UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 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 April 30, 2013, there were 339,093,053 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)

	March 31, 2013	December 31, 2012
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 24	$ 24
Trade accounts receivable and other receivables, net	3,701	3,563
Inventory	1,031	1,209
Other current assets	384	351
Total current assets	5,140	5,147
PROPERTY AND EQUIPMENT	11,431	11,142
Accumulated depreciation	(1,548)	(1,499)
	9,883	9,643
OTHER ASSETS		
Goodwill	2,520	2,535
Linefill and base gas	704	707
Long-term inventory	244	274
Investments in unconsolidated entities	392	343
Other, net	557	586
Total assets	$ 19,440	$ 19,235
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 4,073	$ 3,822
Short-term debt	689	1,086
Other current liabilities	260	275
Total current liabilities	5,022	5,183
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $15 and $15, respectively	6,010	6,010
Long-term debt under credit facilities and other	321	310
Other long-term liabilities and deferred credits	598	586
Total long-term liabilities	6,929	6,906
COMMITMENTS AND CONTINGENCIES (NOTE 12)		

PARTNERS CAPITAL				
Common unitholders (337,739,553 and 335,283,874 units outstanding, respectively)		6,724		6,388
General partner		261		249
Total partners capital excluding noncontrolling interests		6,985		6,637
Noncontrolling interests		504		509
Total partners capital		7,489		7,146
Total liabilities and partners capital	$	19,440	$	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 March 31, 2013 (unaudited)	2012
REVENUES		
Supply and Logistics segment revenues	$ 10,224	$ 8,877
Transportation segment revenues	173	150
Facilities segment revenues	223	191
Total revenues	10,620	9,218
COSTS AND EXPENSES		
Purchases and related costs	9,437	8,502
Field operating costs	340	249
General and administrative expenses	106	94
Depreciation and amortization	82	60
Total costs and expenses	9,965	8,905
OPERATING INCOME	655	313
OTHER INCOME/(EXPENSE)		
Equity earnings in unconsolidated entities	11	7
Interest expense (net of capitalized interest of $9 and $9, respectively)	(77)	(65)
Other income, net		2
INCOME BEFORE TAX	589	257
Current income tax expense	(46)	(17)
Deferred income tax expense	(7)	(3)
NET INCOME	536	237
Net income attributable to noncontrolling interests	(8)	(7)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 528	$ 230
NET INCOME ATTRIBUTABLE TO PLAINS:		
LIMITED PARTNERS	$ 433	$ 162
GENERAL PARTNER	$ 95	$ 68
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.28	$ 0.52
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.27	$ 0.51
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	336	314
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	339	316

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 March 31, 2013	2012
	(unaudited)	
Net income	$ 536	$ 237
Other comprehensive income/(loss)	(46)	59
Comprehensive income	490	296
Comprehensive income attributable to noncontrolling interests	(5)	(3)
Comprehensive income attributable to Plains	$ 485	$ 293

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	(5)		(5)
Deferred gain on cash flow hedges, net of tax	27		27
Currency translation adjustments		(68)	(68)
Total period activity	22	(68)	(46)
Balance at March 31, 2013	$ (98)	$ 132	$ 34

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)

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 536	$ 237
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	82	60
Equity compensation expense	51	39
Gain on sales of linefill and base gas		(12)
Net cash paid for terminated interest rate and foreign currency hedging instruments		(23)
Other	(1)	(4)
Changes in assets and liabilities, net of acquisitions	311	20
Net cash provided by operating activities	979	317
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(31)	(21)
Change in restricted cash		(1,632)
Additions to property, equipment and other	(363)	(263)
Cash received for sales of linefill and base gas	9	30
Cash paid for purchases of linefill and base gas	(13)	(17)
Investment in unconsolidated entities	(48)	
Proceeds from sales of assets	2	13
Net cash used in investing activities	(444)	(1,890)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on PAA s revolving credit facility	(72)	184
Net repayments on PAA s hedged inventory facility	(335)	(75)
Net borrowings/(repayments) on PNG s credit agreements	27	(5)
Proceeds from the issuance of senior notes		1,247
Net proceeds from the issuance of common units (Note 9)	131	455
Distributions paid to common unitholders (Note 9)	(189)	(159)
Distributions paid to general partner (Note 9)	(85)	(66)
Distributions paid to noncontrolling interests	(12)	(12)
Other financing activities		(9)
Net cash provided by/(used in) financing activities	(535)	1,560
Effect of translation adjustment on cash		1
Net increase/(decrease) in cash and cash equivalents		(12)
Cash and cash equivalents, beginning of period	24	26
Cash and cash equivalents, end of period	$ 24	$ 14
Cash paid for:		
Interest, net of amounts capitalized	$ 70	$ 78
Income taxes, net of amounts refunded	$ 9	$ 28

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 Partner	Partners Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Partners Capital
	Units	Amount				
			(unaudited)			
Balance at December 31, 2012	335.3	$ 6,388	$ 249	$ 6,637	$ 509	$ 7,146
Net income		433	95	528	8	536
Distributions		(189)	(85)	(274)	(12)	(286)
Issuance of common units	2.4	128	3	131		131
Equity compensation expense		7		7	1	8
Distribution equivalent right payments		(1)		(1)		(1)
Other comprehensive loss		(42)	(1)	(43)	(3)	(46)
Other					1	1
Balance at March 31, 2013	337.7	$ 6,724	$ 261	$ 6,985	$ 504	$ 7,489

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. 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.

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
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

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

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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 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 months ended March 31, 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 three months ended March 31, 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 three months ended March 31, 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.

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.

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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 risks 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 March 31, 2013 and December 31, 2012, we had received approximately $157 million and $173 million, respectively, of advance cash payments from third parties to mitigate credit risk. Furthermore, at March 31, 2013 and December 31, 2012, we had received approximately $677 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, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables against each other) that cover a significant portion of our transactions and also serve to mitigate credit risk.

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 March 31, 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 March 31, 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 Acquisitions and Dispositions

For a full discussion of the acquisitions included in the pro forma results below, see Note 3 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K.

Pro Forma Results

Selected unaudited pro forma results of operations for the three months ended March 31, 2012, assuming the BP NGL Acquisition, USD Rail Terminal Acquisition and our other 2012 acquisitions had occurred on January 1, 2012, are presented below (in millions, except per unit amounts):

	Three Months Ended

		March 31, 2012
Total revenues	$	10,064
Net income attributable to Plains	$	230
Limited partner interest in net income attributable to Plains	$	166
Net income per limited partner unit:		
Basic	$	0.51
Diluted	$	0.51

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 March 31, 2013 and December 31, 2012, these assets were classified as held for sale on our condensed consolidated balance sheets (in Other current assets). We expect the transaction to close during the second or third quarter of 2013, subject to the satisfaction of customary closing conditions.

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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 (barrels and natural gas volumes in thousands and carrying value in millions):

	March 31, 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	9,173	barrels	$ 780	$ 85.03	9,492	barrels	$ 737	$ 77.64
NGL	2,974	barrels	132	$ 44.38	9,472	barrels	388	$ 40.96
Natural gas (2)	26,452	Mcf	88	$ 3.33	20,374	Mcf	60	$ 2.94
Other	N/A		31	N/A	N/A		24	N/A
Inventory subtotal			1,031				1,209	
Linefill and base gas								
Crude oil	9,946	barrels	582	$ 58.52	9,919	barrels	583	$ 58.78
NGL	1,400	barrels	68	$ 48.57	1,400	barrels	70	$ 50.00
Natural gas (2)	15,755	Mcf	54	$ 3.43	15,755	Mcf	54	$ 3.43
Linefill and base gas subtotal			704				707	
Long-term inventory								
Crude oil	2,035	barrels	155	$ 76.17	1,962	barrels	149	$ 75.94
NGL	2,221	barrels	89	$ 40.07	3,238	barrels	125	$ 38.60
Long-term inventory subtotal			244				274	
Total			$ 1,979				$ 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.

(2) The volumetric ratio of Mcf of natural gas to crude Btu equivalent is 6:1; thus, natural gas volumes can be approximately converted to barrels by dividing by 6.

