, and are engaging in self-dealing. These two lawsuits generally allege that: (i) the defendants are engaging in self-dealing, are not acting in good faith toward PNG, and have breached and are breaching their duties owed to PNG; (ii) the defendants are failing to properly value PNG and its various assets and operations and are ignoring or are not protecting against the numerous conflicts of interest arising out of the proposed transaction; and (iii) we, PNG s general partner, PNG and other of our affiliates have aided and abetted the defendant directors the purpose of advancing their own interests and/or assisting such directors in connection with their breaches of their respective duties. In addition, Vicars and Evans further include (i) purported derivative claims on behalf of PNG based on the alleged breaches of duties by the defendants and (ii) a claim that the defendants breached the implied covenant of good faith and fair dealing by engaging in a flawed merger process. In Barbee and Evans, the complaints allege, among other things, that the implied price per unit materially undervalues PNG and is unfair to its unitholders and that the S-4 registration statement filed by PNG was materially misleading. The PNG Shareholder Suits plaintiffs further allege that the defendants who are directors and officers of the general partner of PNG have breached their fiduciary duties of loyalty and care and the other defendants have aided and abetted in these alleged breaches. Based on these allegations, the plaintiffs generally seek to enjoin the defendants from proceeding with or consummating the merger. To the extent that the merger is implemented before relief is granted, plaintiffs seek to have the merger rescinded. The plaintiffs also seek money damages and attorneys fees.

We cannot predict the outcome of these or any other lawsuits that might be filed, nor can we predict the amount of time and expense that will be required to resolve these lawsuits. We intend to defend vigorously against these and any other actions. See Note 1 for a description of our proposal to acquire all of the outstanding common units of PNG that are held by unitholders other than us or our subsidiaries and to structure the proposed transaction as a merger with PNG.

***Environmental***

*General.* Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. These releases can result from unpredictable man-made or natural forces and may reach navigable waters or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At September 30, 2013, our estimated undiscounted reserve for environmental liabilities totaled approximately $99 million, of which approximately $13 million was classified as short-term and approximately $86 million was classified as long-term. At December 31, 2012, our reserve for environmental liabilities totaled approximately $96 million, of which approximately $13 million was classified as short-term and approximately $83 million was classified as long-term. The short- and long-term environmental liabilities referenced above are reflected in Accounts payable and accrued liabilities and Other long-term liabilities and deferred credits, respectively, on our condensed consolidated balance sheets. At September 30, 2013 and December 31, 2012, we had recorded receivables totaling approximately $10 million and $42 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our condensed consolidated balance sheets.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on information currently available to us and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional liabilities. Therefore, although we believe that the reserve is adequate, costs incurred may be in excess of the reserve and may potentially have a material adverse effect on our financial condition, results of operations or cash flows.

*Rainbow Pipeline Release.* During April 2011, we experienced a crude oil release of approximately 28,000 barrels of crude oil on a remote section of our Rainbow Pipeline located in Alberta, Canada. Since the release and through September 30, 2013, we spent approximately $70 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of September 30, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. On February 26, 2013, the Alberta Energy Regulator (formerly known as the Energy Resources Conservation Board of Alberta) ( AER ) issued a report detailing four enforcement actions against Plains Midstream Canada ULC ( PMC ) for failure to comply with certain regulatory requirements in connection with the release, including requirements related to operations and maintenance procedures, leak detection and response, backfill and compaction procedures and emergency response plan testing. PMC is in the process of taking appropriate actions necessary to respond to and comply with the enforcement actions set forth in the report, including the implementation of additional risk assessment procedures and the taking of other actions designed to minimize the risk that similar incidents occur in the future and enhance the effectiveness of PMC s response to any such future incidents. In addition, on April 23, 2013, the Alberta Crown Prosecutor filed civil charges under the Environmental Protection and Enhancement Act against PMC relating to the release. To date, PMC has not been assessed any fines or penalties related to this release; however, such fines or penalties may be assessed in the future and are not expected to be material.

*Rangeland Pipeline Release*. During June 2012, we experienced a crude oil release on a section of our Rangeland Pipeline located near Sundre, Alberta, Canada. Approximately 3,000 barrels were released into the Red Deer River and were contained downstream in the Gleniffer Reservoir. Remediation activities in the reservoir area were completed by June 30, 2012, remediation of the remaining impacted areas was completed by September 30, 2012 and interim closure was received from the applicable regulatory agencies. Monitoring will continue into 2013, and a long-term monitoring plan has been developed and implemented in accordance with regulatory requirements. Through September 30, 2013, we spent approximately $46 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of September 30, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. This release is currently under investigation by the AER, which also intends to perform an audit of PMC s operations. Although the AER s final investigation is not complete, on July 4, 2013, the AER issued a report detailing four enforcement actions against PMC citing failure to inspect water crossings, failure to complete an engineering assessment to determine suitability of continued operation of the Rangeland Pipeline, failure to maintain updated emergency response plans, and failure to conduct regular public awareness programs. The AER also issued an order under Section 22 of the Oil and Gas Conservation Act imposing additional regulatory requirements on PMC with respect to obtaining operating approvals under such Act and ordering audit of PMC s operations. To date, no fines or penalties have been assessed against PMC with respect to this release; however, it is possible that fines or penalties may be assessed against PMC in the future and are not expected to be material.

