PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
November 06, 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: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**76-0582150** (I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas (Address of principal executive offices)	**77002** (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. x Yes o 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 x	Accelerated filer o
Non-accelerated filer o (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 October 31, 2013, there were 342,950,166 Common Units outstanding.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except units)

	September 30, 2013	December 31, 2012
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 33	$ 24
Trade accounts receivable and other receivables, net	3,562	3,563
Inventory	1,198	1,209
Other current assets	352	351
Total current assets	5,145	5,147
PROPERTY AND EQUIPMENT	12,245	11,142
Accumulated depreciation	(1,638)	(1,499)
	10,607	9,643
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	534	586
Total assets	$ 20,267	$ 19,235
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 4,049	$ 3,822
Short-term debt	619	1,086
Other current liabilities	343	275
Total current liabilities	5,011	5,183
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	308	310
Other long-term liabilities and deferred credits	554	586
Total long-term liabilities	7,572	6,906
COMMITMENTS AND CONTINGENCIES (NOTE 12)		

PARTNERS CAPITAL				
Common unitholders (342,950,166 and 335,283,874 units outstanding, respectively)		6,873		6,388
General partner		277		249
Total partners capital excluding noncontrolling interests		7,150		6,637
Noncontrolling interests		534		509
Total partners capital		7,684		7,146
Total liabilities and partners capital	$	20,267	$	19,235

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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	210	265	356
Total costs and expenses	10,407	9,107	30,284	27,335
OPERATING INCOME	296	247	1,333	1,023
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)	(72)	(74)	(224)	(214)
Other income, net	3	4	2	6
INCOME BEFORE TAX	246	186	1,153	840
Current income tax expense	(17)	(10)	(69)	(32)
Deferred income tax benefit/(expense)	8	(3)	(10)	(11)
NET INCOME	237	173	1,074	797
Net income attributable to noncontrolling interests	(6)	(8)	(22)	(23)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 231	$ 165	$ 1,052	$ 774
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 133	$ 89	$ 764	$ 554
GENERAL PARTNER	$ 98	$ 76	$ 288	$ 220
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.38	$ 0.27	$ 2.23	$ 1.71
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.38	$ 0.27	$ 2.22	$ 1.70
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	343	329	340	322
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	345	331	342	325

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	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)	
Net income	$ 237	$ 173	$ 1,074	$ 797
Other comprehensive income/(loss)	39	84	(99)	35
Comprehensive income	276	257	975	832
Comprehensive income attributable to noncontrolling interests	(7)	(5)	(27)	(15)
Comprehensive income attributable to Plains	$ 269	$ 252	$ 948	$ 817

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2012	$ (120)	$ 200	$ 80
Reclassification adjustments	(124)		(124)
Deferred gain on cash flow hedges, net of tax	140		140
Currency translation adjustments		(115)	(115)
Total period activity	16	(115)	(99)
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 PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Nine Months Ended September 30, 2013	2012
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 1,074	$ 797
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	265	356
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	152	(453)
Net cash provided by operating activities	1,594	880
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 under commercial paper program (Note 7)	319	
Proceeds from the issuance of senior notes	699	1,247
Repayments of senior notes		(500)
Net proceeds from the issuance of common units (Note 9)	400	812
Net proceeds from the issuance of PNG common units	40	
Distributions paid to common unitholders (Note 9)	(585)	(502)
Distributions paid to general partner (Note 9)	(270)	(208)
Distributions paid to noncontrolling interests	(37)	(36)
Other financing activities	(25)	(11)
Net cash (used in)/provided by financing activities	(242)	1,501
Effect of translation adjustment on cash	(3)	1
Net increase in cash and cash equivalents	9	6

Cash and cash equivalents, beginning of period		24		26
Cash and cash equivalents, end of period	$	33	$	32
Cash paid for:				
Interest, net of amounts capitalized	$	230	$	207
Income taxes, net of amounts refunded	$	19	$	58

