PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
May 08, 2012
Table of Contents

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, 2012

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	**76-0582150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
333 Clay Street, Suite 1600, Houston, Texas	**77002**
(Address of principal executive offices)	(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 May 3, 2012, there were 161,318,749 Common Units outstanding.

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

TABLE OF CONTENTS

Table of Contents

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, 2012	December 31, 2011
	(unaudited)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 14	$ 26
Trade accounts receivable and other receivables, net	2,902	3,190
Inventory	1,079	978
Other current assets	171	157
Total current assets	4,166	4,351
PROPERTY AND EQUIPMENT	9,312	9,029
Accumulated depreciation	(1,337)	(1,289)
	7,975	7,740
OTHER ASSETS		
Goodwill	1,879	1,854
Restricted cash (Note 4)	1,632	
Linefill and base gas	577	564
Long-term inventory	146	135
Investments in unconsolidated entities	192	191
Other, net	514	546
Total assets	$ 17,081	$ 15,381
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,489	$ 3,599
Short-term debt	757	679
Other current liabilities	196	233
Total current liabilities	4,442	4,511
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $15 and $13, respectively	5,510	4,262
Long-term debt under credit facilities and other	284	258
Other long-term liabilities and deferred credits	332	376
Total long-term liabilities	6,126	4,896

COMMITMENTS AND CONTINGENCIES (NOTE 12)				
PARTNERS CAPITAL				
Common unitholders (161,318,749 and 155,376,937 units outstanding, respectively)		5,779		5,249
General partner		218		201
Total partners capital excluding noncontrolling interests		5,997		5,450
Noncontrolling interests		516		524
Total partners capital		6,513		5,974
Total liabilities and partners capital	$	17,081	$	15,381

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
	(unaudited)			
REVENUES				
Supply and Logistics segment revenues	$	8,877	$	7,435
Transportation segment revenues		150		141
Facilities segment revenues		191		118
Total revenues		9,218		7,694
COSTS AND EXPENSES				
Purchases and related costs		8,502		7,079
Field operating costs		249		197
General and administrative expenses		94		70
Depreciation and amortization		60		63
Total costs and expenses		8,905		7,409
OPERATING INCOME		313		285
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities		7		
Interest expense (net of capitalized interest of $9 and $5, respectively)		(65)		(65)
Other income/(expense), net		2		(22)
INCOME BEFORE TAX		257		198
Current income tax expense		(17)		(11)
Deferred income tax expense		(3)		(2)
NET INCOME		237		185
Net income attributable to noncontrolling interests		(7)		(3)
NET INCOME ATTRIBUTABLE TO PLAINS	$	230	$	182
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$	162	$	129
GENERAL PARTNER	$	68	$	53
BASIC NET INCOME PER LIMITED PARTNER UNIT	$	1.03	$	0.90
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$	1.02	$	0.90
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING		157		143
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING		158		144

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(unaudited)	
Net income	$ 237	$ 185
Other comprehensive income/(loss)	59	(29)
Comprehensive income	296	156
Less: Comprehensive income attributable to noncontrolling interests	(3)	(3)
Comprehensive income attributable to Plains	$ 293	$ 153

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, December 31, 2011	$ (102)	$ 156	$ 54
Reclassification adjustments	(52)		(52)
Deferred gain on cash flow hedges, net of tax	76		76
Currency translation adjustment		35	35
Total period activity	24	35	59
Balance, March 31, 2012	$ (78)	$ 191	$ 113

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 237	$ 185
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	60	63
Equity compensation expense	39	20
Gain on sales of linefill and base gas	(12)	(13)
Net cash received/(paid) for terminated interest rate or foreign currency hedging instruments	(23)	12
Other	(4)	3
Changes in assets and liabilities, net of acquisitions	20	384
Net cash provided by operating activities	317	654
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(21)	(756)
Change in restricted cash	(1,632)	18
Additions to property and equipment	(263)	(121)
Proceeds from sales of assets	13	
Net cash received for sales and purchases of linefill and base gas	13	19
Other investing activities		(2)
Net cash used in investing activities	(1,890)	(842)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net borrowings/(repayments) on PAA s revolving credit facility	184	(654)
Net repayments on PAA s hedged inventory facility	(75)	(200)
Net repayments on PNG s credit agreements	(5)	(52)
Proceeds from the issuance of senior notes	1,247	597
Repayments of senior notes		(200)
Net proceeds from the issuance of common units (Note 9)	455	503
Cash received for sale of noncontrolling interest in a subsidiary		370
Distributions paid to common unitholders (Note 9)	(159)	(135)
Distributions paid to general partner (Note 9)	(66)	(49)
Distributions to noncontrolling interests	(12)	(5)
Other financing activities	(9)	(4)
Net cash provided by financing activities	1,560	171
Effect of translation adjustment on cash	1	
Net decrease in cash and cash equivalents	(12)	(17)
Cash and cash equivalents, beginning of period	26	36
Cash and cash equivalents, end of period	$ 14	$ 19
Cash paid for interest, net of amounts capitalized	$ 78	$ 71
Cash paid for income taxes, net of amounts refunded	$ 28	$

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units		General	Partners Capital Excluding Noncontrolling	Noncontrolling	Partners
	Units	Amount	Partner	Interests	Interests	Capital
			(unaudited)			
Balance, December 31, 2011	155	$ 5,249	$ 201	$ 5,450	$ 524	$ 5,974
Net income		162	68	230	7	237
Distributions		(159)	(66)	(225)	(12)	(237)
Issuance of common units	6	446	9	455		455
Issuance of common units under LTIP		16		16		16
Equity compensation expense		3	5	8	1	9
Other comprehensive income/(loss)		62	1	63	(4)	59
Balance, March 31, 2012	161	$ 5,779	$ 218	$ 5,997	$ 516	$ 6,513

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

Table of Contents

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Basis of Presentation

Organization

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 liquid 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 three operating segments.

As used in this Form 10-Q and unless the context indicates otherwise, the terms Partnership, Plains, PAA, we, us, our, ours and simila refer to Plains All American Pipeline, L.P. and its subsidiaries. Also, 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.

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
MQD	=	Minimum quarterly distribution
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

Table of Contents

Basis of Consolidation and Presentation

The accompanying unaudited condensed consolidated interim financial statements and notes thereto should be read in conjunction with our 2011 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. As discussed further below, 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, 2011 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, 2012 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.

Revision of Prior Period Financial Statements

Limited Partner and General Partner Income Allocation

During 2011, we identified an error in the manner in which we allocate net income to our limited partners and general partner. Previously, we calculated net income available to limited partners based on the distribution paid during the period by first allocating the incentive distribution paid during the period to the general partner and then allocating the remaining net income based on ownership interests (98% limited partner and 2% general partner). We have revised this allocation to utilize the distributions pertaining to the period, which are paid in the subsequent period. This revision does not impact net income, net income attributable to Plains, net income per limited partner unit, total partners capital or cash flows. We have determined that the impact of this error is not material to the previously issued financial statements. We have presented these changes retrospectively in the condensed consolidated statement of operations, which resulted in the following changes (in millions):

Three Months Ended March 31, 2011	As Previously Reported	As Revised
Net Income Attributable to Plains:		
Limited Partners	$ 133	$ 129
General Partner	49	53
	$ 182	$ 182

Note 2 Recent Accounting Pronouncements

Other than as discussed below and in our 2011 Annual Report on Form 10-K, no new accounting pronouncements have become effective during the three months ended March 31, 2012 that are of significance or potential significance to us.

In September 2011, the FASB issued guidance with the purpose of simplifying the goodwill impairment test by permitting entities to perform a qualitative assessment to determine whether further impairment testing is necessary. If qualitative factors indicate that it is more likely than not that the fair value of a reporting unit is greater than its carrying amount, an entity need not perform the two-step goodwill impairment test. This guidance became effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. We adopted this guidance on January 1, 2012. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

In June 2011, the FASB issued guidance regarding the presentation of other comprehensive income, which was later amended in December 2011, with the purpose of increasing the prominence of other comprehensive income in financial statements. This guidance, as amended, requires entities to present comprehensive income in either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. This guidance became effective for interim and annual periods beginning after December 15, 2011. We adopted the guidance, as amended, on January 1, 2012. Since this guidance only impacts the presentation of comprehensive income and does not change the composition or calculation of such financial information, adoption did not have a material impact on our financial position, results of operations or cash flows.

In May 2011, the FASB issued guidance to amend certain fair value measurement and disclosure requirements in an effort to improve consistency with international reporting standards. The amendments generally clarify that the concepts of highest and best use and valuation premise in fair value measurement are relevant only when measuring the fair value of non-financial assets and are not relevant when measuring the fair value of financial assets or of liabilities. In addition, the guidance expanded disclosure requirements associated with (i) unobservable inputs for Level 3 fair value measurements and (ii) items that are not measured at fair value in the financial statements, but for which fair value is required to be disclosed. This guidance became effective prospectively for

Table of Contents

interim and annual reporting periods beginning after December 15, 2011. We adopted this guidance on January 1, 2012. Other than requiring additional disclosure, which is included in Note 7, our adoption did not have a material impact on our financial position, results of operations or cash flows.