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:				
Foreign currency translation adjustments	(6)	(3)	(1)	(10)
Purchase price accounting adjustments and other (1)	(5)			(5)
Balance at March 31, 2013	$ 886	$ 1,168	$ 466	$ 2,520

(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.

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Note 7 Debt

Debt consisted of the following (in millions):

	March 31, 2013		December 31, 2012	
SHORT-TERM DEBT				
Credit Facilities :				
PAA senior secured hedged inventory facility, bearing a weighted-average interest rate of 1.3% and 1.6% at March 31, 2013 and December 31, 2012, respectively	$	325	$	665
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 1.5% and 2.4% at March 31, 2013 and December 31, 2012, respectively (1)		18		92
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% at both March 31, 2013 and December 31, 2012 (2)		93		77
5.63% senior notes due December 2013 (3)		250		250
Other		3		2
Total short-term debt		689		1,086
LONG-TERM DEBT				
Senior notes, net of unamortized discounts of $15 at both March 31, 2013 and December 31, 2012.		6,010		6,010
Credit Facilities and Other:				
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% at both March 31, 2013 and December 31, 2012 (2)		116		105
PNG GO Bond term loans, bearing a weighted-average interest rate of 1.5% at both March 31, 2013 and December 31, 2012		200		200
Other		5		5
Total long-term debt		6,331		6,320
Total debt (1) (2) (4)	$	7,020	$	7,406

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(1) We classify as short-term certain borrowings under our PAA senior unsecured revolving credit 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.

(2) 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.

(3) Our $250 million 5.63% senior notes will mature in December 2013 and are thus classified as short-term at March 31, 2013 and December 31, 2012.

(4) Our fixed-rate senior notes (including current maturities) had a face value of approximately $6.3 billion at both March 31, 2013 and December 31, 2012. We estimated the aggregate fair value of these notes as of March 31, 2013 and December 31, 2012 to be approximately $7.2 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 facilities and agreements approximates fair value as interest rates reflect current market rates. The fair value estimates for both our senior notes and credit facilities and agreements are based upon observable market data and are classified within level 2 of the fair value hierarchy.

Letters of Credit

In connection with our supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. At March 31, 2013 and December 31, 2012, we had outstanding letters of credit of approximately $56 million and $24 million, respectively.

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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.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three months ended March 31, 2013 and 2012 (in millions, except per unit data):

	Three Months Ended March 31,			
	2013		2012	
Basic Net Income per Limited Partner Unit				
Net income attributable to Plains	$	528	$	230
Less: General partner s incentive distribution (1)		(86)		(65)
Less: General partner 2% ownership (1)		(9)		(3)
Net income available to limited partners		433		162
Less: Undistributed earnings allocated and distributions to participating securities (1)		(3)		
Net income available to limited partners in accordance with application of the two-class method for MLPs	$	430	$	162
Basic weighted average number of limited partner units outstanding		336		314
Basic net income per limited partner unit	$	1.28	$	0.52
Diluted Net Income per Limited Partner Unit				
Net income attributable to Plains	$	528	$	230
Less: General partner s incentive distribution (1)		(86)		(65)

Less: General partner 2% ownership (1)		(9)		(3)
Net income available to limited partners		433		162
Less: Undistributed earnings allocated and distributions to participating securities (1)		(1)		
Net income available to limited partners in accordance with application of the two-class method for MLPs	$	432	$	162
Basic weighted average number of limited partner units outstanding		336		314
Effect of dilutive securities: Weighted average LTIP units		3		2
Diluted weighted average number of limited partner units outstanding		339		316
Diluted net income per limited partner unit	$	1.27	$	0.51

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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 March 31, 2013	Three Months Ended March 31, 2012
Basic net income per limited partner unit impact	$ (0.34)	$
Diluted net income per limited partner unit impact	$ (0.34)	$

Note 9 Partners Capital and Distributions

PAA Distributions

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

			Distributions Paid			
		Common	General Partner			Distributions per limited
Date Declared	Date Paid or To Be Paid	Units	Incentive	2%	Total	partner unit
April 8, 2013	May 15, 2013 (1)	$ 195	$ 86	$ 4	$ 285	$ 0.5750
January 7, 2013	February 14, 2013	$ 189	$ 81	$ 4	$ 274	$ 0.5625

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(1) Payable to unitholders of record at the close of business on May 3, 2013, for the period January 1, 2013 through March 31, 2013.

PAA Continuous Offering Program

During the first quarter of 2013, we issued an aggregate of approximately 2.4 million common units under our continuous offering program, generating net proceeds of approximately $131 million, including our general partner s proportionate capital contribution, net of approximately

$1 million of commissions to our sales agents. The net proceeds from sales were used for general partnership purposes.

Noncontrolling Interests in Subsidiaries

As of March 31, 2013, noncontrolling interests in subsidiaries consisted of (i) an approximate 36% 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. Sales of such common units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by the sales agent and PNG. Under the terms of the agreement, PNG has the option to sell common units to the sales agent as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, PNG will enter into a separate terms agreement with the sales agent.

During the first quarter of 2013, PNG issued an aggregate of approximately 57,000 common units under this agreement, generating net proceeds of approximately $1.2 million, including our proportionate capital contribution for our general partner interest.

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Noncontrolling Interests Rollforward

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

	Three Months Ended March 31, 2013	2012
Beginning balance	$ 509	$ 524
Net income attributable to noncontrolling interests	8	7
Distributions to noncontrolling interests	(12)	(12)
Equity compensation expense	1	1
Other	1	
Other comprehensive income/(loss):		
Reclassification adjustments	2	(6)
Net deferred gain/(loss) on cash flow hedges	(5)	2
Ending balance	$ 504	$ 516

Note 10 Equity Compensation Plans

For additional discussion of our equity compensation 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.:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value of Outstanding Class B Units (1) (in millions)
Balance at December 31, 2012	17,875	182,125	130,250	$ 44
Granted	(3,500)	3,500		6
Earned	N/A	N/A	26,000	N/A
Balance at March 31, 2013	14,375	185,625	156,250	$ 50

(1) Of the grant date fair value, less than $1 million was recognized as expense during the three months ended March 31, 2013.

Class B Units of PNGS GP LLC. During July 2010, the Board of Directors of PNG s general partner authorized the issuance of 165,000 Class B units of PNGS GP LLC (PNGS GP LLC Class B Units). At December 31, 2012, 74,250 PNGS GP LLC Class B Units were outstanding. In February 2013, PNG s general partner determined that the PNGS GP LLC Class B Units were not serving their intended purpose due to the low likelihood of achieving the PNG distribution performance benchmarks required for vesting, which ranged from $2.00 to $2.70 per common unit. As a result, all 74,250 of the existing PNGS GP LLC Class B Unit awards were canceled. In order to encourage the retention of the holders of such canceled awards and provide them with long-term performance incentives, our general partner authorized the issuance of Special PAA

Awards to such officers, as further discussed below.

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.

PAA LTIP Awards. In addition to the Special PAA Awards described above, in February 2013, we also granted 2.7 million equity-classified phantom unit awards and 1.2 million liability-classified phantom unit awards under our 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. Certain of these equity-classified awards include DERs that will vest in one-third increments upon achieving the referenced distribution performance thresholds, without regard to the minimum service period. 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 2017 distribution date and vest dependent on PAA paying annualized quarterly distributions ranging from $2.30 per common unit to $2.50 per common unit. None of the liability-classified awards include DERs.

Other Equity Compensation Information. 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)			PNG Units (2) (3)		
	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	$	47.04	0.4	$	17.42
Cancelled or forfeited	(0.1)	$	31.47		$	
Outstanding at March 31, 2013	10.0	$	34.24	1.3	$	17.47

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(1) Amounts do not include Class B Units of Plains AAP, L.P.

(2) Amounts do not include PNGS GP LLC Class B Units.

(3) Amounts include PNG Transaction Grants.