*Bay Springs Pipeline Release.* During February 2013, we experienced a crude oil release of approximately 120 barrels on a portion of one of our pipelines near Bay Springs, Mississippi. Most of the released oil was contained within our pipeline right of way, but some of the released oil entered a nearby waterway where it was contained with booms. The EPA has issued an administrative order requiring us to take various actions in response to the release, including remediation, reporting and other actions, and we may be subjected to a civil penalty. The aggregate cost to clean up and remediate the site was approximately $6 million, which has been recognized in Field operating costs on our condensed consolidated statement of operations.

*Kemp River Pipeline Release*. During May and June 2013, two separate releases were discovered on our Kemp River pipeline in Northern Alberta, Canada that, in the aggregate, resulted in the release of approximately 700 barrels of condensate and light crude oil. Clean-up and remediation activities are being conducted in cooperation with the applicable regulatory agencies. We estimate that the aggregate clean-up and remediation costs associated with these releases will be approximately $15 million which we have accrued to Field operating costs on our condensed consolidated statement of operations.

**Note 12 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 segment performance based on measures including segment profit and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative expenses. Each of the items above excludes depreciation and amortization. The following table reflects certain financial data for each segment for the periods indicated (in millions):

| | Transportation | | Facilities | | Supply and Logistics | | Total |
|---|---|---|---|---|---|---|---|
| **Three Months Ended September 30, 2013** | | | | | | | |
| Revenues: | | | | | | | |
| External Customers | $ | 179 | $ | 138 | $ | 10,386 | $ | 10,703 |
| Intersegment (1) | | 199 | | 142 | | | | 341 |
| Total revenues of reportable segments | $ | 378 | $ | 280 | $ | 10,386 | $ | 11,044 |
| Equity earnings in unconsolidated entities | $ | 19 | $ | | $ | | $ | 19 |
| Segment profit (2) (3) | $ | 198 | $ | 146 | $ | 64 | $ | 408 |
| Maintenance capital | $ | 29 | $ | 6 | $ | 7 | $ | 42 |

| Three Months Ended September 30, 2012 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Revenues: | | | | | | | | |
| External Customers | $ | 150 | $ | 156 | $ | 9,048 | $ | 9,354 |
| Intersegment (1) | | 214 | | 106 | | 1 | | 321 |
| Total revenues of reportable segments | $ | 364 | $ | 262 | $ | 9,049 | $ | 9,675 |
| Equity earnings in unconsolidated entities | $ | 9 | $ | | $ | | $ | 9 |
| Segment profit (2) (3) | $ | 184 | $ | 140 | $ | 142 | $ | 466 |
| Maintenance capital | $ | 26 | $ | 17 | $ | 4 | $ | 47 |

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| | Transportation | Facilities | Supply and Logistics | Total |
|---|---|---|---|---|
| **Nine Months Ended September 30, 2013** | | | | |
| Revenues: | | | | |
| External Customers | $ 517 | $ 558 | $ 30,542 | $ 31,617 |
| Intersegment (1) | 594 | 425 | 2 | 1,021 |
| Total revenues of reportable segments | $ 1,111 | $ 983 | $ 30,544 | $ 32,638 |
| Equity earnings in unconsolidated entities | $ 42 | $ | $ | $ 42 |
| Segment profit (2) (3) | $ 522 | $ 445 | $ 673 | $ 1,640 |
| Maintenance capital | $ 84 | $ 23 | $ 17 | $ 124 |
| | | | | |
| **Nine Months Ended September 30, 2012** | | | | |
| Revenues: | | | | |
| External Customers | $ 458 | $ 533 | $ 27,367 | $ 28,358 |
| Intersegment (1) | 585 | 252 | 1 | 838 |
| Total revenues of reportable segments | $ 1,043 | $ 785 | $ 27,368 | $ 29,196 |
| Equity earnings in unconsolidated entities | $ 25 | $ | $ | $ 25 |
| Segment profit (2) (3) | $ 516 | $ 344 | $ 544 | $ 1,404 |
| Maintenance capital | $ 78 | $ 34 | $ 11 | $ 123 |

(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market.

(2) Supply and Logistics segment profit includes interest expense (related to hedged inventory) of approximately $8 million and $3 million for the three months ended September 30, 2013 and 2012, respectively, and approximately $21 million and $9 million for the nine months ended September 30, 2013 and 2012, respectively.

(3) The following table reconciles segment profit to net income attributable to GP LLC (in millions):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Segment profit | $ 408 | $ 466 | $ 1,640 | $ 1,404 |
| Depreciation and amortization | (93) | (211) | (266) | (357) |
| Interest expense | (73) | (76) | (227) | (219) |
| Other income, net | 3 | 4 | 2 | 6 |
| Income tax expense | (9) | (13) | (79) | (44) |
| Net income | 236 | 170 | 1,070 | 790 |
| Net income attributable to noncontrolling interests | (235) | (169) | (1,067) | (788) |
| Net income attributable to GP LLC | $ 1 | $ 1 | $ 3 | $ 2 |

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**Note 13 Related Party Transactions**

For a complete discussion of our related party transactions, please read Note 13 to our 2012 Consolidated Financial Statements included in the Final Prospectus.