Note 3 Accounts Receivable

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, 2012 and December 31, 2011, 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 $5 million at both March 31, 2012 and December 31, 2011. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

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, 2012 and December 31, 2011, we had received approximately $177 million and $186 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements (contractual agreements that allow us and the counterparty to offset receivables and payables between the two) that cover a significant portion of our transactions and also serve to mitigate credit risk.

Note 4 Acquisitions

The following acquisitions were accounted for using the purchase method of accounting and the purchase price of each acquisition was determined in accordance with such method.

Acquisition Closed Subsequent to March 31, 2012

BP NGL Acquisition. On April 1, 2012, we acquired all of the outstanding shares of BP Canada Energy Company, a wholly owned subsidiary of BP Corporation North America Inc. (BP North America). Total consideration for the acquisition, which was based on an October 1, 2011 effective date, was approximately $1.67 billion, subject to working capital and other adjustments. A cash deposit of $50 million was paid upon signing, and the balance plus 2% interest from October 1, 2011 was paid in cash upon closing. As of March 31, 2012, we had approximately $1.63 billion in restricted cash held by an escrow agent in contemplation of closing this acquisition.

Upon completion of this acquisition, we became the indirect owner of all of BP North America s Canadian-based NGL business and certain of BP North America s NGL assets located in the upper-Midwest United States (collectively the BP NGL Assets). The BP NGL Assets acquired include varying ownership interests and contractual rights relating to approximately 2,600 miles of NGL pipelines; approximately 20 million barrels of NGL storage capacity; seven fractionation plants with an aggregate net capacity of approximately 232,000 barrels per day; four straddle plants and two field gas processing plants with an aggregate net capacity of approximately six Bcf per day; and long-term and seasonal NGL inventories of approximately 8 million barrels upon closing. Certain of these pipelines and storage assets are currently inactive. The acquired business also includes various third-party supply contracts at other field gas processing plants and a supply contract relating to a third-party owned straddle plant with throughput capacity of 2.5 Bcf per day, shipping arrangements on third-party NGL pipelines and long-term leases on 720 rail cars used to move product among various locations. We have also entered into an Integrated Supply and Trading Agreement, pursuant to which an affiliate of BP North America will, for a period of two years following the closing of the acquisition, continue to provide sourcing services for gas supply to feed certain of the straddle plants acquired as a result of the acquisition.

Other Acquisitions

During the three months ended March 31, 2012 we completed two acquisitions for an aggregate consideration of approximately $21 million. The assets acquired primarily included trailers that are utilized in our transportation segment, and terminal facilities included in our facilities segment. We recognized goodwill of approximately $10 million related to these acquisitions.

Table of Contents

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

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

	March 31, 2012				December 31, 2011			
	Volumes	Unit of Measure	Total Value	Price/ Unit (1)	Volumes	Unit of Measure	Total Value	Price/ Unit (1)
Inventory								
Crude oil	8,464	barrels	$ 821	$ 97.00	5,361	barrels	$ 483	$ 90.10
NGL	3,829	barrels	216	$ 56.41	6,885	barrels	438	$ 63.62
Natural gas (2)	14,453	Mcf	33	$ 2.28	16,170	Mcf	51	$ 3.15
Other	N/A		9	N/A	N/A		6	N/A
Inventory subtotal			1,079				978	
Linefill and base gas								
Crude oil	9,410	barrels	526	$ 55.90	9,366	barrels	514	$ 54.88
Natural gas (2)	14,105	Mcf	49	$ 3.47	14,105	Mcf	48	$ 3.40
NGL	31	barrels	2	$ 64.52	31	barrels	2	$ 64.52
Linefill and base gas subtotal			577				564	
Long-term inventory								
Crude oil	1,848	barrels	138	$ 74.68	1,714	barrels	127	$ 74.10
NGL	150	barrels	8	$ 53.33	150	barrels	8	$ 53.33
Long-term inventory subtotal			146				135	
Total			$ 1,802				$ 1,677	

(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 changes in goodwill for the period indicated (in millions):

	Transportation	Facilities	Supply & Logistics	Total (1)
Balance, December 31, 2011	$ 818	$ 609	$ 427	$ 1,854
2012 Goodwill Related Activity:				
Acquisitions (2)	10			10
Foreign currency translation adjustments	4		1	5
Purchase price accounting adjustments and other (2)	10			10
Balance, March 31, 2012	$ 842	$ 609	$ 428	$ 1,879

(1) As of March 31, 2012, the total carrying amount of goodwill is net of approximately $3 million of accumulated impairment losses.

(2) Goodwill is recorded at the acquisition date based on a preliminary purchase price determination. This preliminary goodwill balance may be adjusted when the purchase price determination is finalized.

Table of Contents

Note 7 Debt

Debt consisted of the following (in millions):

	March 31, 2012	December 31, 2011
SHORT-TERM DEBT		
Credit Facilities:		
Senior secured hedged inventory facility bearing a weighted-average interest rate of 1.5% at December 31, 2011	$	$ 75
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 1.5% and 1.6% at March 31, 2012 and December 31, 2011, respectively (1)	217	32
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% at both March 31, 2012 and December 31, 2011 (2)	37	68
4.25% senior notes due September 2012 (3)	500	500
Other	3	4
Total short-term debt	757	679
LONG-TERM DEBT		
Senior Notes:		
5.63% senior notes due December 2013	250	250
5.25% senior notes due June 2015	150	150
3.95% senior notes due September 2015	400	400
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	350
5.75% senior notes due January 2020	500	500
5.00% senior notes due February 2021	600	600
3.65% senior notes due June 2022 (4)	750	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
5.15% senior notes due June 2042 (4)	500	
Unamortized discounts	(15)	(13)
Senior notes, net of unamortized discounts	5,510	4,262
Credit Facilities and Other:		
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.1% at both March 31, 2012 and December 31, 2011 (2)	79	54
PNG GO Zone term loans, bearing a weighted-average interest rate of 1.5% at both March 31, 2012 and December 31, 2011	200	200
Other	5	4
Total long-term debt	5,794	4,520
Total debt (1) (2) (5)	$ 6,551	$ 5,199

(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.

Table of Contents

(3) Our $500 million 4.25% senior notes will mature in September 2012. The proceeds from these notes are being used to supplement capital available from our hedged inventory facility, to fund working capital needs associated with base levels of waterborne cargos and for seasonal NGL inventory requirements. After these notes mature, we intend to use our credit facilities to finance hedged inventory. Concurrent with the issuance of these senior notes in July 2009, we entered into interest rate swaps. See Note 6 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for further discussion of our interest rate swaps.

(4) In March 2012, we completed the issuance of $750 million, 3.65% senior notes due 2022 and $500 million, 5.15% senior notes due 2042. The senior notes were sold at 99.823% and 99.755% of face value, respectively. Interest payments are due on June 1 and December 1 each year, beginning on December 1, 2012. We used the net proceeds from these offerings to fund a portion of the consideration for the BP NGL Acquisition and for general partnership purposes. See Note 4 for more information regarding this acquisition.

(5) Our fixed-rate senior notes had a face value of approximately $6.0 billion and $4.8 billion as of March 31, 2012 and December 31, 2011, respectively. We estimated the aggregate fair value of these notes as of March 31, 2012 and December 31, 2011 to be approximately $6.7 billion and $5.4 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 approximates fair value as interest rates reflect current market rates. The fair value estimates for both our senior notes and credit facilities are based upon observable market data and are classified within Level 2 of the fair value hierarchy.

Credit Facilities

PAA senior unsecured 364-day revolving credit agreement. In December 2011, we entered into a 364-day credit facility agreement with a borrowing capacity of $1.2 billion. Pursuant to its terms, we had the option to activate the facility at any time over a six-month period. In March 2012, we elected to terminate this credit agreement.

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. At March 31, 2012 and December 31, 2011, we had outstanding letters of credit of approximately $42 million and $33 million, respectively.

Table of Contents

Note 8 Net Income Per Limited Partner Unit

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the three months ended March 31, 2012 and 2011 (amounts in millions, except per unit data):

	Three Months Ended March 31,			
		2012		2011
Numerator for basic and diluted earnings per limited partner unit (1):				
Net income attributable to Plains	$	230	$	182
Less: General partner s incentive distribution		(65)		(50)
Less: General partner 2% ownership		(3)		(3)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$	162	$	129
Denominator:				
Basic weighted average number of limited partner units outstanding		157		143
Effect of dilutive securities:				
Weighted average LTIP units (2)		1		1
Diluted weighted average number of limited partner units outstanding		158		144
Basic net income per limited partner unit	$	1.03	$	0.90
Diluted net income per limited partner unit	$	1.02	$	0.90

(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 and limited partners in accordance with the contractual terms of the partnership agreement.

(2) 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 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for a complete discussion of our LTIP awards.

Note 9 Partners Capital and Distributions

PAA Distributions

The following table details the distributions paid during or pertaining to the first three months of 2012, 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 10, 2012	May 15, 2012 (1)	$ 169	$ 65	$ 3	$ 237	$ 1.0450
January 10, 2012	February 14, 2012	$ 159	$ 63	$ 3	$ 225	$ 1.0250

(1) Payable to unitholders of record at the close of business on May 4, 2012, for the period January 1, 2012 through March 31, 2012.