The table below summarizes the expense recognized and the value of vesting (settled both in units and cash) related to our equity compensation plans (in millions):

	Three Months Ended March 31,	
	2013	2012
Equity compensation expense	$ 51	$ 39
LTIP unit-settled vestings	$	$ 24
LTIP cash-settled vestings	$	$ 36
DER cash payments	$ 2	$ 2

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 March 31, 2013, net derivative positions related to these activities included:

- An approximate 319,400 barrels per day net long position (total of 9.6 million barrels) associated with our crude oil purchases, which was unwound ratably during April 2013 to match monthly average pricing.

- A net short spread position averaging approximately 14,600 barrels per day (total of 13.7 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through November 2015. 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.

- Approximately 12,800 barrels per day on average (total of 3.2 million barrels) of WTS/WTI crude oil basis swaps through December 2013, which hedge anticipated sales of crude oil (WTI). These derivatives are grade spreads between two different grades of crude oil. Our use of these derivatives does not expose us to outright price risk.

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- An average of 2,800 barrels per day (total of 1.0 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are based on a percentage of WTI through March 2014.

- A long swap position of approximately 2.9 Bcf through April 2016 related to both anticipated base gas requirements.

- A short swap position of approximately 26.5 Bcf through December 2013 related to anticipated sales of natural gas.

Storage Capacity Utilization We own approximately 97 million barrels 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 if the market structure is backwardated. As of March 31, 2013, we used derivatives to manage the risk of not utilizing approximately 2.1 million barrels per month of storage capacity through 2013. These positions are a combination of calendar spread options and futures contracts. These positions involve no outright price exposure, but instead enable us to profitably use the capacity to store hedged crude oil.

Inventory Storage From time to time, we elect to purchase and store crude oil, NGL and refined products inventory in conjunction with our supply and logistics activities. When we purchase and store inventory, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of March 31, 2013, we had derivatives totaling approximately 7.8 million barrels hedging our inventory. These positions are a combination of futures, swaps and option contracts.

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 March 31, 2013, our PLA hedges included (i) a net short position consisting of crude oil futures and swaps for an average of approximately 1,900 barrels per day (total of 1.9 million barrels) through December 2015, (ii) a long put option position of approximately 0.2 million barrels through December 2013 and (iii) a long call option position of approximately 0.5 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 purchase of natural gas and the subsequent sale of the individual specification products. As of March 31, 2013, we had a long natural gas position of approximately 16.1 Bcf through December 2014, a short propane position of approximately 2.8 million barrels through December 2014, a short butane position of approximately 0.8 million barrels through December 2014 and a short WTI position of approximately 0.3 million barrels through December 2014. In addition, we had a long power position of 0.7 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 March 31, 2013, AOCI includes deferred losses of approximately $123 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.

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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 March 31, 2013 (notional amounts in millions):

Hedged Transaction	Number and Types of Derivatives Employed	Notional Amount	Expected Termination Date	Average Rate Locked	Accounting Treatment
Anticipated debt offering	5 forward starting swaps (30-year)	$ 125	6/16/2014	3.39%	Cash flow hedge
Anticipated debt offering	10 forward starting swaps (30-year)	$ 250	6/15/2015	3.60%	Cash flow hedge

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 swaps have an aggregate notional amount of $100 million with an average fixed rate of 0.95%. Two of these swaps terminate in June 2014 and the remaining swap terminates in August 2014. These swaps are designated as cash flow hedges.

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 March 31, 2013, AOCI includes net deferred gains of approximately $4 million that relate to foreign currency derivatives that were designated for hedge accounting.

As of March 31, 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 March 31, 2013 (in millions):

		USD	CAD	Average Exchange Rate USD to CAD
Forward exchange contracts that exchange CAD for USD:				
	2013	$ 7	$ 7	$1.00 to $1.00
Forward exchange contracts that exchange USD for CAD:				
	2013	$ 151	$ 152	$0.99 to $1.00
	2014	1	1	$1.00 to $1.00
		$ 152	$ 153	$0.99 to $1.00
Net position by currency:				
	2013	$ 144	$ 145	

2014	1	1
	$ 145	$ 146

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 impact earnings. For our interest rate swaps that qualify as fair value hedges, changes in the fair value of the derivatives are recognized in earnings each period. Additionally, the change in fair value of the hedged item, attributable to the hedged risk, is recognized as a basis adjustment to the hedged item and is also 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 months ended March 31, 2013 and 2012 is as follows (in millions):

	Three Months Ended March 31, 2013			
	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 (2)**	**Total**
Commodity Derivatives				
Supply and Logistics segment revenues	$ 10	$	$ 35	$ 45
Facilities segment revenues	(4)			(4)
Field operating costs			1	1
Interest Rate Derivatives				
Interest expense	(2)			(2)
Foreign Currency Derivatives				
Other income, net	1			1
Total Gain on Derivatives Recognized in Net Income	**$ 5**	**$**	**$ 36**	**$ 41**

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	Three Months Ended March 31, 2012			
	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 (2)	Total
Commodity Derivatives				
Supply and Logistics segment revenues	$ 37	$ (3)	$ (38)	$ (4)
Facilities segment revenues	12			12
Purchases and related costs	4		1	5
Field operating costs			2	2
Interest Rate Derivatives				
Interest expense	(2)	1		(1)
Foreign Currency Derivatives				
Supply and Logistics segment revenues			1	1
Other income, net	1			1
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ 52**	**$ (2)**	**$ (34)**	**$ 16**

(1) During the three months ended March 31, 2013, we reclassified a gain of approximately $2 million from AOCI to Supply and Logistics segment revenues 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 months ended March 31, 2012.

(2) Includes realized and unrealized gains and losses for derivatives that did not qualify or were not designated for hedge accounting during the period.

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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 March 31, 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	$	55	Other current assets	$	(48)
	Other long-term assets		10	Other long-term assets		(2)
Interest rate derivatives	Other long-term assets		3	Other current liabilities		(1)
				Other long-term liabilities		(23)
Total derivatives designated as hedging instruments		$	68		$	(74)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	121	Other current assets	$	(88)
	Other long-term assets		2	Other long-term assets		(4)
				Other current liabilities		(1)
				Other long-term liabilities		(1)
Foreign currency derivatives				Other current liabilities		(1)
Total derivatives not designated as hedging instruments		$	123		$	(95)
Total derivatives		$	191		$	(169)

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)

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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.

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 March 31, 2013, we had a net broker receivable of approximately $82 million (consisting of initial margin of $70 million increased by $12 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 March 31, 2013 and December 31, 2012:

	March 31, 2013		December 31, 2012	
	Derivative Asset Positions	Derivative Liability Positions	Derivative Asset Positions	Derivative Liability Positions
Netting Adjustments:				
Gross Position - Asset/(Liability)	$ 191	$ (169)	$ 191	$ (189)
Netting Adjustment	(142)	142	(148)	148
Cash Collateral Paid/(Received)	82		41	
Net Position - Asset/(Liability)	$ 131	$ (27)	$ 84	$ (41)
Balance Sheet Location After Netting Adjustments:				
Other Current Assets	$ 122	$	$ 76	$
Other Long-Term Assets	9		8	
Other Current Liabilities		(3)		(3)
Other Long-Term Liabilities		(24)		(38)
	$ 131	$ (27)	$ 84	$ (41)

As of March 31, 2013, there was a net loss of approximately $98 million deferred in AOCI including tax effects. The total amount of 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 March 31, 2013, we expect to reclassify a net gain of approximately $21 million to earnings in the next twelve months. Of the remaining deferred loss in AOCI, a net loss of approximately $2 million is expected to be reclassified to earnings prior to 2016 with the remaining deferred loss of approximately $117 million being reclassified to earnings through 2045. A portion of these amounts are based on market prices at the current period end, 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 months ended March 31, 2013 and 2012 are as follows (in millions):

	For the Three Months Ended March 31,			
	2013		2012	
Commodity derivatives, net	$	3	$	25
Interest rate derivatives, net		19		51
Total	$	22	$	76

At March 31, 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 March 31, 2013 and December 31, 2012 (in millions):

	Fair Value as of March 31, 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	$	$ 43	$ 1	$ 44	$ 1	$ 35	$ 4	$ 40
Interest rate derivatives		(21)		(21)		(38)		(38)
Foreign currency derivatives		(1)		(1)				
Total	$	$ 21	$ 1	$ 22	$ 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, options and swaps. 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 Assets

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 March 31,	
	2013	**2012**
Beginning Balance	$ 4	$ 12
Unrealized gains/(losses):		
Included in earnings (1)		(4)
Included in other comprehensive income		3
Settlements	(3)	(12)
Derivatives entered into during the period		3
Transfers out of level 3		
Ending Balance	$ 1	$ 2
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$	$ (1)

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(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.