***Occidental Petroleum Corporation***

As of September 30, 2013, a subsidiary of Occidental Petroleum Corporation ( Oxy ) owned approximately 35% of our member interest and had a representative on our board of directors. In October 2013, in conjunction with PAGP s IPO, Oxy sold a portion of its interest, decreasing its ownership to approximately 25%. See Note 15 for further discussion of PAGP s IPO. During the three and nine months ended September 30, 2013 and 2012, we recognized sales and transportation revenues and purchased petroleum products from companies affiliated with Oxy. These transactions were conducted at posted tariff rates or prices that we believe approximate market. See detail below (in millions):

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2013 | 2012 | 2013 | 2012 |
| Revenues | $ 441 | $ 383 | $ 1,135 | $ 1,435 |
| Purchases and related costs | $ 229 | $ 138 | $ 604 | $ 416 |

We currently have a netting arrangement with Oxy. Our gross receivable and payable amounts with affiliates of Oxy were as follows (in millions):

| | September 30, 2013 | December 31, 2012 |
|---|---|---|
| Trade accounts receivable and other receivables | $ 307 | $ 231 |
| Accounts payable | $ 238 | $ 129 |

**Note 14 Impairments**

During the third quarter of 2012, we recognized losses on impairments of long-lived assets of approximately $125 million, primarily related to our Pier 400 terminal project, which is reflected in Depreciation and amortization on our condensed consolidated statement of operations. This project, which we acquired in late 2006 by virtue of our merger with Pacific Energy Partners, L.P., was to develop a deepwater petroleum import terminal at Pier 400 and Terminal Island in the Port of Los Angeles to handle marine receipts of crude oil and refinery feedstock. During the third quarter of 2012, we decided not to proceed with the development of this project. A number of factors contributed to the uncertainties with respect to financial returns and the determination not to proceed with the project, including project delays, the economic downturn, regulatory and permitting hurdles, a challenging refining environment in California and an industry shift in the outlook for availability of domestic crude oil. We assessed the recoverability of these long-lived assets and, where necessary, performed further analysis based on a projected discounted cash flow methodology. As a result of this impairment review, we wrote off a substantial portion of the carrying amount of these long-lived assets, except for the portion that we anticipate we will recover. These project assets were included in our Facilities segment.

During the three and nine months ended September 30, 2013, we recognized impairments of approximately $8 million and $15 million, respectively, related predominantly to assets taken out of service and canceled projects.

**Note 15 Subsequent Events**

***Initial Public Offering***

Through a series of transactions with PAGP s general partner and the owners of GP LLC prior to the closing of the IPO in October 2013, PAGP issued 473,647,679 Class B Shares to such owners and received a 100% managing member interest in GP LLC. Also prior to the IPO, certain owners of AAP (the Selling Owners ) sold a portion of their interests in AAP to PAGP in exchange for the right to receive an amount equal to the net proceeds of the IPO, resulting in PAGP s ownership of an approximate 21.8% limited partnership interest in AAP.

In October 2013, PAGP completed its IPO of 132,382,094 Class A Shares representing limited partner interests (including 4,382,094 Class A Shares issued in connection with the partial exercise of the underwriter s overallotment option),

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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. The net proceeds of the offering were distributed to the Selling Owners. The Class A Shares are listed on the New York Stock Exchange under the symbol PAGP. PAGP has elected to be treated as a corporation for U.S. federal income tax purposes.

***Administrative Agreement***

In conjunction with PAGP s IPO in October 2013, PAGP entered into an administrative agreement with PAA and certain of its affiliates, pursuant to which PAGP agreed upon certain aspects of its relationship with them, including, among other things (i) that if any business opportunity is presented to the parties to the agreement, PAA will have the first right to pursue such business opportunity, (ii) that GP LLC will employ such personnel as may be necessary to manage and operate the business, properties and assets of PAGP, its general partner and AAP, and AAP will pay GP LLC an annual fee (initially, $1.5 million per year, subject to adjustment as specified in the agreement) for such general and administrative services, (iii) that any direct expenses incurred by PAGP, its general partner or AAP (other than income taxes payable by PAGP), will be borne by AAP, (iv) that AAP will reimburse GP LLC for any additional expenses incurred by GP LLC and certain of its affiliates, and (v) that PAA has granted PAGP use of the name PAA and Plains and any associated or related marks.

***Plains GP Holdings, L.P. Long-Term Incentive Plan***

In connection with PAGP s IPO in October 2013, its general partner adopted the Plains GP Holdings, L.P. Long-Term Incentive Plan (the PAGP Plan ), which is intended to align the interests of PAGP s employees and directors with those of its shareholders by providing such employees and directors incentive compensation awards that reward achievement of targeted distribution levels and other business objectives. The PAGP Plan provides for awards of options, restricted shares, phantom shares and share appreciation rights. Certain awards may also include distribution equivalent rights, which, subject to applicable vesting criteria, entitle the grantee to a cash payment equal to the cash distribution paid on an outstanding Class A Share. The PAGP Plan authorizes the issuance of up to 10 million Class A Shares deliverable upon vesting. As of the date of this report, no awards had been granted under the PAGP Plan.

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**Item 2.** ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

**Introduction**

The historical condensed consolidated financial statements included in this Quarterly Report on Form 10-Q are those of Plains All American GP LLC ( GP LLC or the Predecessor ), a Delaware limited liability company formed on May 2, 2001 that serves as the managing general partner of Plains All American Pipeline, L.P. ( PAA ), a publicly traded Delaware limited partnership. PAA engages in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the processing, transportation, fractionation, storage and marketing of NGL. Through PAA s general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), it also owns and operates natural gas storage facilities.

Through a series of transactions with the owners of GP LLC prior to the IPO of Plains GP Holdings, L.P. ( PAGP ) on October 21, 2013, PAGP owns a 100% managing member interest in GP LLC. For further discussion regarding PAGP s IPO, please see Notes 1 and 15 to our condensed consolidated financial statements.