Table of Contents

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. As such, beginning with the first distribution declared and paid after closing the BP NGL Acquisition, which occurred on April 1, 2012, our general partner agreed to reduce the amount of its incentive distributions by $15 million per year for two years and $10 million per year thereafter. The first incentive distribution reduction related to this acquisition of approximately $4 million will be applied to the May 2012 distribution. See Note 4 for further discussion of the BP NGL Acquisition.

PAA Equity Offerings

During the three months ended March 31, 2012, we completed an equity offering of our common units as shown in the table below (in millions, except unit and per unit data):

Date	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
March 2012 (1)	5,750,000	$ 80.03	$ 460	$ 9	$ (14)	$ 455

(1) This offering of common units was an underwritten transaction that required us to pay a gross spread. The net proceeds from this offering were used to fund a portion of the BP NGL acquisition, to reduce outstanding borrowings under our credit facilities and for general partnership purposes.

LTIP Vesting

In connection with the settlement of vested LTIP awards, we issued 191,812 common units during the three months ended March 31, 2012 with a fair value of approximately $16 million.

Noncontrolling Interests in Subsidiaries

As of March 31, 2012, noncontrolling interests in subsidiaries consisted of the following: (i) an approximate 36 % interest in PNG and (ii) a 25% interest in SLC Pipeline LLC.

Modification of Conversion of PNG Subordinated Units

In February 2012, PNG modified the terms of the first three tranches of the PNG Series B subordinated units held by PAA. The Series B subordinated units do not participate in quarterly distributions. Instead, the Series B subordinated units convert into Series A subordinated units or common units in five distinct tranches upon the achievement of defined benchmarks tied to the amount of capacity in service at Pine Prairie and increases in PNG s quarterly distributions. The modification increased the quarterly distribution benchmark for Tranche 1, 2 and 3 from annualized levels of $1.44 per unit, $1.53 per unit and $1.63 per unit, respectively, to an annualized level of $1.71 per unit. The following table presents the operational and financial benchmarks, as modified, for conversion of the Series B subordinated units into Series A subordinated units for each tranche (units in millions):

	Series B Subordinated Units to Convert into Series A Subordinated Units	Working Gas Storage Capacity (Bcf)	Annualized Distribution Level (1)
Tranche 1	2.6	29.6	$ 1.71
Tranche 2	2.8	35.6	$ 1.71
Tranche 3	2.1	41.6	$ 1.71
Tranche 4	3.0	48.0	$ 1.71
Tranche 5	3.0	48.0	$ 1.80

(1) For satisfaction of this benchmark, PNG must, for two consecutive quarters, (i) maintain distributable cash flow sufficient to pay a quarterly distribution of at least the annualized distribution benchmark on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (ii) distribute available cash of at least the annualized distribution benchmark on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG s general partner s 2% interest and the related distributions on the incentive distribution rights. See Note 5 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for a complete discussion of our Series B subordinated units.

Table of Contents

Noncontrolling Interests Rollforward

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

	For the Three Months Ended March 31,			
	2012		2011	
Beginning balance	$	524	$	231
Sale of noncontrolling interests in a subsidiary				306
Net income attributable to noncontrolling interests		7		3
Distributions to noncontrolling interests		(12)		(5)
Equity compensation expense		1		1
Other comprehensive income/(loss):				
Reclassification adjustments		(6)		
Deferred gain/(loss) on cash flow hedges, net		2		
Ending Balance	$	516	$	536

Note 10 Equity Compensation Plans

For a complete discussion of our equity compensation awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K.

PNG Long-term Incentive Plan Award Modification. In February 2012, the Board of Directors of PNG s general partner approved the modification of certain awards previously granted under the PNG Plan. As a result of the modification, approximately 232,500 equity-classified phantom unit awards will now vest in the following manner: (i) approximately 70,000 awards, with distribution equivalent rights also modified to begin payment in February 2012, will vest upon the date PNG pays an annualized distribution of at least $1.45, (ii) approximately 70,000 awards, with distribution equivalent rights also modified to begin payment in May 2013, will vest upon the date PNG pays an annualized distribution of at least $1.50 and (iii) the remainder, with distribution equivalent rights also modified to begin payment in May 2014, will vest upon the date PNG pays an annualized distribution of at least $1.55. Fifty percent of any awards that have not vested as of the November 2016 distribution date will vest at that time and the remainder will expire. Additionally, 232,500 of equity-classified phantom unit awards with vesting terms originally tied to the conversion of PNG s Series A and Series B subordinated units were modified such that all these awards will now fully vest upon conversion of the Series A subordinated units to common units. Distribution equivalent rights were also granted with respect to these awards beginning in February 2012. There was no financial impact at the time of the modification; however, we anticipate that we will recognize additional equity compensation expense in the future as a result of the modification.

Table of Contents

Other Equity Compensation Information. Our equity compensation activity for awards denominated in PAA and PNG units is summarized in the following table (units in millions):

	PAA Units (1)			PNG Units (2)(3)(4)		
	Units		Weighted Average Grant Date Fair Value per Unit	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2011	4.0	$	43.53	0.8	$	20.55
Granted	0.7	$	65.63	0.1	$	15.05
Vested (5)	(0.8)	$	37.85		$	
Outstanding, March 31, 2012	3.9	$	48.65	0.9	$	17.97

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

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

(3) Amounts include PNG Transaction Grants.

(4) Weighted average grant date fair value per unit for PNG Units outstanding at March 31, 2012, is impacted by the modification of PNG awards during the first quarter of 2012 as discussed above.

(5) Approximately 0.2 million PAA units were issued, net of approximately 0.1 million units withheld for taxes, during the three months ended March 31, 2012. The remaining 0.5 million units that vested were settled in cash.

Class B Units of Plains AAP, L.P. At March 31, 2012 and December 31, 2011, 183,500 AAP LP Class B units were outstanding. As of March 31, 2012, approximately 104,313 of the Class B units outstanding had been earned, 24,250 of which became earned during the three months ended March 31, 2012. A total of 16,500 AAP LP Class B units are reserved for future issuances.

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,			
		2012		2011
Equity compensation expense	$	39	$	20
LTIP unit-settled vestings	$	24	$	
LTIP cash-settled vestings	$	36	$	
DER cash payments	$	2	$	1

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 NYMEX, ICE and over-the-counter 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 positions and ensure that those positions are consistent with our objectives and approved strategies. 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.

Table of Contents

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 (i) to only purchase inventory for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect our operating income and (iii) not to acquire and hold physical inventory or derivatives for the purpose of speculating on commodity price changes. The material commodity-related risks inherent in our business activities can be summarized 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, 2012, net derivative positions related to these activities included:

- An approximate 217,100 barrels per day net long position (total of 6.5 million barrels) associated with our crude oil purchases, which was unwound ratably during April 2012 to match monthly average pricing.

- A net short spread position averaging approximately 21,400 barrels per day (total of 19.6 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through November 2014. These derivatives are time spreads consisting of offsetting purchases and sales between two different months. Our use of these derivatives does not expose us to outright price risk.

- Approximately 9,000 barrels per day on average (total of 5.8 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.

- Approximately 10,500 barrels per day on average (total of 2.6 million barrels) of LLS/WTI crude oil basis swaps from May 2012 through December 2012, which hedge anticipated sales of crude oil. 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.

- An average of 16,200 barrels per day (total of 1.5 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are based on a percentage of WTI through June 2012.

- A short swap position of approximately 21.9 Bcf through December 2012 related to anticipated sales of natural gas.

Inventory Storage We own approximately 78 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. 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, 2012, we had a net short open derivative volume of approximately 7.5 million barrels hedging our inventory or anticipated inventory storage. 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, among other things, 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, 2012, our PLA hedges included (i) a net short position consisting of crude oil futures and swaps for an average of approximately 1,500 barrels per day (total of 2.1 million barrels) through December 2015, (ii) a long put option position of approximately 0.2 million barrels through December 2012 and (iii) a long call option position of approximately 0.6 million barrels through December 2015.

Table of Contents

Base Gas Management Our gas storage facilities require minimum levels of base gas to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge such anticipated purchases of natural gas. As of March 31, 2012, we had a long swap position of approximately 3.5 Bcf through August 2014 related to anticipated base gas purchases.

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, 2012, AOCI includes deferred losses of approximately $82 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 gain related to these instruments is being amortized to interest expense over the terms of the hedged debt instruments.

We have entered into forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2015. The following table summarizes the terms of our forward starting interest rate swaps as of March 31, 2012 (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	6 forward starting swaps (30-year)	$	250	6/17/2013	4.24%	Cash flow hedge
Anticipated debt offering	2 forward starting swaps (30-year)	$	50	6/16/2014	3.94%	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.

Concurrent with our March 2012 senior note issuances, we terminated four ten-year forward starting interest rate swaps. These swaps had an aggregate notional amount of $200 million and an average fixed rate of 3.46%. We paid out cash of approximately $24 million associated with the termination of the swaps.

Concurrent with our January 2011 senior notes issuance, we terminated three forward starting interest rate swaps. These swaps had an aggregate notional amount of $100 million and an average fixed rate of 3.6%. We received cash proceeds of approximately $12 million associated with the termination of these swaps.