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.

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.

Rainbow Pipeline Release. On April 29, 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 March 31, 2013, we spent approximately $70 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of March 31, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. On February 26, 2013, the Energy Resources Conservation Board of Alberta (ERCB) 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 Ministry of Environment and Sustainable Resource Development 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 reasonably estimable at this time.

Rangeland Pipeline Release. On June 7, 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. Ongoing monitoring will continue into 2013, and a long-term monitoring plan, if required, will be developed and implemented in accordance with regulatory requirements. Through March 31, 2013, we spent approximately $45 million, before insurance recoveries, in connection with site clean-up, reclamation and remediation activities, and as of March 31, 2013, we did not have any material outstanding liabilities or insurance receivables relating to this release. This release is currently under investigation by the ERCB. To date, no charges have been issued, and no fines or penalties have been assessed, against PMC with respect to this release; however, it is possible that charges and fines may be issued and/or assessed against PMC in the future.

Bay Springs Pipeline Release. On February 5, 2013, we experienced a crude oil release on a portion of one of our pipelines near Bay Springs, Mississippi. Although the volume of oil released has not been finally determined, we estimate that approximately 125 barrels were released. 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. We estimate that the aggregate clean-up and remediation costs associated with this release will not exceed $10 million.

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At March 31, 2013, our estimated undiscounted reserve for environmental liabilities totaled approximately $101 million, of which approximately $16 million was classified as short-term and approximately $85 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 March 31, 2013 and December 31, 2012, we had recorded receivables totaling approximately $16 million and $42 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements, which are predominantly reflected in Trade accounts receivable and other receivables, net on our condensed consolidated balance sheets.

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

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):

	Transportation		Facilities		Supply and Logistics		Total	
Three Months Ended March 31, 2013								
Revenues:								
External Customers	$	173	$	223	$	10,224	$	10,620
Intersegment (1)		195		131		1		327
Total revenues of reportable segments	$	368	$	354	$	10,225	$	10,947
Equity earnings in unconsolidated entities	$	11	$		$		$	11
Segment profit (2) (3)	$	164	$	150	$	434	$	748
Maintenance capital	$	32	$	7	$	5	$	44
Three Months Ended March 31, 2012								
Revenues:								
External Customers	$	150	$	191	$	8,877	$	9,218
Intersegment (1)		167		45				212
Total revenues of reportable segments	$	317	$	236	$	8,877	$	9,430
Equity earnings in unconsolidated entities	$	7	$		$		$	7
Segment profit (2) (3)	$	162	$	90	$	128	$	380
Maintenance capital	$	24	$	7	$	4	$	35

(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 $5 million and $2 million for the three months ended March 31, 2013 and 2012, respectively.

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

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	For the Three Months Ended March 31, 2013	2012
Segment profit	$ 748	$ 380
Depreciation and amortization	(82)	(60)
Interest expense	(77)	(65)
Other income, net		2
Income tax expense	(53)	(20)
Net income	536	237
Net income attributable to noncontrolling interests	(8)	(7)
Net income attributable to Plains	$ 528	$ 230

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 March 31, 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. During the three months ended March 31, 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 March 31, 2013	2012
Revenues	$ 269	$ 455
Purchases and related costs	$ 161	$ 148

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

	March 31, 2013	December 31, 2012
Trade accounts receivable and other receivables	$ 93	$ 231
Accounts payable	$ 164	$ 129

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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 three months of 2013, our net income attributable to Plains was approximately $528 million, or $1.27 per diluted limited partner unit, as compared to net income attributable to Plains of approximately $230 million, or $0.51 per diluted limited partner unit, recognized during the first three months of 2012. Major items impacting the favorable performance between periods include significantly stronger unit margins in our Supply and Logistics segment, contributions from the BP NGL and USD Rail Terminal Acquisitions, which were completed in April 2012 and December 2012, respectively, and a favorable period-over-period impact from the mark-to-market of derivative instruments.

The stronger unit margins in the Supply and Logistics segment, including the benefit from favorable location and quality differentials, are associated with the increased production from the development of North American crude oil and liquids-rich resource plays. As the midstream infrastructure in these producing regions continues to be developed, we believe a normalization of margins will occur as the logistics challenges are addressed. Supply and Logistics margins also benefitted from increased NGL sales margins due to improved market conditions, as well as additional volumes related to the BP NGL Acquisition noted above.

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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):

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012
Acquisition capital	$ 1	$ 21
Internal growth projects	358	236
Maintenance capital	44	35
Total	$ 403	$ 292

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	$180
Rainbow II Pipeline	130
Eagle Ford JV Project	95
Rail Terminal Projects (1)	90
White Cliffs Expansion	90
Gulf Coast Pipeline	90
Yorktown Terminal Projects	80
Eagle Ford Area Pipeline Projects	75
St. James Terminal Projects	55
Cactus Pipeline	50
PAA Natural Gas Storage (Multiple Projects)	42
Spraberry Area Pipeline Projects	40
Western Oklahoma Extension	40
Shafter Expansion	25
Cushing Terminal Projects	20
Other Projects (2)	298
	$1,400
Potential Adjustments for Timing/Scope Refinement (3)	- $50 + $150
Total Projected Expansion Capital Expenditures	$1,350 - $1,550

(1) Includes projects located at or near Tampa, CO, Bakersfield, CA, Carr, CO 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 projects from prior years.

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

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Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 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 March 31, 2013	Three Months Ended March 31, 2012	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %
Transportation segment profit	$ 164	$ 162	$ 2	1%
Facilities segment profit	150	90	60	67%
Supply and Logistics segment profit	434	128	306	239%
Total segment profit	748	380	368	97%
Depreciation and amortization	(82)	(60)	(22)	(37)%
Interest expense	(77)	(65)	(12)	(18)%
Other income, net		2	(2)	(100)%
Income tax expense	(53)	(20)	(33)	(165)%
Net income	536	237	299	126%
Less: Net income attributable to noncontrolling interests	(8)	(7)	(1)	(14)%
Net income attributable to Plains	$ 528	$ 230	$ 298	130%
Net income attributable to Plains:				
Earnings per basic limited partner unit	$ 1.28	$ 0.52	$ 0.76	146%
Earnings per diluted limited partner unit	$ 1.27	$ 0.51	$ 0.76	149%
Basic weighted average units outstanding	336	314	22	7%
Diluted weighted average units outstanding	339	316	23	7%

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 March 31, 2013	Three Months Ended March 31, 2012	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %
Net income	$ 536	$ 237	$ 299	126%
Add:				
Depreciation and amortization	82	60	22	37%
Income tax expense	53	20	33	165%
Interest expense	77	65	12	18%
EBITDA	$ 748	$ 382	$ 366	96%
Selected Items Impacting Comparability of EBITDA				
Gains/(losses) from derivative activities (1)	$ 24	$ (59)	$ 83	141%
Equity compensation expense (2)	(24)	(26)	2	8%
Net gain on foreign currency revaluation (3)	8		8	N/A
Significant acquisition-related expenses		(4)	4	100%
Other (4)	1	(1)	2	200%
Selected Items Impacting Comparability of EBITDA	$ 9	$ (90)	$ 99	110%
EBITDA	$ 748	$ 382	$ 366	96%
Selected Items Impacting Comparability of EBITDA	(9)	90	(99)	(110)%
Adjusted EBITDA	$ 739	$ 472	$ 267	57%
Adjusted EBITDA	739	472	267	57%
Interest expense	(77)	(65)	(12)	(18)%
Maintenance capital	(44)	(35)	(9)	(26)%
Current income tax expense	(46)	(17)	(29)	(171)%
Equity earnings in unconsolidated entities, net of distributions		(1)	1	100%
Distributions to noncontrolling interests (5)	(12)	(12)		%
Implied DCF	$ 560	$ 342	$ 218	64%

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods. See Note 11 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

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

(3) During the three months ended March 31, 2013, there were fluctuations in the value of the Canadian dollar to the U.S dollar, resulting in net gains 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) Includes other immaterial selected items impacting comparability.