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	Partners
	Units	Amount	Partner	Interests	Interests	Capital
			(unaudited)			
Balance at December 31, 2012	335.3	$ 6,388	$ 249	$ 6,637	$ 509	$ 7,146
Net income		764	288	1,052	22	1,074
Distributions		(585)	(270)	(855)	(37)	(892)
Issuance of common units	7.2	392	8	400		400
Issuance of common units under LTIP	0.8	4		4		4
Units tendered by employees to satisfy tax withholding obligations	(0.3)	(15)		(15)		(15)
Equity-indexed compensation expense		24	4	28	3	31
Distribution equivalent right payments		(4)		(4)		(4)
Issuance of PNG common units		8		8	32	40
Other		(1)		(1)		(1)
Other comprehensive income/(loss)		(102)	(2)	(104)	5	(99)
Balance at September 30, 2013	343.0	$ 6,873	$ 277	$ 7,150	$ 534	$ 7,684

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. As used in this Form 10-Q and unless the context indicates otherwise, the terms Partnership, Plains, PAA, we, us, our, ours and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries. Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. On October 21, 2013, Plains GP Holdings, L.P., a Delaware limited partnership that has elected to be treated as a corporation for U.S. federal income tax purposes (PAGP) completed its initial public offering. As a result of the offering, PAGP currently owns an approximate 21.8% limited partner interest in Plains AAP, L.P. The remaining limited partner interests in Plains AAP, L.P. continue to be held by the owners of PAA s general partner entities immediately prior to PAGP s initial public offering. In addition to its ownership of PAA GP LLC, Plains AAP, L.P. also owns all of the incentive distribution rights in PAA. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P. s general partner. References to our general partner, as the context requires, include any or all of PAA GP LLC, Plains AAP, L.P. and Plains All American GP LLC.

We engage 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 our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also own and operate natural gas storage facilities. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 13 for further discussion of our operating segments.

Potential Acquisition of Publicly-held Common Units of PNG

On October 22, 2013, we announced our entry into a definitive agreement and plan of merger (the Merger Agreement) with PNG that provides for a merger whereby PNG will become our wholly-owned subsidiary through a unit-for-unit exchange (the Merger). Under the terms of the Merger Agreement, we will issue 0.445 PAA common units for each outstanding PNG common unit held by unitholders other than us, 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 us and consummation of the transaction is expected to result in the issuance of approximately 14.7 million PAA common units. In connection with the closing of the Merger, the owners of our general partner have agreed to reduce their incentive distribution rights under our 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 us) 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. We own 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, we have agreed to vote our common units and subordinated units in favor of the Merger. We anticipate that the Merger will close in the latter half of the fourth quarter of 2013 or the first quarter of 2014, and that the previously announced quarterly distribution of $0.3575 per PNG common unit payable to holders of record of such units on November 1, 2013 will be 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
GAAP	=	Generally accepted accounting principles in the United States
ICE	=	IntercontinentalExchange

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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.
SEC	=	Securities and Exchange Commission
USD	=	United States dollar
WTI	=	West Texas Intermediate
WTS	=	West Texas Sour

Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and notes thereto should be read in conjunction with our 2012 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as set forth by 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 the interim periods have been reflected. All significant intercompany transactions have been eliminated in consolidation. Certain reclassifications have been made to information from previous years to conform to the current presentation. The condensed consolidated balance sheet data as of December 31, 2012 was derived from audited financial statements, but does not include all disclosures required by GAAP. The results of operations for the three and nine months ended September 30, 2013 should not be taken as indicative of results to be expected for the entire year.

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

Note 2 Recent Accounting Pronouncements

Other than as discussed below and in our 2012 Annual Report on Form 10-K, 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 11, 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.

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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 11, 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.

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, we 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. We expect to close the balance of the transaction during the fourth quarter of 2013.

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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 11 for discussion of our derivative and risk management activities.

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

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(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
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
Commercial paper notes, bearing a weighted-average interest rate of 0.25% at September 30, 2013 **(2)**	319	
5.63% senior notes due December 2013 **(4)**	250	250
Other	4	2
Total short-term debt	619	1,086
LONG-TERM DEBT		
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)**:		
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	7,018	6,320
Total debt **(2)** **(3)** **(6)**	$ 7,637	$ 7,406

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(1) In August 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 our 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) PNG classifies 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) Our $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, we 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.

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(6) Our 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. Our 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, we established a commercial paper program under which we 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 our commercial paper program reduce the available capacity under these facilities.