During July 2009, concurrent with our senior notes issuance, we entered into four interest rate swaps for which we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminated in September 2011, and two of the swaps will terminate in September 2012. The swaps that terminate in 2012 are designated as fair value hedges.

Table of Contents

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, forwards and options. As of March 31, 2012, AOCI includes net deferred gains of approximately $9 million that relate to open and settled foreign currency derivatives that were designated for hedge accounting. These foreign currency derivatives hedge the cash flow variability associated with CAD-denominated interest payments on CAD-denominated intercompany notes as a result of changes in the exchange rate.

As of March 31, 2012, our outstanding foreign currency derivatives also include derivatives we use to hedge USD-denominated crude oil purchases and sales in Canada. In addition, we may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative, we may enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

The following table summarizes our open forward exchange contracts that exchange CAD for USD on a net basis (in millions):

	CAD	USD	Average Exchange Rate
2012	$ 11	$ 11	CAD $1.01 to USD $1.00
2013	$ 9	$ 9	CAD $1.00 to USD $1.00

Summary of Financial Impact

For derivatives that qualify as a cash flow hedge, changes in fair value of the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. For our interest rate swaps that qualify as a fair value hedge, changes in the fair value of the derivative and changes in the fair value of the underlying hedged item, attributable to the hedged risk, are recognized in earnings each period. 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 operating cash flows in our condensed consolidated statements of cash flows.

Table of Contents

A summary of the impact of our derivative activities recognized in earnings for the three months ended March 31, 2012 and 2011 is as follows (in millions):

	Three Months Ended March 31, 2012			Three Months Ended March 31, 2011		
Location of gain/(loss)	**Derivatives in Hedging Relationships (1)(2)(3)(5)**	**Derivatives Not Designated as a Hedge (4)**	**Total**	**Derivatives in Hedging Relationships (1)(2)(3)**	**Derivatives Not Designated as a Hedge (4)**	**Total**
Commodity Derivatives						
Supply and Logistics segment revenues	$ 34	$ (38)	$ (4)	$ (75)	$ 4	$ (71)
Transportation segment revenues						
Facilities segment revenues	12		12	(1)		(1)
Purchases and related costs	4	1	5			
Field operating costs		2	2		1	1
Interest Rate Derivatives						
Interest expense	(1)		(1)	1		1
Foreign Currency Derivatives						
Supply and Logistics segment revenues		1	1		3	3
Other income/(expense), net	1		1	1		1
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ 50**	**$ (34)**	**$ 16**	**$ (74)**	**$ 8**	**$ (66)**

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(1) Amounts represent derivative gains and losses that were reclassified from AOCI to earnings during the period to coincide with the earnings impact of the respective hedged transaction.

(2) Amounts include losses of approximately $3 million and approximately $8 million for the three months ended March 31, 2012 and 2011, respectively, that represent the ineffective portion of our cash flow hedges. These amounts relate to commodity and interest rate derivatives.

(3) Interest expense includes a net gain of approximately $1 million for both the three months ended March 31, 2012 and 2011, respectively, associated with outstanding interest rate swaps, which are designated as a fair value hedge.

(4) Includes realized and unrealized gains or losses for derivatives not designated for hedge accounting during the period.

(5) Includes unrealized gains of approximately $4 million reclassified from AOCI to earnings during the period to offset a lower of cost or market adjustment relating to the carrying value of PNG s inventory.

Table of Contents

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of March 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	$ 87	Other current assets	$ (54)
	Other long-term assets	7	Other long-term assets	(1)
	Other long-term liabilities	3	Other long-term liabilities	(3)
Interest rate derivatives	Other current assets	1	Other current liabilities	(1)
	Other long-term assets	2	Other long-term liabilities	(65)
Foreign currency derivatives	Other current assets	1		
Total derivatives designated as hedging instruments		$ 101		$ (124)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 44	Other current assets	$ (39)
	Other long-term liabilities	1	Other long-term assets	(6)
Total derivatives not designated as hedging instruments		$ 45		$ (45)
Total derivatives		$ 146		$ (169)

The following table summarizes the derivative assets and liabilities on our condensed consolidated balance sheet on a gross basis as of December 31, 2011 (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	$ 72	Other current assets	$ (47)
	Other long-term assets	20	Other long-term assets	(2)
Interest rate derivatives	Other current assets	1	Other current liabilities	(24)
			Other long-term liabilities	(114)
Foreign currency derivatives	Other current assets	1		
Total derivatives designated as hedging instruments		$ 94		$ (187)

Derivatives not designated as hedging instruments:							
Commodity derivatives	Other current assets	$	87	Other current assets	$	(39)
	Other long-term assets		6	Other long-term assets		(3)
				Other current liabilities		(1)
Total derivatives not designated as hedging instruments		$	93		$	(43)
Total derivatives		$	187		$	(230)

As of March 31, 2012, there was a net loss of approximately $78 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, 2012, we expect to reclassify a net gain of approximately $2 million to earnings in the next twelve months. Of the remaining deferred loss in AOCI, a net gain of approximately $4 million is expected to be reclassified to earnings prior to 2015 with the remaining deferred loss of $84 million being reclassified to earnings through 2045. These amounts are predominantly 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.

During the three months ended March 31, 2012 and March 31, 2011, all of our hedged transactions were probable of occurring. The net deferred gain/(loss), including tax effects, recognized in AOCI for derivatives during the three months ended March 31, 2012 and 2011 are as follows (in millions):

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011
Commodity derivatives, net	$ 25	$ (145)
Foreign currency derivatives, net		(1)
Interest rate derivatives, net	51	2
Total	$ 76	$ (144)

Our accounting policy is to offset derivative assets and liabilities executed with the same counterparty when a master netting agreement exists. Accordingly, we also offset derivative assets and liabilities with amounts associated with cash margin. Our exchange-traded derivatives are transacted through 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, 2012, we had a net broker receivable of approximately $49 million (consisting of initial margin of $74 million reduced by $25 million of variation margin that had been returned to us). As of December 31, 2011, we had a net broker payable of approximately $7 million (consisting of initial margin of $52 million reduced by $59 million of variation margin that had been returned to us). At March 31, 2012 and December 31, 2011, 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.

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, 2012 and December 31, 2011. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, which affects the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of March 31, 2012 (in millions)				Fair Value as of December 31, 2011 (in millions)			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 37	$	$ 2	$ 39	$ 80	$ 1	$ 12	$ 93
Interest rate derivatives		(63)		(63)		(137)		(137)
Foreign currency derivatives		1		1		1		1
Total	$ 37	$ (62)	$ 2	$ (23)	$ 80	$ (135)	$ 12	$ (43)

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

The determination of the fair values above includes not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. The fair value of our commodity derivatives, interest-rate derivatives and foreign currency derivatives includes adjustments for credit risk. Our credit adjustment methodology uses market observable inputs and requires judgment. There were no changes to any of our valuation techniques during the period.

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.

Table of Contents

Level 2

Level 2 of the fair value hierarchy includes 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 or dealer 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 commodity derivatives is based on broker or dealer price quotations or a valuation model. Our valuation models utilize forward commodity prices, which are market observable inputs, and timing estimates, which involve management judgment.

Rollforward of Level 3 Net Liability

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

	Three Months Ended March 31, 2012	2011
Beginning Balance	$ 12	$ (14)
Unrealized gains/(losses):		
Included in earnings (1)	(4)	6
Included in other comprehensive income	3	(2)
Settlements	(12)	32
Derivatives entered into during the period	3	(10)
Transfers out of level 3		(17)
Ending Balance	$ 2	$ (5)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the period	$ (1)	$ (3)

(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.

During the first quarter of 2011, we transferred interest rate and commodity derivatives with an aggregate fair value of $17 million from level 3 to level 2. This transfer resulted from the implementation of additional valuation procedures, using market observable inputs, to validate the broker or dealer price quotations used for fair value measurement. Our policy is to recognize transfers between levels as of the beginning of the reporting period in which the transfer occurred.

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.

Table of Contents

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, will have a materially adverse effect on our financial condition, results of operations or cash flows. Although we believe that our operations are presently in material compliance with applicable requirements, as we acquire and incorporate additional assets it is possible that the Environmental Protection Agency (EPA) or other governmental entities may seek to impose fines, penalties or performance obligations on us (or on a portion of our operations) as a result of any past noncompliance whether such noncompliance initially developed before or after our acquisition.

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In June 2007, the New Jersey Department of Environmental Protection (NJDEP) brought suit in the Superior Court of New Jersey against GATX Corporation (GATX), ExxonMobil and our subsidiary, Plains Products Terminals LLC (PPT), to recover natural resources damages associated with, and to require remediation of, contamination at our Paulsboro terminal facility. ExxonMobil and GATX filed third-party demands against PPT, seeking indemnity and contribution. The natural resources damages were settled with the State of New Jersey. The Settlement Agreement was approved by the court in September 2011. PPT s allocated share of this liability was $550,000, which was paid in November 2011. We remain in dispute with ExxonMobil regarding future remediation responsibility as well as responsibility for prior remediation costs.

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.