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

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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, NGL and refined products on pipelines, gathering systems, trucks and barges. The Transportation segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and other transportation fees.

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

Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended March 31, 2013	2012	Favorable/ (Unfavorable) Variance $	%
Revenues (1)				
Tariff activities	$ 320	$ 278	$ 42	15%
Trucking	48	39	9	23%
Total transportation revenues	368	317	51	16%
Costs and Expenses (1)				
Trucking costs	(35)	(28)	(7)	(25)%
Field operating costs (excluding equity compensation expense)	(131)	(98)	(33)	(34)%
Equity compensation expense - operations (2)	(9)	(6)	(3)	(50)%
Segment general and administrative expenses (excluding equity compensation expense) (3)	(23)	(22)	(1)	(5)%
Equity compensation expense - general and administrative (2)	(17)	(8)	(9)	(113)%
Equity earnings in unconsolidated entities	11	7	4	57%
Segment profit	$ 164	$ 162	$ 2	1%
Maintenance capital	$ 32	$ 24	$ (8)	(33)%
Segment profit per barrel	$ 0.50	$ 0.56	$ (0.06)	(11)%

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Average Daily Volumes (in thousands of barrels per day) (4)	**Three Months Ended March 31, 2013**	**2012**	**Favorable/ (Unfavorable) Variance Volumes**	**%**
Tariff activities				
Crude Oil Pipelines				
All American	40	25	15	60%
Bakken Area Systems	123	137	(14)	(10)%
Basin / Mesa	725	642	83	13%
Capline	156	122	34	28%
Eagle Ford Area Systems	48	10	38	380%
Line 63 / Line 2000	118	118		%
Manito	47	68	(21)	(31)%
Mid-Continent Area Systems	268	221	47	21%
Permian Basin Area Systems	477	454	23	5%
Rainbow	122	142	(20)	(14)%
Rangeland	67	64	3	5%
Salt Lake City Area Systems	135	139	(4)	(3)%
White Cliffs	22	18	4	22%
Other	817	786	31	4%
NGL Pipelines				
Co-Ed	57		57	N/A
Other	207		207	N/A
Refined Products Pipelines	101	112	(11)	(10)%
Tariff activities total	3,530	3,058	472	15%
Trucking	111	108	3	3%
Transportation segment total	3,641	3,166	475	15%

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

(2) Equity 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. Selected Items Impacting Comparability included in the table under Results of Operations Non-GAAP Financial Measures excludes the portion of the equity compensation expense that will be settled in cash. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for additional discussion regarding our equity compensation plans.

(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 the three months ended March 31, 2013 compared to the three months ended March 31, 2012. The primary drivers of the significant variances in revenues and volumes between the comparative periods were:

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- BP NGL Acquisition The pipelines acquired through the BP NGL Acquisition on April 1, 2012 generated revenues of approximately $27 million and increased volumes by approximately 264,000 barrels per day for the three months ended March 31, 2013.

- North American Crude Oil Production and Related Expansion Projects Increased producer drilling activities, primarily in the Permian Basin, Oklahoma, Eagle Ford and Texas Panhandle producing regions, combined with our phased-in expansion projects, resulted in favorable volume and revenue variances for the three months ended March 31, 2013 over the comparative 2012 period, most notably on our Basin and Mesa pipelines and our Permian Basin, Mid-Continent and Eagle Ford Area Systems. We estimate that increased production combined with our phased-in expansion projects increased revenues by over $10 million for the first three months of 2013 over the comparable 2012 period.

- Rate Changes Revenues on our pipelines are impacted by various rate changes that may occur during the period. These rate changes primarily include the upward 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 from our FERC regulated pipelines during the first quarter of 2013 compared to the first quarter of 2012. Revenues were also favorably impacted by increasing tariff rates on certain of our non-FERC regulated pipelines. We estimate that the impact of these favorable rate changes increased revenues by over $15 million for the three months ended March 31, 2013 compared to the three months ended March 31, 2012.

- 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 $10 million for the three months ended March 31, 2013 compared to the three months ended March 31, 2012. This decrease was primarily due to a lower average realized price per barrel (including the impact of gains and losses from derivative-related activities), as compared to 2012.

Additional noteworthy volume and revenue variances for the three months ended March 31, 2013 compared to the three months ended March 31, 2012 include (i) increased volumes and revenues on our All American pipeline due to maintenance activities at the production facilities during the first quarter of 2012, (ii) increased volumes and revenues on Capline pipeline due to increased refinery demand during the first quarter of 2013, as well as unplanned refinery downtime during the first quarter of 2012 and (iii) decreased volumes on our Manito and Rainbow pipelines and our Bakken Area Systems primarily due to volumes diverted to rail.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the three months ended March 31, 2013 compared to the three months ended March 31, 2012 primarily due to approximately $12 million of environmental response and remediation expenses associated with pipeline releases, approximately $4 million of pipeline testing costs incurred as we considered bringing certain pipelines back into service, and higher insurance costs. Excluding the impacts of the environmental response and remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during these periods.

Equity Compensation Expense. Equity compensation expense increased for the three months ended March 31, 2013 compared to the three months ended March 31, 2012, primarily due to a more significant impact of the increase in unit price during the first quarter of 2013 compared to the impact of the increase during the first quarter of 2012, partially offset by a less significant impact during the first quarter of 2013 compared to the increase during the first quarter of 2012 of the change in assumption of probable distribution levels. 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 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 months ended March 31, 2013 compared to the three months ended March 31, 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 months ended March 31, 2013 compared to the three months ended March 31, 2012 was primarily due to increased earnings from our equity method investments as a result of increased demand for capacity on the White Cliffs pipeline and expansions and increased demand for services provided by Settoon Towing.

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Facilities Segment

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

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

Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended March 31, 2013	2012	Favorable/ (Unfavorable) Variance $	%
Revenues	$ 267	$ 165	$ 102	62%
Natural gas sales (2)	87	71	16	23%
Storage related costs (natural gas related)	(6)	(7)	1	14%
Natural gas sales costs (2)	(84)	(67)	(17)	(25)%
Field operating costs (excluding equity compensation expense)	(86)	(46)	(40)	(87)%
Equity compensation expense - operations (3)	(1)	(1)		%
Segment general and administrative expenses (excluding equity compensation expense) (4)	(17)	(14)	(3)	(21)%
Equity compensation expense - general and administrative (3)	(10)	(11)	1	9%
Segment profit	$ 150	$ 90	$ 60	67%
Maintenance capital	$ 7	$ 7	$	%
Segment profit per barrel	$ 0.42	$ 0.33	$ 0.09	27%

Volumes (5)(6)	Three Months Ended March 31, 2013	2012	Favorable/ (Unfavorable) Variance Volumes	%
Crude oil, refined products and NGL terminalling and storage (average monthly capacity in millions of barrels)	94	78	16	21%
Rail load / unload volumes (average volumes in thousands of barrels per day)	216		216	N/A
Natural gas storage (average monthly capacity in billions of cubic feet)	93	76	17	22%
NGL fractionation (average volumes in thousands of barrels per day)	100	11	89	809%
Facilities segment total (average monthly volumes in millions of barrels)	119	91	28	31%

(1) Revenues and expenses include intersegment amounts.

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

(3) Equity 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. Selected Items Impacting Comparability included in the table under Results of Operations Non-GAAP Financial Measures excludes the portion of the equity compensation expense that will be settled in cash. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for additional discussion regarding our equity compensation plans.

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

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

(6) Facilities total calculated as the sum of: (i) crude oil, refined products and NGL terminalling and storage capacity; (ii) rail load and unload volumes multiplied by the number of days in the period and divided by the number of months in the period; (iii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iv) NGL fractionation volumes multiplied by the number of days in the period and divided by the number of months in the period.

