PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
August 05, 2011
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 June 30, 2011

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 August 2, 2011, there were 149,357,119 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)

	June 30, 2011 (unaudited)	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 23	$ 36
Restricted cash		20
Trade accounts receivable and other receivables, net	3,047	2,746
Inventory	1,452	1,491
Other current assets	111	88
Total current assets	4,633	4,381
PROPERTY AND EQUIPMENT	8,498	7,814
Accumulated depreciation	(1,222)	(1,123)
	7,276	6,691
OTHER ASSETS		
Goodwill	1,692	1,376
Linefill and base gas	549	519
Long-term inventory	136	154
Investments in unconsolidated entities	195	200
Other, net	432	382
Total assets	$ 14,913	$ 13,703
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 3,265	$ 2,738
Short-term debt	536	1,326
Other current liabilities	182	151
Total current liabilities	3,983	4,215
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $14 and $12, respectively	4,761	4,363
Long-term debt under credit facilities and other	234	268
Other long-term liabilities and deferred credits	252	284
Total long-term liabilities	5,247	4,915

COMMITMENTS AND CONTINGENCIES (NOTE 13)				
PARTNERS CAPITAL				
Common unitholders (149,357,119 and 141,199,175 units outstanding, respectively)		5,022		4,234
General partner		128		108
Total partners capital excluding noncontrolling interests		5,150		4,342
Noncontrolling interests		533		231
Total partners capital		5,683		4,573
Total liabilities and partners capital	$	14,913	$	13,703

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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited)		(unaudited)	
REVENUES				
Supply & Logistics segment revenues	$ 8,586	$ 5,901	$ 16,021	$ 11,813
Transportation segment revenues	147	139	288	277
Facilities segment revenues	126	84	244	158
Total revenues	8,859	6,124	16,553	12,248
COSTS AND EXPENSES				
Purchases and related costs	8,202	5,641	15,281	11,263
Field operating costs	223	171	420	334
General and administrative expenses	73	56	143	117
Depreciation and amortization	63	64	126	131
Total costs and expenses	8,561	5,932	15,970	11,845
OPERATING INCOME	298	192	583	403
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	4	1	5	2
Interest expense (net of capitalized interest of $6, $3, $11 and $9, respectively)	(62)	(62)	(128)	(120)
Other income/(expense), net	2	2	(20)	(1)
INCOME BEFORE TAX	242	133	440	284
Current income tax benefit/(expense)	(8)	1	(18)	(1)
Deferred income tax benefit/(expense)	(1)	(1)	(4)	1
NET INCOME	233	133	418	284
Less: Net income attributable to noncontrolling interests	(8)	(2)	(10)	(2)
NET INCOME ATTRIBUTABLE TO PLAINS	$ 225	$ 131	$ 408	$ 282
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 171	$ 90	$ 305	$ 201
GENERAL PARTNER	$ 54	$ 41	$ 103	$ 81
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.14	$ 0.65	$ 2.04	$ 1.45
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.13	$ 0.65	$ 2.03	$ 1.45
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	149	136	146	136
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	150	137	147	137

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 CASH FLOWS

(in millions)

	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 418	$ 284
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	126	131
Equity compensation expense	46	33
Gain on sale of linefill	(15)	(17)
Net cash received for terminated interest rate or foreign currency hedging instruments	12	
Other	5	8
Changes in assets and liabilities, net of acquisitions	380	(156)
Net cash provided by operating activities	972	283
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions, net of cash acquired	(751)	(184)
Change in restricted cash	20	
Additions to property, equipment and other	(287)	(215)
Net cash received/(paid) for sales and purchases of linefill and base gas	(6)	18
Other investing activities	(3)	3
Net cash used in investing activities	(1,027)	(378)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on PAA s revolving credit facility	(592)	(150)
Net borrowings/(repayments) on PNG s revolving credit facility	(34)	205
Net borrowings/(repayments) on PAA s hedged inventory facility	(200)	100
Proceeds from the issuance of senior notes	597	
Repayments of senior notes	(200)	
Net proceeds from the issuance of common units (Note 10)	503	
Cash received for sale of noncontrolling interest in a subsidiary	370	268
Distributions paid to common unitholders (Note 10)	(280)	(253)
Distributions paid to general partner (Note 10)	(102)	(82)
Distributions to noncontrolling interests	(16)	(1)
Other financing activities	(3)	(1)
Net cash provided by financing activities	43	86
Effect of translation adjustment on cash	(1)	(1)
Net decrease in cash and cash equivalents	(13)	(10)
Cash and cash equivalents, beginning of period	36	25
Cash and cash equivalents, end of period	$ 23	$ 15
Cash paid for interest, net of amounts capitalized	$ 123	$ 123
Cash paid for income taxes, net of amounts refunded	$ 1	$ 20