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. As we expand our pipeline assets through acquisitions, we typically improve on (reduce) the releases from such assets (in terms of frequency or volume) as we implement our integrity management procedures, remove selected assets from service and invest capital to upgrade the assets. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. These releases can result from unpredictable man-made or natural forces and may reach navigable waters or other sensitive environments. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

At March 31, 2012, our estimated undiscounted reserve for environmental liabilities totaled approximately $74 million, of which approximately $10 million was classified as short-term and $64 million was classified as long-term. At December 31, 2011, our reserve for environmental liabilities totaled approximately $74 million, of which approximately $12 million was classified as short-term and $62 million was classified as long-term. At March 31, 2012 and December 31, 2011, we had recorded receivables totaling approximately $15 million and $47 million, respectively, for amounts probable of recovery under insurance and from third parties under indemnification agreements.

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 claims. 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.

Table of Contents

Insurance

A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and certain assets. The insurance policies are subject to deductibles or self-insured retentions that we consider reasonable. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. In the future, we may not be able to maintain insurance at levels that we consider adequate for rates we consider reasonable. As a result, we may elect to self-insure or utilize higher deductibles in certain insurance programs. For example, the market for hurricane-or windstorm-related property damage coverage has remained difficult the last few years. The amount of coverage available has been limited, and costs have increased substantially with the combination of premiums and deductibles.

In 2011, we elected not to renew our hurricane insurance, and, instead, self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims and which we have renewed at our historic levels. In addition, although we believe that we have established adequate reserves to the extent such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, 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. 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, 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
Three Months Ended March 31, 2011								
Revenues:								
External Customers	$	141	$	118	$	7,435	$	7,694
Intersegment (1)		134		43				177

Total revenues of reportable segments	$	275	$	161	$	7,435	$	7,871
Segment profit (2) (3)	$	137	$	78	$	133	$	348
Maintenance capital	$	18	$	3	$	3	$	24

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(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates. For further discussion, see Analysis of Operating Segments under Item 7 of our 2011 Annual Report on Form 10-K.

(2) Supply and logistics segment profit includes interest expense (related to hedged inventory purchases) of approximately $2 million and $5 million for the three months ended March 31, 2012 and 2011, respectively.

Table of Contents

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

	For the Three Months Ended March 31, 2012	For the Three Months Ended March 31, 2011
Segment profit	$ 380	$ 348
Depreciation and amortization	(60)	(63)
Interest expense	(65)	(65)
Other income/(expense), net	2	(22)
Income tax expense	(20)	(13)
Net income	237	185
Less: Net income attributable to noncontrolling interests	(7)	(3)
Net income attributable to Plains	$ 230	$ 182

Note 14 Related Party Transactions

See Note 9 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Occidental Petroleum Corporation

As of March 31, 2012, 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, 2012 and 2011, we recognized sales and transportation storage 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, 2012	Three Months Ended March 31, 2011
Revenues	$ 455	$ 702
Purchases and related costs	$ 148	$ 74

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, 2012	December 31, 2011
Trade accounts receivable and other receivables	$ 147	$ 132

Accounts payable	$	171	$	155

27

Table of Contents

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 2011 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 2012, our net income attributable to Plains was $230 million, or $1.02 per diluted limited partner unit, representing increases of 26% and 13%, respectively as compared to net income attributable to Plains of $182 million, or $0.90 per diluted limited partner unit recognized during the first three months of 2011. The major items impacting the favorable performance between periods include increased utilization of certain existing transportation assets, incremental fee-based contributions associated with acquisition and expansion capital invested in our transportation and facilities segments and increased lease-gathering volumes and improved unit margins in our supply and logistics segment. The majority of the incremental volumes and a portion of the enhanced unit margins are attributable to technological advancements and their application in the development and expansion of North American crude oil and liquids-rich resource plays. Favorable basis and quality differentials also contributed substantially to margins in our supply and logistics segment, but were largely offset by a $61 million loss related to the mark-to-market impact for derivative instruments (compared to a $20 million gain for the first quarter of 2011). All segments were also negatively impacted by an increase in our equity compensation expense of approximately $19 million.

Table of Contents

During the first three months of 2012, we also raised net proceeds of approximately $1.69 billion through the issuance of two indentures of senior notes and the sale of 5,750,000 common units.

Acquisitions and Internal Growth Projects

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

	Three Months Ended March 31, 2012		Three Months Ended March 31, 2011	
Acquisition capital (1)	$	21	$	769
Internal growth projects		236		97
Maintenance capital		35		24
Total	$	292	$	890

(1) Acquisition capital does not include amounts held in escrow that are related to our acquisition activities and reflected as Restricted cash on our condensed consolidated balance sheet. See Note 4 to our condensed consolidated financial statements for further discussion regarding our acquisition activities.

Internal Growth Projects

The following table summarizes our more notable projects in progress during 2012 and the forecasted expenditures for the year ending December 31, 2012 (in millions):

Projects	**2012**
Eagle Ford Project	$160
Spraberry Area Pipeline Projects	100
Rainbow II Pipeline	75
Mississippian Lime Project	60
Rail Projects	60
PAA Natural Gas Storage (multiple projects)	58
Bakken North	50
Gardendale Gathering System	40
Plains Gas Solutions (multiple projects)	40
St. James Phase IV	40
Yorktown Terminal Project	35
BP NGL Acquisition Related Projects	30
Shafter Expansion	30
Dollard Custom Treating & Truck Terminal	20

Other Projects (1)		202	
		$1,000	
Potential Adjustments for Timing/Scope Refinement (2)	- $50		+ $100
Total Projected Expansion Capital Expenditures	$950	-	$1,100
Maintenance Capital Expenditures	$140	-	$160

(1) Primarily multiple, smaller projects comprised of pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects from prior years.

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

Table of Contents

Results of Operations

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates such segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 13 to our Consolidated Financial Statements included in Part IV of our 2011 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, 2012	Three Months Ended March 31, 2011	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %
Transportation segment profit	$ 162	$ 137	$ 25	18%
Facilities segment profit	90	78	12	15%
Supply and Logistics segment profit	128	133	(5)	(4)%
Total segment profit	380	348	32	9%
Depreciation and amortization	(60)	(63)	3	5%
Interest expense	(65)	(65)		%
Other income/(expense), net	2	(22)	24	109%
Income tax expense	(20)	(13)	(7)	(54)%
Net income	237	185	52	28%
Less: Net income attributable to noncontrolling interests	(7)	(3)	(4)	(133)%
Net income attributable to Plains	$ 230	$ 182	$ 48	26%
Net income attributable to Plains:				
Earnings per basic limited partner unit	$ 1.03	$ 0.90	$ 0.13	14%
Earnings per diluted limited partner unit	$ 1.02	$ 0.90	$ 0.12	13%
Basic weighted average units outstanding	157	143	14	10%
Diluted weighted average units outstanding	158	144	14	10%

Non-GAAP Financial Measures

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

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

Table of Contents

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

	Three Months Ended March 31, 2012	Three Months Ended March 31, 2011	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %
Net income	$ 237	$ 185	$ 52	28%
Add:				
Depreciation and amortization	60	63	(3)	(5)%
Income tax expense	20	13	7	54%
Interest expense	65	65		%
EBITDA	$ 382	$ 326	$ 56	17%
Selected Items Impacting Comparability of EBITDA				
Equity compensation expense (1)	(26)	(14)	(12)	(86)%
Gains/(losses) from derivative activities (2)	(59)	20	(79)	(395)%
Net loss on early repayment of senior notes		(23)	23	N/A
Significant acquisition-related expenses	(4)	(4)		%
Other (3)	(1)	(1)		%
Selected Items Impacting Comparability of EBITDA	$ (90)	$ (22)	$ (68)	(309)%
EBITDA	382	326	56	17%
Selected Items Impacting Comparability of EBITDA	90	22	68	309%
Adjusted EBITDA	$ 472	$ 348	$ 124	36%
Adjusted EBITDA	472	348	124	36%
Interest expense	(65)	(65)		%
Maintenance capital	(35)	(24)	(11)	(46)%
Current income tax expense	(17)	(11)	(6)	(55)%
Equity earnings in unconsolidated entities, net of distributions	(1)	5	(6)	(120)%
Distributions to noncontrolling interests (4)	(12)	(11)	(1)	(9)%
Other		(1)	1	N/A
Implied DCF	$ 342	$ 241	$ 101	42%

(1) Equity compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards are included in our diluted earnings per unit calculation and the majority of the awards are expected to be settled in units. The compensation expense associated with these awards is shown as a selected item impacting comparability in the table above. The portion of compensation expense associated with awards that are certain to be settled in cash are not considered a selected item impacting comparability. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for a comprehensive discussion regarding our equity compensation plans.

(2) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. When applicable, inventory valuation adjustments are presented with related derivative activity. See Note 11 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and hedging activities.

(3) Includes other immaterial selected items impacting comparability.