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

Operating Revenues and Volumes. As noted in the tables above, our Facilities segment revenues and volumes increased for the three months ended March 31, 2013 compared to the same period in 2012. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our ongoing acquisition and expansion activities as discussed below:

- BP NGL Acquisition The NGL storage facilities, fractionation plants and related assets acquired through the BP NGL Acquisition on April 1, 2012 contributed aggregate revenues of approximately $66 million for the three months ended March 31, 2013. These assets increased average monthly capacity of NGL storage by approximately 14 million barrels and increased average NGL fractionation throughput by approximately 87,000 barrels per day for the three months ended March 31, 2013.

- Rail Terminals The USD Rail Terminal Acquisition completed in December 2012 and internal growth projects completed throughout 2012 expanded our rail loading and unloading fee-based activities. Our rail load and unload activities contributed approximately $26 million to the increase in total revenues for the comparative periods and approximately 216,000 barrels per day of throughput volumes during the three months ended March 31, 2013.

Field Operating Costs. Field operating costs (excluding equity compensation expense) increased during the three months ended March 31, 2013 compared to the three months ended March 31, 2012 due to our growth through acquisitions, primarily the BP NGL and USD Rail Terminal acquisitions. Additionally, the BP NGL Acquisition assets and operations typically have a higher ratio of operating costs to revenue than our historic operations in this segment.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation expense) increased during the three months ended March 31, 2013 compared to the three months ended March 31, 2012 due to growth associated with the BP NGL Acquisition.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, as well as sales of NGL volumes purchased from suppliers. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our Supply and Logistics segment volumes (which consist of lease gathered crude oil purchase volumes, NGL sales volumes and waterborne cargos), (ii) demand for lease gathering services we provide producers and (iii) the overall volatility and strength or weakness of market conditions and the allocation of our assets among our various risk management strategies. In addition, the execution of our risk management strategies in conjunction with our assets can provide upside in certain markets. Although we believe that the combination of our lease gathered business and our risk management activities provides a balance that provides general stability in our margins, these margins are not fixed and may vary from period to period.

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

Operating Results (1) **(in millions, except per barrel amounts)**	**Three Months Ended March 31, 2013**	**2012**	**Favorable/ (Unfavorable) Variance $**	**%**
Revenues	$ 10,225	$ 8,877	$ 1,348	15%
Purchases and related costs (2)	(9,636)	(8,608)	(1,028)	(12)%
Field operating costs (excluding equity compensation expense)	(115)	(101)	(14)	(14)%
Equity compensation expense - operations (3)	(1)	(1)		%
Segment general and administrative expenses (excluding equity compensation expense) (4)	(26)	(27)	1	4%
Equity compensation expense - general and administrative (3)	(13)	(12)	(1)	(8)%
Segment profit	$ 434	$ 128	$ 306	239%
Maintenance capital	$ 5	$ 4	$ (1)	(25)%
Segment profit per barrel	$ 4.21	$ 1.51	$ 2.70	179%

Average Daily Volumes **(in thousands of barrels per day)**	**Three Months Ended March 31, 2013**	**2012**	**Favorable/ (Unfavorable) Variance Volumes**	**%**
Crude oil lease gathering purchases	857	798	59	7%
NGL sales	284	134	150	112%
Waterborne cargos	4		4	N/A
Supply and Logistics segment total	1,145	932	213	23%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil and NGL inventory) of approximately $5 million and $2 million for the three months ended March 31, 2013 and 2012, respectively.

(3) Equity compensation expense presented in the table above includes expenses associated with awards that will or may be settled in units and that will or may be settled in cash. Selected Items Impacting Comparability included in the table under Results of Operations Non-GAAP Financial Measures excludes the portion of the equity compensation expense that will be settled in cash. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2012 Annual Report on Form 10-K for additional discussion regarding our equity compensation plans.

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

The NYMEX benchmark price of crude oil ranged from approximately $89 to $98 per barrel and $95 to $111 per barrel during the three months ended March 31, 2013 and 2012, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for the three months ended March 31, 2013 and 2012 primarily from increased volumes in 2013.

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Generally, we expect a base level of earnings from our Supply and Logistics segment from the assets employed by this segment. This base level may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. Our Supply and Logistics segment operating results are further impacted by foreign currency translations adjustments as certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates. Also, our NGL marketing operations are sensitive to weather-related demand, particularly during the approximate five-month peak heating season of November through March, and temperature differences from period to period may have a significant effect on NGL demand and thus our financial performance.

The following is a discussion of items impacting Supply and Logistics segment profit and segment profit per barrel for the periods indicated:

Operating Revenues and Volumes. Our Supply and Logistics segment revenues, net of purchases and related costs and excluding gains and losses from derivative activities (see the table below), and volumes increased for the three months ended March 31, 2013 compared to the three months ended March 31, 2012. Generally, the increasing production of oil and liquids-rich gas in North America has created supply and demand imbalances that have increased the volatility of historical differentials for various grades of crude oil and has also impacted the historical pricing relationship between NGL and crude oil. These market conditions have generally been favorable to our supply and logistics activities. The following summarizes the more significant items in the comparative periods:

- increased margins related to opportunities created in certain producing regions where crude oil production volumes exceed existing pipeline takeaway capacity and where there are associated logistics challenges. We have utilized various methods of transportation to capture enhanced margins in these regions. We believe the fundamentals of our business remain strong; however, as the midstream infrastructure in these producing regions continues to be developed, we believe a normalization of margins will occur as the logistics challenges are addressed. (See Items 1 and 2 Business and Properties Description of Segments and Associated Assets *Supply and Logistics Segment* Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model included in Part I of our 2012 Annual Report on Form 10-K for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

- opportunities from more favorable crude oil quality differentials experienced in certain regions; and

- higher volumes due to continued increases in production related to the active development of crude oil and liquids-rich resource plays, primarily a result of increased drilling activities in the Permian Basin, Eagle Ford, Oklahoma and Texas Panhandle producing regions.

In addition, NGL sales volumes and margins increased for the three months ended March 31, 2013 compared to 2012 primarily due to higher demand related to increases in (i) heating requirements during an extended winter season, (ii) export activity that reduced overall product availability in the market and (iii) petrochemical demand. NGL sales volumes and margins were also favorably impacted by our BP NGL Acquisition, which was completed on April 1, 2012.

Impact from derivative activities. The mark-to-market valuation of our derivative activities also favorable impacted our results for the three months ended March 31, 2013 compared to the three months ended March 31,2012, as shown in the table below (in millions):

	Three Months Ended March 31, 2013	Three Months Ended March 31, 2012	Variance
Gains/(losses) from derivative activities (1)	$ 24	$ (61)	$ 85

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods. See Note 11 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and risk management activities.

Field Operating Costs. Field operating costs (excluding equity compensation expense) increased in the three months ended March 31, 2013 compared to the three months ended March 31, 2012 primarily related to increased lease gathered volumes, particularly in West Texas, Oklahoma and the Rockies.

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Other Income and Expenses

Depreciation and Amortization

Depreciation and amortization expense was approximately $82 million for the three months ended March 31, 2013 compared to approximately $60 million for the three months ended March 31, 2012. The increase in the 2013 period over the comparative 2012 period was primarily the result of an increased amount of assets resulting from acquisition activities, including amortization of certain intangible assets associated with those acquisitions, as well as various internal growth projects in both years.

Interest Expense

Interest expense increased by approximately $12 million for the three months ended March 31, 2013, compared to the three months ended March 31, 2012. This increase was primarily related to the collective issuances of approximately $1.25 billion of senior notes in March 2012, which were used to fund the BP NGL Acquisition, and approximately $750 million of senior notes in December 2012, which were used primarily to fund our growth through acquisitions and our ongoing capital program.