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, 2010	141	$	4,234	$ 108	$ 4,342	$ 231	$ 4,573
Net income			305	103	408	10	418
Sale of noncontrolling interest in a subsidiary (Note 10)			63	1	64	306	370
Distributions			(280)	(102)	(382)	(16)	(398)
Issuance of common units	8		493	10	503		503
Issuance of common units under LTIP			13		13		13
Other comprehensive income			186	4	190		190
Equity compensation expense			8	4	12	2	14
Balance, June 30, 2011	149	$	5,022	$ 128	$ 5,150	$ 533	$ 5,683

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010
	(unaudited)		(unaudited)	
Net income	$ 233	$ 133	$ 418	$ 284
Other comprehensive income/(loss)	220	(45)	190	19
Comprehensive income	453	88	608	303
Less: Comprehensive income attributable to noncontrolling interests	(8)	(2)	(10)	(2)
Comprehensive income attributable to Plains	$ 445	$ 86	$ 598	$ 301

CONDENSED CONSOLIDATED STATEMENT OF

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2010	$ (79)	$ 198	$ (1)	$ 118
Reclassification adjustments	233			233
Deferred loss on cash flow hedges, net of tax	(95)			(95)
Currency translation adjustment		52		52
Total period activity	138	52		190
Balance, June 30, 2011	$ 59	$ 250	$ (1)	$ 308

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, refined products and LPG. Through our general partner interest and majority equity ownership position in PAA Natural Gas Storage, L.P. (NYSE: PNG), we also engage in the development and operation of natural gas storage facilities. Our business activities are conducted through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 14 for further detail 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

The following 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
ICE	=	IntercontinentalExchange
IFRS	=	International Financial Reporting Standards
LIBOR	=	London Interbank Offered Rate
LPG	=	Liquefied petroleum gas and other natural gas-related products
LTIPs	=	Long-term incentive plans

Mcf	=	Thousand cubic feet
MLP	=	Master limited partnership
MTBE	=	Methyl tertiary-butyl ether
Nexen	=	Nexen Holdings U.S.A. Inc.
NPNS	=	Normal purchases and normal sales
NYMEX	=	New York Mercantile Exchange
Pacific	=	Pacific Energy Partners, L.P.
PLA	=	Pipeline loss allowance
PNG	=	PAA Natural Gas Storage, L.P.
PNGS	=	PAA Natural Gas Storage, LLC
RMPS	=	Rocky Mountain Pipeline System
SEC	=	Securities and Exchange Commission
SG Resources	=	SG Resources Mississippi, LLC
U.S. GAAP	=	Generally accepted accounting principles in the United States
USD	=	United States dollar
WTI	=	West Texas intermediate
WTS	=	West Texas sour

Table of Contents

Basis of Consolidation and Presentation

The accompanying condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2010 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed 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. These reclassifications do not affect net income attributable to Plains or total partners capital. The condensed balance sheet data as of December 31, 2010 was derived from audited financial statements, but does not include all disclosures required by U.S. GAAP. The results of operations for the three and six months ended June 30, 2011 should not be taken as indicative of the results to be expected for the full year.