The following discussion analyzes the financial condition and results of operations of GP LLC. Such analysis should be read in conjunction with GP LLC s historical audited financial statements, and the notes thereto, included in the final prospectus dated October 15, 2013 (the Final Prospectus ) included in its Registration Statement on Form S-1, as amended (SEC File No. 333-190227). For ease of reference, we refer to the historical financial results of GP LLC 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 business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 12 for further discussion of our operating segments.

Our discussion and analysis includes the following:

- Executive Summary
- Acquisitions and Internal Growth Projects
- Results of Operations
- Liquidity and Capital Resources

- Off-Balance Sheet Arrangements
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

**Executive Summary**

During the first nine months of 2013, net income was approximately $1.070 billion, as compared to net income of approximately $790 million recognized during the first nine months of 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, contributions from recently completed organic growth projects and favorable unit margins in our Supply and Logistics segment.

The favorable unit margins in the Supply and Logistics segment were primarily driven by our NGL marketing operations, which benefited from improved market conditions and 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 during 2013, particularly narrower crude oil differentials.

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Other significant items during the period were:

- Decreased depreciation and amortization expense resulting from one-time asset impairment charges recognized during the comparative 2012 period;

- Increased income tax expense resulting from an increased proportion of earnings subject to Canadian federal and provincial taxes, primarily driven by the BP NGL Acquisition and the stronger performance from existing operations; and

- The receipt of net proceeds of approximately $1.1 billion from PAA s issuance of senior notes in August 2013 and the sale of approximately 7.2 million common units under PAA s continuous offering program.

**Acquisitions and Internal Growth Projects**

The following table summarizes our capital expenditures for acquisitions, internal growth projects and maintenance capital for the periods indicated (in millions):

| | Nine Months Ended September 30, 2013 | | Nine Months Ended September 30, 2012 | |
|---|---|---|---|---|
| Acquisition capital | $ | 19 | $ | 1,657 |
| Internal growth projects | | 1,253 | | 831 |
| Maintenance capital | | 124 | | 123 |
| Total | $ | 1,396 | $ | 2,611 |

***Internal Growth Projects***

The following table summarizes our more notable projects in progress during 2013 and the forecasted expenditures for the year ending December 31, 2013 (in millions):

| **Projects** | **2013** |
|---|---|
| Mississippian Lime Pipeline | $175 |
| Rainbow II Pipeline | 135 |
| Gulf Coast Pipeline | 110 |
| Yorktown Terminal Projects | 110 |
| Eagle Ford Area Pipeline Projects | 90 |

| | |
|---|---|
| Rail Terminal Projects (1) | 85 |
| White Cliffs Expansion | 75 |
| Cactus Pipeline | 70 |
| Eagle Ford JV Project | 60 |
| Fort Saskatchewan Facility Expansions | 60 |
| St. James Terminal Projects | 55 |
| Western Oklahoma Extension | 55 |
| Spraberry Area Pipeline Projects | 50 |
| PAA Natural Gas Storage (Multiple Projects) | 44 |
| Cushing Terminal Projects | 35 |
| Gulf Coast Gas Processing Facility Enhancements | 35 |
| Shafter Expansion | 30 |
| Other Projects (2) | 376 |
| | $1,650 |
| Potential Adjustments for Timing/Scope Refinement (3) | -$50 + $75 |
| Total Projected Expansion Capital Expenditures | $1,600 - $1,725 |

(1) Includes projects located at or near Tampa, CO, Bakersfield, CA and Van Hook, ND.

(2) Primarily multiple, smaller projects comprised of pipeline connections, upgrades and truck stations, new tank construction and refurbishing, pipeline linefill purchases and carry-over of capital from prior year projects.

(3) 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.

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**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 17 to our 2012 Consolidated Financial Statements included in the Final Prospectus for further discussion of how we evaluate segment performance.

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

| | Three Months Ended September 30, | | Favorable/ (Unfavorable) Variance | | Nine Months Ended September 30, | | Favorable/ (Unfavorable) Variance | |
|---|---|---|---|---|---|---|---|---|
| | 2013 | 2012 | $ | % | 2013 | 2012 | $ | % |
| Transportation segment profit | $ 198 | $ 184 | $ 14 | 8% | $ 522 | $ 516 | $ 6 | 1% |
| Facilities segment profit | 146 | 140 | 6 | 4% | 445 | 344 | 101 | 29% |
| Supply and Logistics segment profit | 64 | 142 | (78) | (55)% | 673 | 544 | 129 | 24% |
| Total segment profit | 408 | 466 | (58) | (12)% | 1,640 | 1,404 | 236 | 17% |
| Depreciation and amortization | (93) | (211) | 118 | 56% | (266) | (357) | 91 | 25% |
| Interest expense | (73) | (76) | 3 | 4% | (227) | (219) | (8) | (4)% |
| Other income, net | 3 | 4 | (1) | (25)% | 2 | 6 | (4) | (67)% |
| Income tax expense | (9) | (13) | 4 | 31% | (79) | (44) | (35) | (80)% |
| Net income | 236 | 170 | 66 | 39% | 1,070 | 790 | 280 | 35% |
| Net income attributable to noncontrolling interests | (235) | (169) | (66) | (39)% | (1,067) | (788) | (279) | (35)% |
| Net income attributable to GP LLC | $ 1 | $ 1 | $ | % | $ 3 | $ 2 | $ 1 | 50% |