Credit Facilities

In August 2013, we amended our senior secured hedged inventory facility and senior unsecured revolving credit facility agreements 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, PNG extended the maturity date of its senior unsecured revolving credit facility and GO Bond term loans by one year to August 2017.

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 $12.7 billion and $8.5 billion, respectively. Total repayments under our credit agreements and commercial paper program were approximately $13.2 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 PNG s 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.

Note 8 Net Income Per Limited Partner Unit

Basic and diluted net income per limited partner unit is determined pursuant to the two-class method for Master Limited Partnerships as prescribed in the FASB guidance. The two-class method is an earnings allocation formula that is used to determine earnings to our general partner, common unitholders and participating securities according to distributions pertaining to the current period s net income and participation rights in undistributed earnings. Under this method, all earnings are allocated to our general partner, common unitholders and participating securities based on their respective rights to receive distributions, regardless of whether those earnings would actually be distributed during a particular period from an economic or practical perspective.

The Partnership calculates basic and diluted net income per limited partner unit by dividing net income attributable to Plains, after deducting the amount allocated to the general partner s interest, incentive distribution rights (IDRs) and participating securities, by the basic and diluted weighted-average number of limited partner units outstanding during the period. Participating securities include LTIP awards that have vested DERs, which entitle the grantee to a cash payment equal to the cash distribution paid on our outstanding common units.

Diluted net income per limited partner unit is computed based on the weighted average number of units plus the effect of dilutive potential units outstanding during the period using the two-class method. Our LTIP awards that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for a complete discussion of our LTIP awards including specific discussion regarding DERs.

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The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three and nine months ended September 30, 2013 and 2012 (in millions, except per unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Basic Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 231	$ 165	$ 1,052	$ 774
General partner s incentive distribution **(1)**	(95)	(74)	(272)	(208)
General partner 2% ownership **(1)**	(3)	(2)	(16)	(12)
Net income available to limited partners	133	89	764	554
Undistributed earnings allocated and distributions to participating securities **(1)**	(1)	(1)	(5)	(3)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 132	$ 88	$ 759	$ 551
Basic weighted average number of limited partner units outstanding	343	329	340	322
Basic net income per limited partner unit	$ 0.38	$ 0.27	$ 2.23	$ 1.71
Diluted Net Income per Limited Partner Unit				
Net income attributable to Plains	$ 231	$ 165	$ 1,052	$ 774
General partner s incentive distribution **(1)**	(95)	(74)	(272)	(208)
General partner 2% ownership **(1)**	(3)	(2)	(16)	(12)
Net income available to limited partners	133	89	764	554
Undistributed earnings allocated and distributions to participating securities **(1)**	(1)	(1)	(4)	(3)
Net income available to limited partners in accordance with application of the two-class method for MLPs	$ 132	$ 88	$ 760	$ 551
Basic weighted average number of limited partner units outstanding	343	329	340	322
Effect of dilutive securities: Weighted average LTIP units	2	2	2	3
Diluted weighted average number of limited partner units outstanding	345	331	342	325
Diluted net income per limited partner unit	$ 0.38	$ 0.27	$ 2.22	$ 1.70

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(1) We calculate net income available to limited partners based on the distributions pertaining to the current period s net income. After adjusting for the appropriate period s distributions, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner, limited partners and participating securities in accordance with the contractual terms of the partnership agreement and as further prescribed under the two-class method.

The terms of our partnership agreement limit the general partner s incentive distribution to the amount of available cash, which, as defined in the partnership agreement, is net of reserves deemed appropriate. As such, IDRs are not allocated undistributed earnings or distributions in excess of earnings in the calculation of net income per limited partner unit. If, however, undistributed earnings were allocated to our IDRs beyond amounts distributed to them under the terms of the partnership agreement, basic and diluted earnings per limited partner unit as reflected in the table above would be impacted as follows:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2013		2012		2013		2012	
Basic net income per limited partner unit impact	$		$		$	(0.23)	$	(0.04)
Diluted net income per limited partner unit impact	$		$		$	(0.23)	$	(0.04)

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Note 9 Partners Capital and Distributions

PAA Distributions

The following table details the distributions paid during or pertaining to the first nine months of 2013, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