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

Revision of Prior Period Consolidated Statement of Cash Flows

During the second quarter of 2010, PNG completed its IPO of 13.5 million common units representing limited partner interests. Net proceeds received by PNG from the sale of the common units of approximately $268 million were presented in our financial statements for the quarter ended June 30, 2010 as cash flows from investing activities. Upon further evaluation, we now believe that this activity should have been presented as cash flows from financing activities. We have determined that the impact of this reclassification on our consolidated statement of cash flows for the six months ended June 30, 2010 is not material.

The following captions within the prior period consolidated statement of cash flows were impacted (in millions):

	Amounts Previously Reported	As Revised
Net cash used in investing activities	$ (110)	$ (378)
Net cash provided by/(used in) financing activities	$ (182)	$ 86

Note 2 Recent Accounting Pronouncements

Other than as discussed below and in our 2010 Annual Report on Form 10-K, no new accounting pronouncements have become effective during the six months ended June 30, 2011 that are of significance or potential significance to us.

In December 2010, the FASB issued updated accounting guidance related to the calculation of the carrying amount of a reporting unit when performing the first step of a goodwill impairment test. More specifically, this update will require an entity to use an equity premise when performing the first step of a goodwill impairment test, and if a reporting unit has a zero or negative carrying amount, the entity must assess and consider qualitative factors to determine whether it is more likely than not that a goodwill impairment exists. The new accounting guidance is effective for impairment tests performed during fiscal years (and interim periods within those years) that begin after December 15, 2010. We adopted this guidance on January 1, 2011; however, as we currently do not have any reporting units with a zero or negative carrying amount, our adoption of this guidance did not have a material impact on our financial position, results of operations or cash flows.

In December 2010, the FASB issued updated accounting guidance to clarify that pro forma disclosures should be presented as if a business combination that is determined to be material on an individual or aggregate basis occurred at the beginning of the prior annual period for purposes of preparing both the current reporting period and the prior reporting period pro forma financial information. These disclosures should be accompanied by a narrative description about the nature and amount of material, nonrecurring pro forma adjustments. The new accounting guidance is effective for business combinations consummated in periods beginning after December 15, 2010 and should be applied prospectively as of the date of adoption. We adopted this guidance on January 1, 2011. Our adoption did not have a material impact on our financial position, results of operations or cash flows.

Table of Contents

In January 2010, the FASB issued guidance to enhance disclosures related to the existing fair value hierarchy disclosure requirements. The fair value hierarchy consists of designation to one of three levels based on the nature of the inputs used in the valuation process. Level 1 measurements generally reflect quoted market prices in active markets for identical assets or liabilities, level 2 measurements generally reflect the use of significant observable inputs and level 3 measurements typically utilize significant unobservable inputs. This new guidance requires a gross presentation of activities within the level 3 rollforward. This guidance was effective for annual and interim reporting periods beginning after December 15, 2010. We adopted this guidance on January 1, 2011. See Note 12 for additional disclosure. Our adoption did not have any material impact on our financial position, results of operations, or cash flows.

Accounting Pronouncements Not Yet Effective

In June 2011, the FASB issued new guidance regarding the presentation of comprehensive income. This guidance requires entities to present reclassification adjustments for items that are reclassified from other comprehensive income to net income in the statement in which the components of net income and components of other comprehensive income are presented. It also eliminates the current option under U.S. GAAP to present components of other comprehensive income within the statement of changes in stockholders equity. The components of comprehensive income will be required to be presented within either (i) a single continuous statement of comprehensive income or (ii) two separate but consecutive statements. This guidance is effective for interim and annual periods beginning after December 15, 2011, with earlier adoption permitted. Since this issuance only impacts the presentation of such financial information, adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

In May 2011, the FASB issued guidance to amend certain measurement and disclosure requirements related to fair value in an effort to improve consistency with international reporting standards. This guidance is effective prospectively for interim and annual reporting periods beginning after December 15, 2011. Early adoption is not permitted. The adoption of this guidance is not expected to have a material impact on our financial position, results of operations or cash flows.

Note 3 Trade 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 June 30, 2011 and December 31, 2010, substantially all of our accounts receivable (net of allowance for doubtful accounts) were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled approximately $6 million and $5 million at June 30, 2011 and December 31, 2010, respectively. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

At June 30, 2011 and December 31, 2010, we had received approximately $190 million and $197 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 part of our transactions and also serve to mitigate credit risk.