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

Table of Contents

Analysis of Operating Segments

Transportation Segment

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

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

Operating Results (1) **(in millions, except per barrel amounts)**	**Three Months Ended March 31,** **2012**	**2011**	**Favorable/ (Unfavorable) Variance** **$**	**%**
Revenues (1)				
Tariff activities	$ 278	$ 243	$ 35	14%
Trucking	39	32	7	22%
Total transportation revenues	317	275	42	15%
Costs and Expenses (1)				
Trucking costs	(28)	(22)	(6)	(27)%
Field operating costs (excluding equity compensation expense)	(98)	(91)	(7)	(8)%
Equity compensation expense - operations (2)	(6)	(2)	(4)	(200)%
Segment general and administrative expenses (excluding equity compensation expense)	(22)	(16)	(6)	(38)%
Equity compensation expense - general and administrative (2)	(8)	(7)	(1)	(14)%
Equity earnings in unconsolidated entities	7		7	N/A
Segment profit	$ 162	$ 137	$ 25	18%
Maintenance capital	$ 24	$ 18	$ (6)	(33)%
Segment profit per barrel	$ 0.56	$ 0.51	$ 0.05	10%

Average Daily Volumes **(in thousands of barrels per day) (3)**	**Three Months Ended March 31,** **2012**	**2011**	**Favorable/ (Unfavorable) Variance** **Volumes**	**%**
Tariff activities				
All American	25	35	(10)	(29)%
Basin	497	427	70	16%
Capline	122	188	(66)	(35)%
Line 63/Line 2000	118	94	24	26%
Salt Lake City Area Systems	130	136	(6)	(4)%
Permian Basin Area Systems	454	392	62	16%
Mid-Continent Area Systems	217	215	2	1%
Manito	68	67	1	1%
Rainbow	142	179	(37)	(21)%
Rangeland	64	54	10	19%

Refined products	112	97	15	15%
Other	1,109	1,020	89	9%
Tariff activities total	3,058	2,904	154	5%
Trucking	108	99	9	9%
Transportation segment total	3,166	3,003	163	5%

Table of Contents

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

(2) Equity compensation expense shown in the table above includes that portion of equity compensation expense represented by outstanding awards under the LTIP Plans that, pursuant to the terms of such awards, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of the table under Results of Operations Non-GAAP Financial Measures excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for additional discussion regarding our equity compensation plans.

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

Tariffs and other fees on our pipeline systems vary by receipt point and delivery point. The segment profit generated by our tariff and other fee-related activities depends on the volumes transported on the pipeline and the level of the tariff and other fees charged as well as the fixed and variable field costs of operating the pipeline. Segment profit from our pipeline capacity leases generally reflects a negotiated amount.

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

Operating Revenues and Volumes. As noted in the table above, our total transportation segment revenues, net of trucking costs, and volumes increased year-over-year for the three months ended March 31, 2012 compared to the three months ended March 31, 2011. Overall, our volumes have been favorably impacted by increased producer drilling activities, primarily in the Bakken, Eagle Ford, Permian Basin, Western Oklahoma and Texas Panhandle producing regions. Noteworthy variances on our individual pipeline systems for the three months ended March 31, 2012 as compared to the same 2011 period include (i) increased volumes on our Basin and Permian Basin Area Systems, which were favorably impacted by expanded drilling, (ii) increased volumes on our Line 63/Line 2000 systems due to increased movements of SJV crude oil by LA Basin refiners, (iii) decreased volumes on our Rainbow System related to a third-party competitor pipeline placed into service during the third quarter of 2011, (iv) decreased volumes on our Capline Pipeline System, primarily related to shifts in refinery supply and (v) decreased volumes on our All American System related to field production declines and maintenance activities at the production facilities.

In addition to the impact of the volumetric variances discussed above, our transportation segment results were impacted by the following for the three months ended March 31, 2012 compared to the three months ended March 31, 2011:

- Rate Changes Revenues were favorably impacted by increasing tariff rates on our Canadian pipelines, as well as increases in rates on our FERC-regulated pipelines due to upward indexing effective July 1, 2011.

- Loss Allowance Revenue As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative-related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. The loss allowance revenue increased by approximately $11 million for the three months ended March 31, 2012 compared to the three months ended March 31, 2011. These increases were primarily due to higher volumes and were also impacted by a higher average realized price per barrel during the 2012 comparative period (including the impact of gains from derivative activities).

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the three months ended March 31, 2012 compared to the three months ended March 31, 2011 consistent with the overall growth in segment volumes and remained relatively constant on a per barrel basis during each of those periods.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation expense as discussed below) increased during the three months ended March 31, 2012 compared to the three months ended March 31, 2011 due to the overall growth of the segment as well as costs associated with acquisition activities.

Table of Contents

Equity Compensation Expense. Equity compensation expense increased for the three months ended March 31, 2012 compared to the three months ended March 31, 2011, primarily due to (i) an increase in unit price of $5 for the first quarter of 2012 compared to a less than $1 increase for the first quarter of 2011 and (ii) additional awards that have been deemed probable of occurring. The increase in unit price impacts the fair value of our liability-classified awards. A majority of our equity compensation awards (including the Class B units) contain performance conditions contingent upon achieving certain distribution levels. For awards with performance conditions (such as distribution targets), expense is accrued over the service period only if the performance condition is considered probable of occurring. When awards with performance conditions that were previously considered improbable become probable, we incur additional expense in the period that our probability assessment changes. This is necessary to bring the accrued liability associated with these awards up to the level it would have been if we had been accruing for these awards since the grant date. At March 31, 2012, we determined that a PAA distribution level of $4.50 was probable of occurring, and we incurred additional expense as a result of such determination. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 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 in the three months ended March 31, 2012 compared to the three months ended March 31, 2011 is primarily due to increased spending on pipeline integrity projects as well as timing of repairs between years.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities increased for the three months ended March 31, 2012 compared to the three months ended March 31, 2011 primarily related to increased earnings for the 2012 comparative period from our 34% interest in White Cliffs Pipeline LLC. The favorable year-over-year variance was also impacted by a loss incurred for an environmental liability in February 2011 related to an incident involving Settoon Towing LLC, in which we have a 50% interest, for which a similar loss was not experienced in the current period.

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. 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, 2012**	**2011**	**Favorable/ (Unfavorable) Variance $**	**%**
Storage and terminalling revenues (1)	$ 165	$ 143	$ 22	15%
Natural gas sales (2)	71	18	53	294%
Storage related costs (natural gas related)	(7)	(6)	(1)	(17)%
Natural gas sales costs (2)	(67)	(18)	(49)	(272)%
Field operating costs (excluding equity compensation expense)	(46)	(40)	(6)	(15)%

Equity compensation expense - operations (3)		(1)		(1)			%
Segment general and administrative expenses (excluding equity compensation expense)		(14)		(14)			%
Equity compensation expense - general and administrative (3)		(11)		(4)		(7)	(175)%
Segment profit	$	90	$	78	$	12	15%
Maintenance capital	$	7	$	3	$	(4)	(133)%
Segment profit per barrel	$	0.33	$	0.34	$	(0.01)	(3)%

Table of Contents

Volumes (4)(5)	Three Months Ended March 31, 2012	2011	Favorable/ (Unfavorable) Variance Volumes	%
Crude oil, refined products and NGL storage (average monthly capacity in millions of barrels)	78	67	11	16%
Natural gas storage (average monthly capacity in billions of cubic feet)	76	59	17	29%
NGL fractionation (average throughput in thousands of barrels per day)	11	11		%
Facilities segment total (average monthly capacity in millions of barrels)	91	77	14	18%

(1) Includes 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 that portion of equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of such awards, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of the table under Results of Operations Non-GAAP Financial Measures excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for additional discussion regarding our equity compensation plans.

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

(5) Facilities total calculated as the sum of: (i) crude oil, refined products and NGL storage capacity; (ii) natural gas capacity divided by 6 to account for the 6:1 mcf of gas to crude Btu equivalent ratio and further divided by 1,000 to convert to monthly volumes in millions; and (iii) 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 table above, our facilities segment revenues, less storage related costs and natural gas purchases, and volumes increased for the three months ended March 31, 2012 compared to March 31, 2011. The significant variances in revenues and average monthly volumes between the comparative periods are primarily due to our ongoing acquisition and expansion activities as discussed below:

- PNG Acquisition and Expansion Projects   Revenues and volumes for the three months ended March 31, 2012 were favorably impacted by (i) contributions from a full quarter of operations at PNG s Southern Pines facility, which was acquired in February 2011, (ii) incremental revenues from the addition of 8 Bcf of working gas capacity at the Pine Prairie facility during the second quarter of 2011 and (iii) more favorable results from PNG s commercial optimization group, primarily due to an increase in volumes of natural gas sold.

- Other Acquisitions and Major Expansion Projects   Expansion projects that were completed in phases throughout recent years at some of our major terminal locations also favorably impacted revenues and volumes. We estimate that these expansion projects, as well as our December 2011 Yorktown terminal acquisition, increased our revenues by approximately $9 million on a combined basis for the three months ended March 31, 2012 compared to the three months ended March 31, 2011. The addition of our Yorktown facility and expansions at our Cushing facility comprised the majority of the 11 million barrel increase in total crude oil, refined products and NGL storage average monthly capacity in the three months ended March 31, 2012 as compared to the three months ended March 31, 2011.

Table of Contents

- Other Revenues for the three months ended March 31, 2012 compared to the three months ended March 31, 2011 also increased as a result of general escalations on existing leases.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) in general remained relatively constant on a per barrel basis during the comparative periods presented. The absolute increase in costs during each comparable period is consistent with the overall growth of the segment through expansion projects at some of our major terminal, storage and gas processing locations and acquisition activity.