***Analysis of Operating Segments***

**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)** | **Three Months Ended September 30, 2013** | **2012** | **Favorable/ (Unfavorable) Variance $** | **%** | **Nine Months Ended September 30, 2013** | **2012** | **Favorable/ (Unfavorable) Variance $** | **%** |
|---|---|---|---|---|---|---|---|---|
| Revenues (1) | | | | | | | | |
| Tariff activities | $ 329 | $ 315 | $ 14 | 4% | $ 959 | $ 907 | $ 52 | 6% |
| Trucking | 49 | 49 | | % | 152 | 136 | 16 | 12% |
| Total transportation revenues | 378 | 364 | 14 | 4% | 1,111 | 1,043 | 68 | 7% |
| | | | | | | | | |
| Costs and Expenses (1) | | | | | | | | |
| Trucking costs | (35) | (36) | 1 | 3% | (109) | (100) | (9) | (9)% |
| Field operating costs (excluding equity- indexed compensation expense) | (131) | (119) | (12) | (10)% | (402) | (343) | (59) | (17)% |
| Equity-indexed compensation expense - operations (2) | (3) | (3) | | % | (15) | (12) | (3) | (25)% |
| Segment general and administrative expenses (3) (excluding equity-indexed compensation expense) | (25) | (23) | (2) | (9)% | (74) | (73) | (1) | (1)% |
| Equity-indexed compensation expense - general and administrative (2) | (5) | (8) | 3 | 38% | (31) | (24) | (7) | (29)% |
| Equity earnings in unconsolidated entities | 19 | 9 | 10 | 111% | 42 | 25 | 17 | 68% |
| Segment profit | $ 198 | $ 184 | $ 14 | 8% | $ 522 | $ 516 | $ 6 | 1% |
| Maintenance capital | $ 29 | $ 26 | $ (3) | (12)% | $ 84 | $ 78 | $ (6) | (8)% |
| Segment profit per barrel | $ 0.58 | $ 0.57 | $ 0.01 | 2% | $ 0.52 | $ 0.55 | $ (0.03) | (5)% |

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| **Average Daily Volumes (in thousands of barrels per day) (4)** | **Three Months Ended September 30, 2013** | **2012** | **Favorable/ (Unfavorable) Variance Volumes** | **%** | **Nine Months Ended September 30, 2013** | **2012** | **Favorable/ (Unfavorable) Variance Volumes** | **%** |
|---|---|---|---|---|---|---|---|---|
| Tariff activities | | | | | | | | |
| Crude Oil Pipelines | | | | | | | | |
| All American | 40 | 38 | 2 | 5% | 39 | 31 | 8 | 26% |
| Bakken Area Systems | 136 | 127 | 9 | 7% | 130 | 133 | (3) | (2)% |
| Basin / Mesa | 731 | 678 | 53 | 8% | 712 | 676 | 36 | 5% |
| Capline | 147 | 159 | (12) | (8)% | 153 | 144 | 9 | 6% |
| Eagle Ford Area Systems | 119 | 26 | 93 | 358% | 81 | 17 | 64 | 376% |
| Line 63 / Line 2000 | 113 | 131 | (18) | (14)% | 113 | 126 | (13) | (10)% |
| Manito | 47 | 51 | (4) | (8)% | 46 | 59 | (13) | (22)% |
| Mid-Continent Area Systems | 256 | 281 | (25) | (9)% | 277 | 268 | 9 | 3% |
| Permian Basin Area Systems | 593 | 452 | 141 | 31% | 540 | 451 | 89 | 20% |
| Rainbow | 128 | 142 | (14) | (10)% | 125 | 147 | (22) | (15)% |
| Rangeland | 54 | 57 | (3) | (5)% | 59 | 60 | (1) | (2)% |
| Salt Lake City Area Systems | 131 | 156 | (25) | (16)% | 132 | 151 | (19) | (13)% |
| South Saskatchewan | 56 | 61 | (5) | (8)% | 50 | 60 | (10) | (17)% |
| White Cliffs | 22 | 18 | 4 | 22% | 22 | 18 | 4 | 22% |
| Other | 738 | 670 | 68 | 10% | 737 | 700 | 37 | 5% |
| NGL Pipelines | | | | | | | | |
| Co-Ed | 56 | 60 | (4) | (7)% | 55 | 41 | 14 | 34% |
| Other | 200 | 204 | (4) | (2)% | 190 | 121 | 69 | 57% |
| Refined Products Pipelines | 54 | 112 | (58) | (52)% | 88 | 114 | (26) | (23)% |
| Tariff activities total | 3,621 | 3,423 | 198 | 6% | 3,549 | 3,317 | 232 | 7% |
| Trucking | 120 | 107 | 13 | 12% | 113 | 103 | 10 | 10% |
| Transportation segment total | 3,741 | 3,530 | 211 | 6% | 3,662 | 3,420 | 242 | 7% |

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

(2) Equity-indexed compensation expense shown in the table above includes expenses associated with awards that will or may be settled in PAA units and awards that will or may be settled in cash.

(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 (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.

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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 tables above, our total Transportation segment revenues, net of trucking costs, and volumes increased for both the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012. The following factors contributed to the revenue and volume variances between the comparative periods:

- North American Crude Oil Production and Related Expansion Projects  For the three and nine-month comparative periods, 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 Basin and Mesa pipelines and our Permian Basin and Eagle Ford Area Systems. 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 $15 million and $30 million for the three and nine month periods of 2013 over the comparable three and nine month 2012 periods, respectively.