Note 4 Acquisitions

The following acquisition was accounted for using the acquisition method of accounting, and the purchase price was allocated in accordance with such method.

Southern Pines Acquisition

On February 9, 2011, PNG acquired 100% of the equity interests in SG Resources from SGR Holdings, L.L.C. (the Southern Pines Acquisition) for an aggregate purchase price of approximately $752 million in cash, net of cash acquired, which is subject to finalization of certain post-closing adjustments. The primary asset of SG Resources is the Southern Pines Energy Center (Southern Pines), a FERC-regulated, salt-cavern natural gas storage facility located in Greene County, Mississippi. In connection with this acquisition, PNG obtained financing through a private placement of PNG common units to third-party purchasers, and we purchased additional PNG common units. See Note 10 for further discussion.

Table of Contents

The purchase price allocation related to the Southern Pines Acquisition is preliminary and subject to change, pending completion of internal valuation procedures primarily related to the valuation of intangible assets and the various components of the property and equipment acquired. The preliminary allocation of fair value to intangible assets below is comprised of a tax abatement valued at approximately $15 million and contracts valued at approximately $77 million, which have lives ranging from 2 to 10 years. Amortization of customer contracts under the declining balance method of amortization is estimated to be approximately $13 million, $14 million, $13 million, $11 million and $8 million for the five full or partial calendar years following the acquisition date, respectively. Goodwill or indefinite lived intangible assets will not be subject to depreciation or amortization, but will be subject to periodic impairment testing and, if necessary, will be written down to fair value should circumstances warrant. We expect to finalize our purchase price allocation during 2011. The preliminary purchase price allocation is as follows (in millions):

Description		**Amount**	**Average Depreciable Life (in years)**
Inventory	$	14	N/A
Property and equipment, net		341	5 - 70
Base gas		3	N/A
Other working capital, net of cash acquired		1	N/A
Intangible assets		92	2 - 10
Goodwill		301	N/A
Total	$	752	

Several factors contributed to a purchase price in excess of the fair value of the net tangible and intangible assets acquired. Such factors include the strategic location of the Southern Pines facility, the limited alternative locations and the extended lead times required to develop and construct such facility, along with its operational flexibility, organic expansion capabilities and synergies anticipated to be obtained from combining Southern Pines with our existing asset base. Through June 30, 2011, we have incurred approximately $4 million of acquisition-related costs, which are included in general and administrative expenses in our condensed consolidated statement of operations. This acquisition is reflected within our facilities segment.

In May 2011, PNG entered into an agreement with the former owners of SG Resources with respect to certain outstanding issues and purchase price adjustments as well as the distribution of the remaining 5% of the purchase price that was escrowed at closing (totaling $37 million). Pursuant to this agreement, PNG received approximately $10 million and the balance was remitted to the former owners. Funds received by PNG will be used to fund anticipated facility development and other related costs identified subsequent to closing. Additionally, the parties executed releases of any existing and future claims, subject to customary carve-outs.

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):

	June 30, 2011				December 31, 2010			
	Volumes	Unit of Measure	Total Value	Price/ Unit (1)	Volumes	Unit of Measure	Total Value	Price/ Unit (1)
Inventory								
Crude oil	11,581	barrels	$ 1,108	$ 95.67	14,132	barrels	$ 1,100	$ 77.84
LPG	5,077	barrels	326	$ 64.21	7,395	barrels	366	$ 49.49
Natural gas (2)	3,006	Mcf	13	$ 4.32	13	Mcf		$ 3.87
Other	N/A		5	N/A	N/A		25	N/A
Inventory subtotal			1,452				1,491	
Linefill and base gas								
Crude oil	9,227	barrels	504	$ 54.62	9,159	barrels	478	$ 52.19
Natural gas (2)	12,425	Mcf	42	$ 3.38	11,194	Mcf	37	$ 3.31
LPG	56	barrels	3	$ 53.57	77	barrels	4	$ 51.95
Linefill and base gas subtotal			549				519	
Long-term inventory								
Crude oil	1,727	barrels	128	$ 74.12	1,761	barrels	128	$ 72.69
LPG	150	barrels	8	$ 53.33	505	barrels	26	$ 51.49
Long-term inventory subtotal			136				154	
Total			$ 2,137				$ 2,164	