Date Declared	Date Paid or To Be Paid	Common Units	Distributions Paid General Partner Incentive	Distributions Paid General Partner 2%	Total	Distributions per limited partner unit
October 1, 2013	November 14, 2013 (1)	$ 206	$ 95	$ 4	$ 305	$ 0.6000
July 8, 2013	August 14, 2013	$ 201	$ 91	$ 4	$ 296	$ 0.5875
April 8, 2013	May 15, 2013	$ 195	$ 86	$ 4	$ 285	$ 0.5750
January 7, 2013	February 14, 2013	$ 189	$ 81	$ 4	$ 274	$ 0.5625

(1) Payable to unitholders of record at the close of business on November 1, 2013, for the period July 1, 2013 through September 30, 2013.

PAA Continuous Offering Program

In May 2013, we entered into an additional equity distribution agreement with several financial institutions pursuant to which we may offer and sell, through our 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, we issued an aggregate of approximately 7.2 million common units under our continuous offering program, generating net proceeds of approximately $400 million, including our general partner s proportionate capital contribution, 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), we issued approximately 0.5 million common units during the first nine months of 2013, net of units tendered by employees for tax withholding obligations.

Noncontrolling Interests in Subsidiaries

As of September 30, 2013, noncontrolling interests in subsidiaries consisted of (i) an approximate 37% interest in PNG and (ii) a 25% interest in SLC Pipeline LLC.

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.

As a result of PNG s common unit issuances under its continuous offering program, we recorded an increase in noncontrolling interest of approximately $32 million and an increase to our partners capital of approximately $8 million. These increases represent the portion of the proceeds attributable to the respective ownership interests in PNG, adjusted for the impact of the dilution of our ownership interest.

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The following table sets forth the impact upon net income attributable to Plains giving effect to the changes in our ownership interest in PNG, which is recognized in partners capital (in millions):

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
Net income attributable to Plains	$ 231	$ 165	$ 1,052	$ 774
Transfers to the noncontrolling interests:				
Increase in capital from sale of PNG units	2		8	
Change from net income attributable to Plains and net transfers to the noncontrolling interests	$ 233	$ 165	$ 1,060	$ 774

Noncontrolling Interests Rollforward

The following table reflects the changes in the noncontrolling interests in partners capital (in millions):

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Beginning balance	$ 509	$ 524
Net income attributable to noncontrolling interests	22	23
Distributions to noncontrolling interests	(37)	(36)
Equity-indexed compensation expense	3	3
Distribution equivalent right payments		(1)
Issuance of PNG common units	32	
Other comprehensive income/(loss):		
Reclassification adjustments	6	(7)
Net deferred loss on cash flow hedges	(1)	(1)
Ending balance	$ 534	$ 505

Note 10 Equity-Indexed Compensation Plans

We refer to the PAA and PNG LTIP Plans, Special PAA Awards and Class B Units of Plains AAP, L.P. collectively as our Equity-indexed compensation plans. For additional discussion of our equity-indexed compensation plans and awards, see Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K.

Class B Units of Plains AAP, L.P. The following table contains a summary of Class B Units of Plains AAP, L.P.:

Grant Date

	Reserved for Future Grants (1)	Outstanding (1)	Outstanding Units Earned (1)	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 the initial public offering of PAGP and the recapitalization of Plains AAP, L.P. on October 21, 2013, the number of Class B Units of Plains AAP, L.P. was adjusted; as such, as of such date, the number of Class B Units of Plains AAP, L.P. 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.

(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, we granted 143,000 Special PAA Awards 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 will vest on the date that we pay an annualized distribution of $2.40 per unit, provided that PNG s quarterly distribution remains at least $1.43 (annualized) per unit. Any unvested Special PAA Awards that remain outstanding on December 31, 2020 will be forfeited.

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PAA and PNG LTIP Awards. Our 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 Plains AAP, L.P.

(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, we granted 2.4 million equity-classified phantom unit awards and 1.5 million liability-classified phantom unit awards under our 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 we pay 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 we pay 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 we pay 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.

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 our 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.

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Note 11 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 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.

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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 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.

We have 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 our 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 our August 2013 senior notes issuance, we terminated five thirty-year forward starting swaps. 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 8/3/2014	0.95%	Cash flow hedge

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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.