- Rate Changes  Revenues on our pipelines are impacted by various rate changes that 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 indexing that was effective July 1, 2012 had a favorable impact on revenues on our FERC regulated pipelines for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. The upward indexing effective July 1, 2013 also favorably impacted revenues on a majority of our FERC regulated pipelines; however, during the third quarter of 2013, we lowered our tariff rates on certain of our FERC regulated pipelines relative to 2012 rates, which more than offset the favorable impact of the upward indexing for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. Revenues for both the three and nine month were 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 $10 million to $15 million and $45 million to $50 million, respectively, for the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012.

- BP NGL Acquisition  We acquired pipelines through the BP NGL Acquisition completed on April 1, 2012. During the first quarter of 2013, we benefited from a full period of ownership of these assets, which contributed approximately $27 million of aggregate revenues and approximately 264,000 barrels per day during the three-month period ended March 31, 2013.

- 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 $5 million to $10 million and 5,000 to 10,000 barrels per day, respectively, for the three months ended September 30, 2013, and by approximately $15 million to $20 million and 15,000 to 20,000 barrels per day, respectively, for the nine months ended September 30, 2013.

- Rail Impact  Volumes primarily on our Manito and Rainbow pipelines and certain pipelines included in our Bakken Area Systems for the three- and nine-month comparable periods were negatively 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 $5 million and $15 million for the three and nine months ended

September 30, 2013, respectively, and that volumes decreased by approximately 20,000 to 30,000 barrels per day for each of the respective periods.

- 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 $4 million and $28 million, respectively, for the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 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, during each of the 2013 periods as compared to 2012 periods.

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Additional noteworthy volume and revenue variances for the comparative periods include (i) increased volumes and revenues on our All American pipeline for the three and nine month 2013 periods due to increased production in 2013 and maintenance activities at the production facilities during 2012, (ii) decreases on the Salt Lake City Area Systems and our Line 63 and Line 2000 pipelines for the three and nine month 2013 periods and on the Mid-Continent Area Systems for the three month 2013 period due to refinery maintenance issues and lower refinery demand for pipeline barrels; however, revenues on the Mid-Continent Area Systems and Line 63 pipeline were consistent with the prior year s quarter due to movements on higher tariff segments, (iii) increased trucking activity during the first nine months of 2013 due to increased demand for production transported to rail and hauls from pipeline disruptions and (iv) decreased volumes and revenues on our Refined Products Pipelines primarily due to the sale of certain of our refined products pipelines in July 2013.

*Field Operating Costs.* Field operating costs (excluding equity-indexed compensation expense) increased during the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 primarily due to (i) higher environmental response, remediation and related repair expenses associated with pipeline releases of approximately $2 million and $24 million, respectively, for the three and nine months ended September 30, 2013 over the three and nine months ended September 30, 2012, (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 during the nine months ended September 30, 2013 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 three-and nine-month periods.

*Equity-Indexed Compensation Expense.* On a consolidated basis across all segments, equity-indexed compensation expense decreased for the three months ended September 30, 2013 compared to the three months ended September 30, 2012, primarily due to the impact of a decrease in PAA s unit price during the three months ended September 30, 2013 compared to the impact of an increase in PAA s unit price during the three months ended September 30, 2012, partially offset by additional expense in the three months ended September 30, 2013 resulting from the increase in the level of PAA s distribution deemed probable of payment.

Equity-indexed compensation expense increased for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012, primarily due to (i) a more significant impact of the increase in PAA s unit price during the first nine months of 2013 compared to the impact of the increase during the first nine months of 2012, (ii) a greater number of units deemed probable of vesting for the first nine months of 2013 compared to the first nine months of 2012 and (iii) a higher average fair value per unit for those units deemed probable of vesting. See Note 14 to our 2012 Consolidated Financial Statements included in the Final Prospectus for further information regarding equity-indexed compensation plans.

*Maintenance Capital.* Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The increase in maintenance capital during the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 is primarily due to increased investment on pipeline integrity projects.

*Equity Earnings in Unconsolidated Entities*. The favorable variance in equity earnings in unconsolidated entities for the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 was primarily due to increased earnings from our equity method investments as a result of (i) increased throughput on the Eagle Ford and White Cliffs pipelines, as a result of increased production as discussed above, (ii) increased capacity related to vessel additions and increased rates on services provided by Settoon Towing and (iii) insurance proceeds received for partial repayment of losses incurred for an environmental liability related to an incident involving Settoon Towing LLC.