Income Tax Expense

Income tax expense for the three months ended March 31, 2013 compared to the three months ended March 31, 2012 increased by approximately $33 million, primarily as a result of the BP NGL Acquisition, as well as the strength of our existing operations, which increased the proportion of earnings subject to Canadian federal and provincial taxes. Canadian withholding taxes also increased on interest and dividends from our Canadian entities to other affiliates. These Canadian withholding taxes are due as payments occur.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our cash flow from operating activities, (ii) borrowings under our credit facilities and (iii) funds received from sales of equity and debt securities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil and other products and other expenses and interest payments on our outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through our primary sources of liquidity. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions and refinancing our long-term debt, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. As of March 31, 2013, we had a working capital surplus of approximately $118 million and approximately $2.77 billion of liquidity available to meet our other ongoing operational, investing and finance needs as noted below (in millions):

		As of March 31, 2013
Availability under PAA senior unsecured revolving credit facility	$	1,556
Availability under PAA senior secured hedged inventory facility		1,055
Availability under PNG senior unsecured revolving credit facility		131
Cash and cash equivalents		24
Total	$	2,766

We believe that we will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Risk Factors in Item 1A of our 2012 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of our credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

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Cash Flows from Operating Activities

For a comprehensive discussion of the primary drivers of our cash flow from operating activities, including the impact of varying market conditions and the timing of settlement of our derivative activities, see Liquidity and Capital Resources Cash Flow from Operations under Item 7 of our 2012 Annual Report on Form 10-K.

Net cash provided by operating activities for the first three months of 2013 was approximately $979 million. The cash provided by operating activities reflects cash generated by our recurring operations, and can also be significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first quarter of 2013, we decreased the amount of our inventory. The decrease in inventory was primarily due to the sale of NGL inventory related to higher product demand caused by increases in (i) heating requirements during an extended winter season, (ii) export activity that reduced overall product availability in the market and (iii) petrochemical demand. The net proceeds received from liquidation of such inventory during the quarter were used to repay borrowings under our credit facilities and favorably impacted our cash flow from operating activities.

Net cash provided by operating activities for the first three months of 2012 was approximately $317 million. During the first quarter of 2012, we decreased our NGL inventory resulting from end users demand for heating requirements during the winter heating season. The cash flow generated from liquidating our NGL inventory for the first three months of 2012 was partially offset by increasing our crude oil inventory levels primarily due to storing barrels in the contango market.

Equity and Debt Financing Activities

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

Registration Statements

We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). All issuances of equity securities associated with our continuous offering program, as discussed further below, have been issued pursuant to the Traditional Shelf. At March 31, 2013, we had approximately $1.8 billion of unsold securities available under the Traditional Shelf.

We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs.

PNG has filed with the SEC a universal shelf registration statement (PNG Shelf) that, subject to effectiveness at the time of use, allows PNG to issue up to an aggregate of $1.0 billion of debt or equity securities. All issuances of equity securities associated with PNG s continuous offering program, as discussed further below, have been issued pursuant to the PNG Shelf. At March 31, 2013, PNG had approximately $999 million of unsold securities available under the PNG Shelf.

PAA Continuous Offering Program

During the three months ended March 31, 2013, we issued an aggregate of approximately 2.4 million common units under our continuous offering program, generating net proceeds of approximately $131 million, including our general partner s proportionate capital contribution. The net proceeds from sales were used for general partnership purposes.

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. Sales of such common units will be made by means of ordinary brokers transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by the sales agent and PNG. Under the terms of the agreement, PNG has the option to sell common units to the sales agent as principal for its own account at a price to be agreed upon at the time of the sale. For any such sales, PNG will enter into a separate terms agreement with the sales agent.

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During the first quarter of 2013, PNG issued an aggregate of approximately 57,000 common units under this agreement, generating net proceeds of approximately $1.2 million, including our proportionate capital contribution for our general partner interest.

Credit Agreements

General. During the three months ended March 31, 2013, we had net repayments on our credit agreements, which include our revolving credit facilities and our hedged inventory facility, in the aggregate of approximately $380 million. These net repayments resulted primarily from cash flows from operating activities, such as sales of NGL inventory that was liquidated during the period as well as our debt and equity activities.

During the three months ended March 31, 2012, we had net borrowings on our credit agreements in the aggregate of approximately $104 million. These net borrowings resulted primarily when we increased our crude oil inventory levels related to storing barrels in the contango market, which more than offset the normal seasonal decrease in NGL inventory. For further discussion related to our credit facilities and long-term debt, see Cash Flows from Operating Activities above and Liquidity and Capital Resources Credit Facilities and Indentures under Item 7 of our 2012 Annual Report on Form 10-K.

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

We also use cash for our acquisition activities, internal growth projects and distributions paid to our unitholders, general partner and noncontrolling interests. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by the operating and financing activities discussed above. See Internal Growth Projects above and Acquisitions and Internal Growth Projects under Item 7 of our 2012 Annual Report on Form 10-K for further discussion of such capital expenditures.

Acquisitions. The price of acquisitions includes cash paid, assumed liabilities and net working capital items. Because of the non-cash items included in the total price of acquisitions and the timing of certain cash payments, the net cash paid may differ significantly from the total price of acquisitions completed during the year.

Distributions to our unitholders and general partner. We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter less reserves established in the discretion of our general partner for future requirements. On May 15, 2013, we will pay a quarterly distribution of $0.5750 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 10.0%. See Note 9 to our condensed consolidated financial statements for details of distributions paid. Also, see Item 5. Market for Registrant s Common Units, Related Unitholder Matters and Issuer Purchases of Equity Securities Cash Distribution Policy included in our 2012 Annual Report on Form 10-K for additional discussion on distributions.

Distributions to noncontrolling interests. We paid approximately $12 million for distributions to noncontrolling interests during each of the three months ended March 31, 2013 and 2012. These amounts represent distributions paid on interests in PNG and SLC that are not owned by us.

We believe that we have sufficient liquid assets, cash flow from operations and borrowing capacity under our credit agreements to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures. We are, however, subject to business and operational risks that could adversely affect our cash flow. A material decrease in our cash flows would likely produce an adverse effect on our borrowing capacity.

Contingencies

For a discussion of contingencies that may impact us, see Note 12 to our condensed consolidated financial statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and NGL from third parties under contracts, the majority of which range in term from thirty-day evergreen to five years. We establish a margin for these purchases by entering into various types of physical and financial sale and exchange transactions through which we seek to maintain a position that is substantially balanced between purchases on the one hand and sales and future delivery obligations on the other. In addition, we enter into similar contractual obligations in conjunction with our natural gas operations. The table below includes purchase obligations related to these activities. Where applicable, the amounts presented represent the net obligations associated with buy/sell contracts and those subject to a net settlement arrangement with the counterparty. We do not expect to use a significant amount of internal capital to meet these obligations, as the obligations will be funded by corresponding sales to entities that we deem creditworthy or who have provided credit support we consider adequate.

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The following table includes our best estimate of the amount and timing of these payments as well as others due under the specified contractual obligations as of March 31, 2013 (in millions):

	2013	2014	2015	2016	2017	2018 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 509	$ 332	$ 873	$ 792	$ 666	$ 7,359	$ 10,531
Leases (2)	103	129	114	101	74	389	910
Other obligations (3)	304	91	56	31	25	137	644
Subtotal	916	552	1,043	924	765	7,885	12,085
Crude oil, natural gas, NGL and other purchases (4)	7,051	2,900	1,878	1,798	1,324	2,794	17,745
Total	$ 7,967	$ 3,452	$ 2,921	$ 2,722	$ 2,089	$ 10,679	$ 29,830

(1) Includes debt service payments, interest payments due on our senior notes, interest payments and the commitment fee on the PNG credit agreement and the commitment fee on our PAA credit facilities. Although there is an outstanding balance on our PAA credit facilities at March 31, 2013, we historically repay and borrow at varying amounts. As such, we have included only the maximum commitment fee (as if no amounts were outstanding on the facility) in the amounts above.

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

(3) Includes (i) other long-term liabilities, (ii) storage and transportation agreements and (iii) commitments related to our capital expansion projects, including projected contributions for our share of the capital spending of our equity-method investments. Excludes a non-current liability of approximately $22 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) Amounts are primarily based on estimated volumes and market prices based on average activity during March 2013. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

Letters of Credit. In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. Our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At March 31, 2013 and December 31, 2012, we had outstanding letters of credit of approximately $56 million and $24 million, respectively.

Off-Balance Sheet Arrangements

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

Recent Accounting Pronouncements

See Note 2 to our condensed consolidated financial statements.