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	(1)			(1)
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**	**$ 123**	**$**	**$ (94)**	**$ 29**

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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)	(1)	(1)		(2)
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**	**$ 120**	**$ (2)**	**$ 65**	**$ 183**

(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		9		63		(19)
Total	$	78	$	97	$	140	$	69

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 12 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). A third class action complaint for breach of fiduciary duties was filed against the same defendants as in the Ellman Suit on October 2, 2013, in the United States District Court for the Southern District of Texas Houston Division by purported unitholder The Duckpond CRT UTD 2/14/03, on behalf of itself and all others similarly situated (Duckpond).

The Vicars and Ellman complaints allege, among other things, that the consideration offered by us 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, Ellman further includes (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 Duckpond, the complaint alleges, among other things, that the implied price per unit materially undervalues PNG and is unfair to its unitholders. The Duckpond plaintiff further alleges 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. In Duckpond, that plaintiff also seeks a constructive trust in favor of the purported class of PNG unitholders upon any benefits improperly received by the defendants.

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.

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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 13 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):

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	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

	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

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(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. For further discussion, see Analysis of Operating Segments under Item 7 of our 2012 Annual Report on Form 10-K.

(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.

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

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Segment profit	$ 408	$ 466	$ 1,640	$ 1,404
Depreciation and amortization	(93)	(210)	(265)	(356)
Interest expense	(72)	(74)	(224)	(214)
Other income, net	3	4	2	6
Income tax expense	(9)	(13)	(79)	(43)
Net income	237	173	1,074	797
Net income attributable to noncontrolling interests	(6)	(8)	(22)	(23)
Net income attributable to Plains	$ 231	$ 165	$ 1,052	$ 774

Note 14 Related Party Transactions

See Note 14 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Occidental Petroleum Corporation

As of September 30, 2013, a subsidiary of Occidental Petroleum Corporation (Oxy) owned approximately 35% of our general partner interest and had a representative on the board of directors of Plains All American GP LLC. In October 2013, in conjunction with the PAGP initial public offering, Oxy sold a portion of its interest in our general partner, decreasing its ownership to approximately 25%. 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, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 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,	December 31,

	2013	2012
Trade accounts receivable and other receivables	$ 307	$ 231
Accounts payable	$ 238	$ 129

Note 15 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.

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2012 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the condensed consolidated financial statements and related notes that are contained in Part I, Item 1 of this Quarterly Report on Form 10-Q.

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

Company Overview

We engage in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as the processing, transportation, fractionation, storage and marketing of NGL. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P., we also own and operate natural gas storage facilities. We were formed in 1998, and our operations are conducted directly and indirectly through our operating subsidiaries and are managed through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics.

Overview of Operating Results, Capital Investments and Significant Activities

During the first nine months of 2013, net income attributable to Plains was approximately $1.052 billion, or $2.22 per diluted limited partner unit, as compared to net income attributable to Plains of approximately $774 million, or $1.70 per diluted limited partner unit, 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 our existing operations; and

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

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(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.

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 18 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K 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)	(210)	117	56%	(265)	(356)	91	26%
Interest expense	(72)	(74)	2	3%	(224)	(214)	(10)	(5)%
Other income, net	3	4	(1)	(25)%	2	6	(4)	(67)%
Income tax expense	(9)	(13)	4	31%	(79)	(43)	(36)	(84)%
Net income	237	173	64	37%	1,074	797	277	35%
Net income attributable to noncontrolling interests	(6)	(8)	2	25%	(22)	(23)	1	4%
Net income attributable to Plains	$ 231	$ 165	$ 66	40%	$ 1,052	$ 774	$ 278	36%
Net income attributable to Plains:								
Basic net income per limited partner unit	$ 0.38	$ 0.27	$ 0.11	41%	$ 2.23	$ 1.71	$ 0.52	30%
Diluted net income per limited partner unit	$ 0.38	$ 0.27	$ 0.11	41%	$ 2.22	$ 1.70	$ 0.52	31%
Basic weighted average units outstanding	343	329	14	4%	340	322	18	6%
Diluted weighted average units outstanding	345	331	14	4%	342	325	17	5%

Non-GAAP Financial Measures

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

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

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The following table sets forth non-GAAP financial measures that are reconciled to the most directly comparable GAAP measures (in millions):