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**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, 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) | Three Months Ended September 30, 2013 | Three Months Ended September 30, 2012 | Favorable/ (Unfavorable) Variance $ | Favorable/ (Unfavorable) Variance % | Nine Months Ended September 30, 2013 | Nine Months Ended September 30, 2012 | Favorable/ (Unfavorable) Variance $ | Favorable/ (Unfavorable) Variance % |
|---|---|---|---|---|---|---|---|---|
| Revenues (1) | $ 257 | $ 236 | $ 21 | 9% | $ 787 | $ 626 | $ 161 | 26% |
| Natural gas sales (2) | 23 | 26 | (3) | (12)% | 196 | 159 | 37 | 23% |
| Storage related costs (natural gas related) | (4) | (4) | | % | (12) | (16) | 4 | 25% |
| Natural gas sales costs (2) | (19) | (25) | 6 | 24% | (184) | (152) | (32) | (21)% |
| Field operating costs (excluding equity-indexed compensation expense) | (92) | (72) | (20) | (28)% | (272) | (204) | (68) | (33)% |
| Equity-indexed compensation expense - operations (3) | | | | % | (2) | (2) | | % |
| Segment general and administrative expenses (excluding equity-indexed compensation expense) (4) | (15) | (16) | 1 | 6% | (48) | (48) | | % |
| Equity-indexed compensation expense - general and administrative (3) | (4) | (5) | 1 | 20% | (20) | (19) | (1) | (5)% |
| Segment profit | $ 146 | $ 140 | $ 6 | 4% | $ 445 | $ 344 | $ 101 | 29% |
| Maintenance capital | $ 6 | $ 17 | $ 11 | 65% | $ 23 | $ 34 | $ 11 | 32% |
| Segment profit per barrel | $ 0.41 | $ 0.42 | $ (0.01) | (2)% | $ 0.41 | $ 0.37 | $ 0.04 | 11% |

| Volumes (5) (6) | Three Months Ended September 30, 2013 | Three Months Ended September 30, 2012 | Favorable/ (Unfavorable) Variance Volumes | Favorable/ (Unfavorable) Variance % | Nine Months Ended September 30, 2013 | Nine Months Ended September 30, 2012 | Favorable/ (Unfavorable) Variance Volumes | Favorable/ (Unfavorable) Variance % |
|---|---|---|---|---|---|---|---|---|
| Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels) | 94 | 94 | | % | 94 | 88 | 6 | 7% |
| Rail load / unload volumes (average volumes in thousands of barrels per day) | 218 | | 218 | N/A | 221 | | 221 | N/A |
| Natural gas storage (average monthly capacity in billions of cubic feet) | 97 | 89 | 8 | 9% | 96 | 82 | 14 | 17% |
| NGL fractionation (average volumes in thousands of barrels per day) | 106 | 100 | 6 | 6% | 99 | 73 | 26 | 36% |
| Facilities segment total (average monthly volumes in millions of barrels) | 120 | 111 | 9 | 8% | 120 | 104 | 16 | 15% |

(1) Revenues and expenses include intersegment amounts.

(2) Natural gas sales and costs are attributable to the activities performed by PNG s commercial optimization group.

(3) Equity-indexed compensation expense shown in the table above includes expenses associated with awards that will or may be settled in PAA and PNG units and awards that will or may be settled in cash.

(4) 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.

(5) 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.

(6) 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 period and divided by the number of months in the period; (iii) natural gas storage 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 period and divided by the number of months in the period.

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 tables above, our Facilities segment revenues, less storage related costs and natural gas sales costs, and volumes increased for the three and nine months ended September 30, 2013 compared to the same periods of 2012. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our acquisitions and ongoing expansion activities as discussed below:

- Rail Terminal Acquisition and Expansion Projects The USD Rail Terminal Acquisition completed in December 2012 and related internal growth projects completed during the latter portion of 2012 expanded our rail loading and unloading fee-based activities. These rail load and unload activities contributed approximately $26 million and $76 million to the increase in total revenues for the three and nine months ended September 30, 2013 over the three and nine months ended September 30, 2012, respectively, and increased average throughput volumes by approximately 218,000 and 221,000 barrels per day during the respective comparative periods.

- NGL Storage, Fractionation and Gas Processing Activities We acquired NGL storage facilities, fractionation plants and related assets through the BP NGL Acquisition completed on April 1, 2012. During the first quarter of 2013, we benefited from a full period of ownership of these assets, which contributed approximately $66 million of aggregate revenues, 14 million barrels of average monthly capacity of NGL storage capacity, and 87,000 barrels per day of average NGL fractionation throughput during the three-month period ended March 31, 2013.

Excluding the impact of the acquisition as discussed above, our NGL storage, fractionation and gas processing revenues for the nine-month periods ended September 30, 2013 increased by approximately $15 million over the comparable nine-month 2012 period, primarily due to physical processing gains recognized at certain owned facilities. Volumes were relatively consistent for the three and nine month periods ended September 30, 2013 compared to the same 2012 periods.

- Other Expansion Projects We estimate that expansion projects that were completed in phases throughout recent years at some of our major terminal locations favorably impacted revenues for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 by approximately $14 million. Such projects included completed phases of expansions at our Cushing, Patoka, St. James and Yorktown terminals and new condensate stabilizers at our Gardendale terminal.

*Field Operating Costs.* Field operating costs (excluding equity-indexed compensation expense) increased during the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal Acquisitions. A portion of the increase for the three-month period was related to additional costs for integrity and other maintenance, particularly on the assets that were part of the BP NGL Acquisition. Additionally, the BP NGL Acquisition assets and operations typically have a higher ratio of operating costs to revenue than our historic operations in this segment.

*Maintenance Capital.* Maintenance capital consists of capital investments for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production and/or functionality of our existing assets. The decrease in maintenance capital during the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 is primarily due to completion of two major projects in 2012.