Equity Compensation Expense. Equity compensation expense increased for the comparative periods presented. See Results of Operations Analysis of Operating Segments Transportation Segment Equity Compensation Expense above for a discussion regarding such increases. Also, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for additional information on our equity compensation plans.

Maintenance Capital. The increase in maintenance capital in the three months ended March 31, 2012 over the three months ended March 31, 2011 is primarily a result of timing of integrity spending.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil and NGL volumes. These revenues also include the sale of additional barrels exchanged through buy/sell arrangements entered into to supplement the margins of the gathered and bulk-purchased volumes. We do not anticipate that future changes in revenues will be a primary driver of segment profit. Generally, we expect our segment profit to increase or decrease directionally with (i) increases or decreases in our supply and logistics segment volumes (which consist of lease gathered crude oil purchase volumes, 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 will vary from period to period.

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

Operating Results (1)	**Three Months Ended March 31,**		**Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel amounts)	**2012**	**2011**	**$**	**%**
Revenues	$ 8,877	$ 7,435	$ 1,442	19%
Purchases and related costs (2)	(8,608)	(7,206)	(1,402)	(19)%
Field operating costs (excluding equity compensation expense)	(101)	(67)	(34)	(51)%

Equity compensation expense - operations (3)		(1)				(1)	N/A
Segment general and administrative expenses (excluding equity compensation expense)		(27)		(23)		(4)	(17)%
Equity compensation expense - general and administrative (3)		(12)		(6)		(6)	(100)%
Segment profit	$	128	$	133	$	(5)	(4)%
Maintenance capital	$	4	$	3	$	(1)	(33)%
Segment profit per barrel	$	1.51	$	1.65	$	(0.14)	(8)%

Table of Contents

Average Daily Volumes (4) **(in thousands of barrels per day)**	**Three Months Ended March 31, 2012**	**2011**	**Favorable/ (Unfavorable) Variance Volumes**	**%**
Crude oil lease gathering purchases	798	723	75	10%
NGL sales	134	151	(17)	(11)%
Waterborne cargos		26	(26)	N/A
Supply and Logistics segment total	932	900	32	4%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged crude oil inventory purchases) of approximately $2 million and $5 million for the three months ended March 31, 2012 and 2011, respectively.

(3) Equity compensation expense presented in the reconciliation to segment profit above includes that portion of equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of such awards, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented in the Selected Items Impacting Comparability section of the table under Results of Operations Non-GAAP Financial Measures excludes this portion of the equity compensation expense. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for additional discussion regarding our equity compensation plans.

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

The New York Mercantile Exchange (NYMEX) benchmark price of crude oil ranged from approximately $95 to $111 per barrel and $84 to $107 per barrel during the first quarter of 2012 and 2011, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the sales and purchases, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those sales and purchases will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased for the three months ended March 31, 2012 and 2011 resulting from higher commodity prices and increases in volumes in the comparative 2012 period.

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

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

Operating Revenues and Volumes. Revenues, net of purchases and related costs, increased by approximately $40 million or 17% in the first quarter of 2012 compared to the first quarter of 2011. This increase in net revenues was driven by:

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

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

Table of Contents

- 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. As the infrastructure in these producing regions continues to be developed, we may not experience the same opportunities for enhanced margins that we are currently experiencing. We believe the fundamentals of our business remain strong; however, a normalization of margins may occur as the logistics challenges are addressed. (See Items 1 and 2. Business and Properties Description of Segments and Associated Assets *Supply & Logistics Segment* Impact of Commodity Price Volatility and Dynamic Market Conditions on Our Business Model for further discussion regarding our business model, including diversification and utilization of our asset base among varying demand- and supply-driven markets.)

These increases were partially offset by the impact of the mark-to-market valuation of our derivative activities on our net revenues as shown in the table below (in millions):

	Three Months Ended March 31, 2012	2011	Variance
Gains/(losses) from derivative activities (1)	$ (61)	$ 20	$ (81)

(1) Includes mark-to-market gains and losses resulting from derivative instruments that are related to underlying activities in future periods or the reversal of mark-to-market gains and losses from the prior period. See Note 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, 2012 compared to the three months ended March 31, 2011 primarily due to an increase in trucking costs, particularly the increased use of third-party contractors, associated with the increase in lease gathered volumes in the regions discussed above.

General and Administrative Expenses. General and administrative expenses (excluding equity compensation expense as discussed below) increased during the three months ended March 31, 2012 compared to the three months ended March 31, 2011 due to legal fees associated with the resolution of certain outstanding issues.

Equity Compensation Expense. Equity compensation expense increased for the comparative periods presented. See Results of Operations Analysis of Operating Segments Transportation Segment Equity Compensation Expense above for a discussion regarding such increases. Also, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2011 Annual Report on Form 10-K for additional information on our equity compensation plans.

Other Income and Expenses

Depreciation and Amortization

Depreciation and Amortization. Depreciation and amortization expense was $60 million for the three months ended March 31, 2012 compared to $63 million for the three months ended March 31, 2011, reflecting a net gain in the 2012 period of approximately $5 million recognized upon disposition of certain assets as compared to a net loss in the 2011 period of approximately $1 million for asset dispositions and impairments for assets taken out of service. Expense was also lower in the 2012 period as a result of the extension of depreciable lives of several of our crude oil and other storage facilities and pipeline systems. These comparative period decreases were partially offset by an increased amount of assets resulting from acquisition activities completed in 2011 as well as various internal growth projects in both years.

Other Income/(Expense), Net

Other income/(expense), net was a net gain of approximately $2 million for the three months ended March 31, 2012, compared to a net loss of approximately $22 million for the three months ended March 31, 2011. This variance is primarily due to the loss related to the early redemption of our $200 million, 7.75% senior notes in February 2011.

Table of Contents

Income Tax Expense

Current income tax expense increased for the three months ended March 31, 2012 compared to the three months ended March 31, 2011 primarily due to an increase in the level of taxable earnings in our entities subject to Canadian federal and provincial taxes and other adjustments. In addition, payments of interest and dividends from our Canadian entities to other affiliates are subject to Canadian withholding tax which is also treated as income tax expense.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our cash flow from operations as further discussed below in the section entitled Cash Flow from Operations and (ii) borrowings under our credit facilities. Our primary cash requirements include, but are not limited to (i) ordinary course of business uses, such as the payment of amounts related to the purchase of crude oil and other products and other expenses and interest payments on our outstanding debt, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses, (iv) repayment of principal on our long-term debt and (v) distributions to our unitholders and general partner. We generally expect to fund our short-term cash requirements through our primary sources of liquidity. In addition, we generally expect to fund our long-term needs, such as those resulting from expansion activities or acquisitions, through a variety of sources (either separately or in combination), which may include operating cash flows, borrowings under our credit facilities, and/or the issuance of additional equity or debt securities. As of March 31, 2012, we had a working capital deficit of approximately $276 million and approximately $2.34 billion of liquidity available to meet our other ongoing operational, investing and finance needs as noted below (in millions):

		As of March 31, 2012
Availability under PAA senior unsecured revolving credit facility	$	1,373
Availability under PAA senior secured hedged inventory facility		821
Availability under PNG senior unsecured revolving credit facility		131
Cash and cash equivalents		14
Total	$	2,339

We believe that we have and will continue to have the ability to access our credit facilities, which we use to meet our short-term cash needs. We believe that our financial position remains strong and we have sufficient liquidity; however, extended disruptions in the financial markets and/or energy price volatility that adversely affect our business may have a materially adverse effect on our financial condition, results of operations or cash flows. Also, see Risk Factors in Item 1A of our 2011 Annual Report on Form 10-K for further discussion regarding such risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

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

Cash Flow from Operations

For a comprehensive discussion of the primary drivers of our cash flow from operations, 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 2011 Annual Report on Form 10-K.

Net cash provided by operating activities was approximately $317 million for the first three months of 2012, which was down $337 million as compared to $654 million for the first three months of 2011. The cash provided by operating activities reflects cash generated by our recurring operations, and is also significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first quarters of both 2011 and 2012, we decreased our NGL inventory resulting from end users demand for heating requirements during the winter heating season. However, we experienced a higher liquidation of NGL inventory during the first three months of 2011 as compared to the first three months of 2012 primarily due to reduced demand during the 2011-2012 winter heating season as a result of unusually warmer temperatures. 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 contango market activities and NGL business, as well as refinancing of our debt maturities. Our financing activities have primarily consisted of equity offerings, senior notes offerings and borrowings and repayments under our credit facilities.

Registration Statements

We periodically access the capital markets for both equity and debt financing. We have filed with the SEC a universal shelf registration statement that, subject to effectiveness at the time of use, allows us to issue up to an aggregate of $2.0 billion of debt or equity securities (Traditional Shelf). At March 31, 2012, we had $2.0 billion of unsold securities available under the Traditional Shelf. We also have access to a universal shelf registration statement (WKSI Shelf), which provides us with the ability to offer and sell an unlimited amount of debt and equity securities, subject to market conditions and our capital needs. The March 2012 offerings of our $750 million, 3.65% senior notes due 2022 and our $500 million, 5.15% senior notes due 2042 as well as the March 2012 equity offering, as discussed further below, were all conducted under the WKSI Shelf.