	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 %
Net income	$ 237	$ 173	$ 64	37%	$ 1,074	$ 797	$ 277	35%
Add:								
Depreciation and amortization	93	210	(117)	(56)%	265	356	(91)	(26)%
Income tax expense	9	13	(4)	(31)%	79	43	36	84%
Interest expense	72	74	(2)	(3)%	224	214	10	5%
EBITDA	$ 411	$ 470	$ (59)	(13)%	$ 1,642	$ 1,410	$ 232	16%
Selected Items Impacting Comparability of EBITDA								
Gains/(losses) from derivative activities net of inventory valuation adjustments (1)	$ (59)	$ (31)	$ (28)	(90)%	$ (9)	$ (18)	$ 9	50%
Equity-indexed compensation expense (2)	(12)	(12)		%	(51)	(50)	(1)	(2)%
Net gain/(loss) on foreign currency revaluation (3)	2	11	(9)	(82)%	5	(6)	11	183%
Significant acquisition-related expenses				%		(13)	13	100%
Selected Items Impacting Comparability of EBITDA	$ (69)	$ (32)	$ (37)	(116)%	$ (55)	$ (87)	$ 32	37%
EBITDA	$ 411	$ 470	$ (59)	(13)%	$ 1,642	$ 1,410	$ 232	16%
Selected Items Impacting Comparability of EBITDA	69	32	37	116%	55	87	(32)	(37)%
Adjusted EBITDA	$ 480	$ 502	$ (22)	(4)%	$ 1,697	$ 1,497	$ 200	13%
Adjusted EBITDA	$ 480	$ 502	$ (22)	(4)%	$ 1,697	$ 1,497	$ 200	13%
Interest expense	(72)	(74)	2	3%	(224)	(214)	(10)	(5)%
Maintenance capital (4)	(42)	(47)	5	11%	(124)	(123)	(1)	(1)%
Current income tax expense	(17)	(10)	(7)	(70)%	(69)	(32)	(37)	(116)%
Equity earnings in unconsolidated entities, net of distributions	(6)	1	(7)	(700)%	(7)	2	(9)	(450)%
Distributions to noncontrolling interests (5)	(13)	(12)	(1)	(8)%	(38)	(36)	(2)	(6)%
Implied DCF	$ 330	$ 360	$ (30)	(8)%	$ 1,235	$ 1,094	$ 141	13%
Less: Distributions paid (5)	(305)	(259)			(886)	(743)		
DCF Excess/(Shortage) (6)	$ 25	$ 101			$ 349	$ 351		

(1) We use derivative instruments for risk management purposes and our related processes include specific identification of hedging instruments to an underlying hedged transaction. Although we identify an underlying transaction for each derivative instrument we enter into, there may not be an accounting hedge relationship between the instrument and the underlying transaction. In the course of evaluating our results of operations, we identify the earnings that were recognized during the period related to derivative instruments for which the identified underlying transaction does not occur in the current period and exclude the related gains and losses in determining Adjusted EBITDA. We also exclude the impact of inventory valuation adjustments.

(2) Our total equity-indexed compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a

selected item impacting comparability as the dilutive impact of the outstanding awards is included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting comparability. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for a comprehensive discussion regarding our equity-indexed compensation plans.

(3) During the three and nine months ended September 30, 2013 and 2012, there were fluctuations in the value of the Canadian dollar to the U.S dollar, resulting in net gains and losses that were not related to our core operating results for the period and were thus classified as selected items impacting comparability. See Note 11 to our condensed consolidated financial statements for further discussion regarding our currency exchange rate risk hedging activities.

(4) Maintenance capital expenditures are defined as 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.

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

(6) Excess DCF is retained to establish reserves for future distributions, capital expenditures and other partnership purposes.

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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)	**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 (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 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.

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.

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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.

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.

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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 unit price during the three months ended September 30, 2013 compared to the impact of an increase in 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 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 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 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for further information regarding our 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.

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,**		**Favorable/ (Unfavorable) Variance**		**Nine Months Ended September 30,**		**Favorable/ (Unfavorable) Variance**	
	2013	**2012**	**$**	**%**	**2013**	**2012**	**$**	**%**
Revenues (1)	$ 257	$ 236	$ 21	9%	$ 787	$ 626		