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**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. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. We do not anticipate that future changes in revenues 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 gathered 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)** | **Three Months Ended September 30,** | | **Favorable/ (Unfavorable) Variance** | | **Nine Months Ended September 30,** | | **Favorable/ (Unfavorable) Variance** | |
|---|---|---|---|---|---|---|---|---|
| **(in millions, except per barrel amounts)** | **2013** | **2012** | **$** | **%** | **2013** | **2012** | **$** | **%** |
| Revenues | $ 10,386 | $ 9,049 | $ 1,337 | 15% | $ 30,544 | $ 27,368 | $ 3,176 | 12% |
| Purchases and related costs (2) | (10,189) | (8,776) | (1,413) | (16)% | (29,439) | (26,414) | (3,025) | (11)% |
| Field operating costs (excluding equity- indexed compensation expense) | (103) | (101) | (2) | (2)% | (327) | (308) | (19) | (6)% |
| Equity-indexed compensation expense - operations (3) | | (1) | 1 | 100% | (2) | (2) | | % |
| Segment general and administrative expenses (excluding equity-indexed compensation expense) (4) | (25) | (24) | (1) | (4)% | (77) | (77) | | % |
| Equity-indexed compensation expense - general and administrative (3) | (5) | (5) | | % | (26) | (23) | (3) | (13)% |
| Segment profit | $ 64 | $ 142 | $ (78) | (55)% | $ 673 | $ 544 | $ 129 | 24% |
| Maintenance capital | $ 7 | $ 4 | $ (3) | (75)% | $ 17 | $ 11 | $ (6) | (55)% |
| Segment profit per barrel | $ 0.69 | $ 1.55 | $ (0.86) | (55)% | $ 2.33 | $ 2.06 | $ 0.27 | 13% |

| **Average Daily Volumes** | **Three Months Ended September 30,** | | **Favorable/ (Unfavorable) Variance** | | **Nine Months Ended September 30,** | | **Favorable/ (Unfavorable) Variance** | |
|---|---|---|---|---|---|---|---|---|
| **(in thousands of barrels per day)** | **2013** | **2012** | **Volumes** | **%** | **2013** | **2012** | **Volumes** | **%** |
| Crude oil lease gathering purchases | 856 | 811 | 45 | 6% | 855 | 808 | 47 | 6% |
| NGL sales | 145 | 179 | (34) | (19)% | 196 | 155 | 41 | 26% |
| Waterborne cargos | 4 | 5 | (1) | (20)% | 5 | 3 | 2 | 67% |
| Supply and Logistics segment total | 1,005 | 995 | 10 | 1% | 1,056 | 966 | 90 | 9% |

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(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 $8 million and $21 million for the three and nine months ended September 30, 2013 compared to $3 million and $9 million for the three and nine months ended September 30, 2012, respectively.

(3) Equity-indexed compensation expense shown in the table above includes expenses associated with awards that will or may be settled in PAA units and awards that will or may be settled in cash.

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(4) 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 benchmark price of crude oil ranged from approximately $96 to $112 per barrel and $82 to $100 per barrel during the three months ended September 30, 2013 and 2012, respectively, and from approximately $86 to $112 per barrel and $77 to $111 per barrel during the nine months ended September 30, 2013 and 2012, 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 the three and nine months ended September 30, 2013 and 2012 primarily from increased volumes in 2013.

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 for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012; however, such results decreased for the comparative three-month periods ended September 30, 2013 and 2012. Volumes also increased for the nine-month comparative period while volumes for the three-month 2013 period were relatively consistent with volumes in the three-month 2012 period. The following factors contributed to the variances in revenues and volumes between the comparative periods:

• 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 previously 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 for favorable crude oil margins resulting in lower contributions from our crude oil activities.

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. (Please read Business of Plains All American Pipeline, L.P. Impact of Commodity Price Volatility and Dynamic Market Conditions on PAA s Business Model included in the Final Prospectus for further discussion regarding PAA s business model, including diversification and utilization of its asset base among varying demand- and supply-driven markets.)

- NGL Marketing Operations Revenues from our NGL marketing operations increased during the three and nine months ended September 30, 2013 as compared to the three and nine months ended September 30, 2012 primarily due to more favorable market prices and higher demand related to (i) increases in export activity that reduced overall product availability in the market and (ii) petrochemical demand as well as more favorable supply contracts. Additionally, NGL margins during the nine-month 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. The nine-month 2013 period further benefited from higher demand related to heating requirements during an extended winter season.

NGL sales volumes decreased during the three months ended September 30, 2013 compared to the three months ended September 30, 2012 primarily due to excess Canadian inventory in 2012 acquired through the BP NGL Acquisition, unexpected refinery shutdowns in the third quarter of 2013 and a reduction in the amount of field supply purchased. However, NGL sales volumes increased over the comparative nine-month periods primarily due to increased demand as discussed above, as well as the impact from our BP NGL Acquisition completed on April 1, 2012.

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*Impact from Derivative Activities.* The mark-to-market valuation of our derivative activities impacted our net revenues for the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 as shown in the table below (in millions):

| | Three Months Ended September 30, 2013 | Three Months Ended September 30, 2012 | Variance | Nine Months Ended September 30, 2013 | Nine Months Ended September 30, 2012 | Variance |
|---|---|---|---|---|---|---|
| Gains/(losses) from derivative activities (1) | $ (57) | $ (36) | $ (21) | $ (6) | $ (19) | $ 13 |

(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 10 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

*Field Operating Costs.* Field operating costs (excluding equity-indexed compensation expense) increased in the three and nine months ended September 30, 2013 compared to the three and nine months ended September 30, 2012 primarily related to increased lease gathered volumes, particularly in West Texas and Oklahoma.

*Equity-Indexed Compensation Expense.* On a consolidated basis, equity-indexed compensation expense decreased for the three months ended Sept