Critical Accounting Policies and Estimates

For additional discussion regarding our critical accounting policies and estimates, see Critical Accounting Policies and Estimates under Item 7 of our 2012 Annual Report on Form 10-K.

Forward-Looking Statements

All statements included in this report, other than statements of historical fact, are forward-looking statements, including but not limited to statements incorporating the words anticipate, believe, estimate, expect, plan, intend and forecast, as well as similar expressions and st regarding our business strategy, plans and objectives for future operations. The absence of such words, expressions or statements, however, does not mean that the statements are not forward-looking. Any such forward-looking statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain

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factors could cause actual results or outcomes to differ materially from the results or outcomes anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- failure to implement or capitalize, or delays in implementing or capitalizing, on planned internal growth projects;
- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- the availability of, and our ability to consummate, acquisition or combination opportunities;
- the successful integration and future performance of acquired assets or businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- the occurrence of a natural disaster, catastrophe, terrorist attack or other event, including attacks on our electronic and computer systems;
- tightened capital markets or other factors that increase our cost of capital or limit our access to capital;
- maintenance of our credit rating and ability to receive open credit from our suppliers and trade counterparties;
- continued creditworthiness of, and performance by, our counterparties, including financial institutions and trading companies with which we do business;
- the effectiveness of our risk management activities;
- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- declines in the volume of crude oil, refined product and NGL shipped, processed, purchased, stored, fractionated and/or gathered at or through the use of our facilities, whether due to declines in production from existing oil and gas reserves, failure to or slowdown in the development of additional oil and gas reserves or other factors;

- shortages or cost increases of supplies, materials or labor;

- fluctuations in refinery capacity in areas supplied by our mainlines and other factors affecting demand for various grades of crude oil, refined products and natural gas and resulting changes in pricing conditions or transportation throughput requirements;

- our ability to obtain debt or equity financing on satisfactory terms to fund additional acquisitions, expansion projects, working capital requirements and the repayment or refinancing of indebtedness;

- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements, and related interpretations;

- non-utilization of our assets and facilities;

- the effects of competition;

- interruptions in service on third-party pipelines;

- increased costs or lack of availability of insurance;

- fluctuations in the debt and equity markets, including the price of our units at the time of vesting under our long-term incentive plans;

- the currency exchange rate of the Canadian dollar;

- weather interference with business operations or project construction;

- risks related to the development and operation of our facilities;

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- factors affecting demand for natural gas and natural gas storage services and rates;

- general economic, market or business conditions and the amplification of other risks caused by volatile financial markets, capital constraints and pervasive liquidity concerns; and

- other factors and uncertainties inherent in the transportation, storage, terminalling and marketing of crude oil and refined products, as well as in the storage of natural gas and the processing, transportation, fractionation, storage and marketing of natural gas liquids.

Other factors described herein, as well as factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risk Factors discussed in Item 1A of our 2012 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

We use derivative instruments to hedge commodity price risk associated with the following commodities:

- *Crude oil and refined products*

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

- *Natural gas*

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

- *NGL*

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

See Note 11 to our condensed consolidated financial statements for further discussion regarding our hedging strategies and objectives.

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

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The fair value of our commodity derivatives and the change in fair value as of March 31, 2013 that would be expected from a 10% price increase or decrease is shown in the table below (in millions):

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil and related products	$ 9	$ (25)	$ 26
Natural gas	(17)	$ (4)	$ 4
NGL and other	52	$ 13	$ (13)
Total fair value	$ 44		

The fair values presented in the table above reflect the sensitivity of the derivative instruments only and do not include the effect of the underlying hedged commodity. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term commodity prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Interest Rate Risk

Our use of variable rate debt and any forecasted issuances of fixed rate debt expose us to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus are not subject to interest rate risk. The majority of our variable rate debt at March 31, 2013, approximately $650 million (which excludes $100 million of variable rate debt when giving consideration to our interest rate derivatives that swap floating rate debt for fixed), is subject to interest rate re-sets, which range from one week to three months. The average interest rate of approximately 1.8% is based upon rates in effect during the three months ended March 31, 2013 without giving consideration to our interest rate swaps. The fair value of our interest rate derivatives is an unrealized loss of approximately $21 million as of March 31, 2013. A 10% increase in the forward LIBOR curve as of March 31, 2013 would result in an increase of approximately $25 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of March 31, 2013 would result in a decrease of approximately $25 million to the fair value of our interest rate derivatives. See Note 11 to our condensed consolidated financial statements for a discussion of our interest rate risk hedging activities.

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written disclosure controls and procedures, which we refer to as our DCP. Our DCP is designed to ensure that information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is (i) recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow for timely decisions regarding required disclosure.

Applicable SEC rules require an evaluation of the effectiveness of the design and operation of our DCP. Management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our DCP as of the end of the period covered by this report, and has found our DCP to be effective in providing reasonable assurance of the timely recording, processing, summarization and reporting of information, and in accumulation and communication of information to management to allow for timely decisions with regard to required disclosure.

Changes in Internal Control over Financial Reporting

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

Certifications

The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to Exchange Act rules 13a-14(a) and 15d-14(a) are filed with this report as Exhibits 31.1 and 31.2. The certifications of our Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. 1350 are furnished with this report as Exhibits 32.1 and 32.2.

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PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption Litigation in Note 12 to our condensed consolidated financial statements, and is incorporated herein by reference thereto.

Item 1A. RISK FACTORS

For a discussion regarding our risk factors, see Item 1A of our 2012 Annual Report on Form 10-K. Those risks and uncertainties are not the only ones facing us and there may be additional matters of which we are unaware or that we currently consider immaterial. All of those risks and uncertainties could adversely affect our business, financial condition and/or results of operations.

Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None.

Item 4. MINE SAFETY DISCLOSURES

None.

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

The exhibits listed on the accompanying Exhibit Index are filed or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By:	PAA GP LLC, its general partner
By:	PLAINS AAP, L.P., its sole member
By:	PLAINS ALL AMERICAN GP LLC, its general partner

Date: May 8, 2013

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong, *Chairman of the Board, Chief Executive Officer and Director*
(Principal Executive Officer)

Date: May 8, 2013

By: /s/ AL SWANSON
Al Swanson, *Executive Vice President and Chief Financial Officer*
(Principal Financial Officer)

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EXHIBIT INDEX

3.1	Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of May 17, 2012 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 23, 2012).
3.2	Amendment No. 1 dated October 1, 2012 to the Fourth Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed October 2, 2012).
3.3	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.4	Amendment No. 1 dated December 31, 2010 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.9 to the Annual Report on Form 10-K for the year ended December 31, 2010).
3.5	Amendment No. 2 dated January 1, 2011 to the Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2010).
3.6	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.7	Fifth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated December 23, 2010 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed December 30, 2010).
3.8	Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).
3.9	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.10	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.11	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.3	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia

Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).

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4.4	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.5	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.6	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.7	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.8	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.9	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.10	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.11	Eighteenth Supplemental Indenture (3.95% Senior Notes due 2015) dated July 14, 2010 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 13, 2010).
4.12	Nineteenth Supplemental Indenture (5.00% Senior Notes due 2021) dated January 14, 2011 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed January 11, 2011).
4.13	Twentieth Supplemental Indenture (3.65% Senior Notes due 2022) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed March 26, 2012).
4.14	Twenty-First Supplemental Indenture (5.15% Senior Notes due 2042) dated March 22, 2012 among Plains All American Pipeline, L.P., PAA Finance Corp. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed March 26, 2012).
4.15	Twenty-Second Supplemental Indenture (2.85% Senior Notes due 2023) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp., and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed December 12, 2012).
4.16	

Twenty-Third Supplemental Indenture (4.30% Senior Notes due 2043) dated December 10, 2012, by and among Plains All American Pipeline, L.P., PAA Finance Corp., and U.S. Bank National Association, as

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	trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed December 12, 2012).
10. 1	Form of PAA LTIP Grant Letter for Officers (February 2013).
12.1	Computation of Ratio of Earnings to Fixed Charges
31.1	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document

Filed herewith.

Furnished herewith.