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

Equity and Debt Offerings

PAA Equity Offering. In March 2012, we completed the sale and issuance of 5,750,000 common units at $80.03 per unit for net proceeds of approximately $455 million. The net proceeds include our general partner s proportionate capital contribution and are reflected net of costs associated with the offering. We used the net proceeds to fund a portion of the BP NGL Acquisition, to temporarily reduce outstanding borrowings under our credit facilities and for general partnership purposes. Amounts repaid under our credit facilities may be reborrowed to fund our ongoing capital program, potential future acquisitions or for general partnership purposes.

Senior Notes. We had several issues of senior debt outstanding at March 31, 2012 totaling approximately $6.0 billion, excluding discounts. These issues of senior debt range in size from $150 million to $750 million and mature at various dates between 2012 and 2042. See Note 7 to our condensed consolidated financial statements.

In March 2012, we completed the sale and issuance of $750 million, 3.65% senior notes due 2022 and $500 million, 5.15% senior notes due 2042. The senior notes were sold at 99.823% and 99.755% of face value, respectively. Interest payments are due on June 1 and December 1 each year beginning on December 1, 2012. We used the net proceeds from these offerings to fund a portion of the consideration for the BP NGL Acquisition and for general partnership purposes.

Credit Agreements

General. During the three months ended March 31, 2012, we had net borrowings on our credit agreements, which include our revolving credit facilities, our GO Zone term loans and our hedged inventory facility, in the aggregate of approximately $104 million.

During the three months ended March 31, 2011, we had net repayments on our revolving credit facilities and our hedged inventory facility in the aggregate of approximately $906 million. The net repayments were primarily attributed to funds received from our January 2011 debt offering and March 2011 equity offering as well as from sales of NGL inventory that was liquidated during the quarter.

PAA senior unsecured 364-day revolving credit agreement. In March 2012, we elected to terminate an unactivated 364-day credit facility agreement that had a borrowing capacity of $1.2 billion.

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

In addition to operating needs discussed above, we also use cash for our acquisition activities, internal growth projects and distributions paid to our unitholders, general partner and noncontrolling interests. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See Internal Growth Projects above and Acquisitions and Internal Growth Projects under Item 7 of our 2011 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 the acquisitions and the timing of certain cash payments, the net cash paid may differ significantly from the total price of the acquisitions completed during the year.

In December 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company for a total consideration of approximately $1.67 billion, which closed on April 1, 2012 (see Note 4 to our condensed consolidated financial statements). As of March 31, 2012, we had approximately $1.63 billion in restricted cash held by an escrow agent in contemplation of closing this acquisition and prior to December 31, 2011, we paid a cash deposit of $50 million upon signing. See Note 4 for further discussion of this acquisition.

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, 2012, we will pay a quarterly distribution of $1.045 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 7.7%. 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 2011 Annual Report on Form 10-K for additional discussion on distributions.

In order to enhance our distribution coverage ratio and liquidity in connection with a significant acquisition, our general partner has, from time to time, agreed to reduce the amounts due to it as incentive distributions. As such, beginning with the first distribution declared and paid after closing the BP NGL Acquisition, which occurred on April 1, 2012, our general partner agreed to reduce the amount of its incentive distributions by $15 million per year for two years and $10 million per year thereafter. The first incentive distribution reduction related to this acquisition of approximately $4 million will be applied to the May 2012 distribution. See Note 4 to our condensed consolidated financial statements for further discussion of the BP NGL Acquisition.

Distributions to noncontrolling interests. We paid approximately $12 million and $5 million for distributions to our noncontrolling interests during the three months ended March 31, 2012 and 2011, respectively. These amounts represent distributions paid on interests in PNG and SLC that are not owned by us.

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

Table of Contents

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.

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, 2012 (in millions):

	2012	2013	2014	2015	2016	2017 and Thereafter	Total
Long-term debt, including current maturities and related interest payments (1)	$ 831	$ 568	$ 303	$ 846	$ 728	$ 6,813	$ 10,089
Leases (2)	66	65	54	46	37	303	571
Other obligations (3)	154	87	42	34	22	106	445
BP NGL acquisition (4)	1,670						1,670
Subtotal	2,721	720	399	926	787	7,222	12,775
Crude oil, natural gas, NGL and other purchases (5)	5,342	1,307	422	247	236	837	8,391
Total	$ 8,063	$ 2,027	$ 821	$ 1,173	$ 1,023	$ 8,059	$ 21,166

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(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, 2012, 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 used in our gathering activities.

(3) Includes (i) other long-term liabilities, (ii) storage and transportation agreements and (iii) commitments related to our capital expansion projects. Excludes a non-current liability of approximately $69 million related to derivative activity included in Crude oil, natural gas, NGL and other purchases.

(4) In December 2011, we entered into a definitive agreement to acquire all of the outstanding shares of BP Canada Energy Company for total consideration of approximately $1.67 billion. This acquisition closed on April 1, 2012. As of March 31, 2012, we had approximately $1.63 billion in restricted cash held by an escrow agent in contemplation of this acquisition and prior to December 31, 2011, we paid a cash deposit of $50 million upon signing. See Note 4 to our condensed consolidated financial statements for further discussion of this acquisition.

Table of Contents

(5) Amounts are primarily based on estimated volumes and market prices based on average activity during March 2012. 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, 2012 and December 31, 2011, we had outstanding letters of credit of approximately $42 million and $33 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 2011 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 these words, however, does not mean that the statements are not forward-looking. These statements reflect our current views with respect to future events, based on what we believe to be reasonable assumptions. Certain factors could cause actual results to differ materially from the results anticipated in the forward-looking statements. The most important of these factors include, but are not limited to:

- failure to integrate the BP NGL Acquisition;

- failure to implement or capitalize on planned internal growth projects;

- 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;

- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);

- environmental liabilities or events that are not covered by an indemnity, insurance or existing reserves;

- abrupt or severe declines or interruptions in outer continental shelf production located offshore California and transported on our pipeline systems;

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

- the availability of adequate third-party production volumes for transportation and marketing in the areas in which we operate and other factors that could cause declines in volumes shipped on our pipelines by us and third-party shippers, such as declines in production from existing oil and gas reserves or failure to develop additional oil and gas reserves;

- 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;

- the availability of, and our ability to consummate, acquisition or combination opportunities;

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

- 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 natural gas storage facilities;

- 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 2011 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.

Table of Contents

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

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

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

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

	Fair Value	Effect of 10% Price Increase	Effect of 10% Price Decrease
Crude oil:			
Futures contracts	$ 18	$ (14)	$ 14
Swaps and options contracts	19	$ (26)	$ 27
NGL and other:			
Swaps and options contracts	2	$ 1	$ (1)
Total Fair Value	$ 39		

The fair value of our exchange-traded derivatives is based on quoted market prices obtained from the NYMEX or ICE. The fair value of our over-the-counter swaps and options contracts is estimated based on quoted prices from various sources such as independent reporting services, industry publications and brokers. The assumptions used in these estimates as well as the source for the estimates are maintained by the independent risk control function. See Note 11 to our condensed consolidated financial statements for further discussion. Price-risk sensitivities were calculated by assuming an across-the-board 10% increase or decrease in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. In the event of an actual 10% change in near-term crude prices, the fair value of our derivative portfolio would typically change less than that shown in the table as changes in near-term prices are not typically mirrored in delivery months further out.

Table of Contents

Interest Rate Risk

We use both fixed and variable rate debt, and are exposed to interest rate risk. Therefore, from time to time we use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, outstanding debt instruments. All of our senior notes are fixed rate notes and thus not subject to interest rate risk. The majority of our variable rate debt at March 31, 2012, approximately $600 million (which includes $150 million of interest rate derivatives that swap fixed rate debt for floating and excludes $100 million 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 1.9% is based upon rates in effect during the three months ended March 31, 2012. The fair value of our interest rate derivatives is an unrealized loss of approximately $63 million as of March 31, 2012. A 10% increase in the forward LIBOR curve as of March 31, 2012 would result in an increase of approximately $35 million to the fair value of our interest rate derivatives. A 10% decrease in the forward LIBOR curve as of March 31, 2012 would result in a decrease of approximately $35 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.

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 2011 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.

Table of Contents

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, 2012

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

Date: May 8, 2012

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

Table of Contents

EXHIBIT INDEX

3.1	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	Amendment No. 2 dated November 15, 2006 to Third 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 November 21, 2006).
3.4	Amendment No. 3 dated August 16, 2007 to Third 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 August 22, 2007).
3.5	Amendment No. 4 effective as of January 1, 2007 to Third 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 April 15, 2008).
3.6	Amendment No. 5 dated May 28, 2008 to Third 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 May 30, 2008).
3.7	Amendment No. 6 dated September 3, 2009 to Third 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 September 3, 2009).
3.8	Amendment No. 7 dated April 1, 2012 to The Third 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 April 5, 2012).
3.9	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).
3.10	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).
3.11	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).
3.12	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).
3.13	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).
3.14	

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).

Table of Contents

3.15	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).
3.16	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).
3.17	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	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 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 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	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).
4.4	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).
4.5	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).
4.6	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).
4.7	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).
4.8	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).
4.9	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).
4.10	

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).

4.11	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 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 July 23, 2009).
4.12	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).
4.13	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).
4.14	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).
4.15	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).
4.16	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).
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

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Filed herewith