(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, 2010	$ 640	$ 308	$ 428	$ 1,376
2011 Goodwill Related Activity:				
Southern Pines Acquisition (2)		301		301
Purchase accounting adjustments (2)			10	10
Foreign currency translation adjustments	7		1	8
Other			(3)	(3)
Balance, June 30, 2011	$ 647	$ 609	$ 436	$ 1,692

(1) As of June 30, 2011, we do not have any material accumulated impairment losses.

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

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

Table of Contents

Note 7 Debt

Debt consisted of the following (in millions):

	June 30, 2011	December 31, 2010
SHORT-TERM DEBT		
Credit Facilities:		
Senior secured hedged inventory facility bearing a weighted-average interest rate of 2.1% for both periods presented	$ 300	$ 500
PAA senior unsecured revolving credit facility, bearing a weighted-average interest rate of 1.1% and 0.7% at June 30, 2011 and December 31, 2010, respectively (1)	234	824
Other	2	2
Total short-term debt	536	1,326
LONG-TERM DEBT		
Senior Notes:		
4.25% senior notes due September 2012 (2)	500	500
7.75% senior notes due October 2012 (3)		200
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 (4)	600	
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized discounts	(14)	(12)
Senior notes, net of unamortized discounts	4,761	4,363
Credit Facilities and Other:		
PNG senior unsecured revolving credit facility, bearing a weighted-average interest rate of 2.9% and 3.2% at June 30, 2011 and December 31, 2010, respectively	226	260
Other	8	8
Total long-term debt (1)	4,995	4,631
Total debt (5)	$ 5,531	$ 5,957

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(1) We classify as short-term any borrowings under our PAA senior unsecured revolving credit facility. These borrowings are designated as working capital borrowings, must be repaid within one year and are primarily for hedged LPG and crude oil inventory and NYMEX and ICE margin deposits.

(2) The proceeds from these notes are being used to supplement capital available from our hedged inventory facility. At June 30, 2011 and December 31, 2010, approximately $500 million and $466 million, respectively, had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

(3) On February 7, 2011, our $200 million, 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million, recorded to Other income/(expense), net in our condensed consolidated statement of operations. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

(4) In January 2011, we completed the issuance of $600 million, 5.00% senior notes due 2021. The senior notes were sold at 99.521% of face value. Interest payments are due on February 1 and August 1 of each year, beginning on August 1, 2011. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities and for general partnership purposes.

Table of Contents

(5) Our fixed-rate senior notes have a face value of approximately $4.8 billion and $4.4 billion as of June 30, 2011 and December 31, 2010, respectively. We estimate the aggregate fair value of these notes as of June 30, 2011 and December 31, 2010 to be approximately $5.2 billion and $4.7 billion, respectively. Our fixed-rate senior notes are traded among institutions, which 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.

PAA 364-Day Credit Facility

In January 2011, we entered into a 364-day senior unsecured credit facility with an aggregate borrowing capacity of $500 million. This credit facility has a maximum debt-to-EBITDA coverage ratio of 4.75 to 1.00 (5.50 to 1.00 during an acquisition period) and matures at the earlier of January 2012 or the refinancing of our PAA senior unsecured revolving credit facility. As set forth in the agreement, borrowings under this facility bear interest at our election at either LIBOR plus an applicable margin (based on the credit rating of our long-term senior unsecured debt), or a base rate. Commitment fees are payable at rates between 0.15% and 0.40%, also determined based on the credit rating of our long-term senior unsecured debt. Borrowings may be used for any partnership purpose. There were no outstanding borrowings under this facility at June 30, 2011.

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 June 30, 2011 and December 31, 2010, we had outstanding letters of credit of approximately $95 million and $75 million, respectively.

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 and six months ended June 30, 2011 and 2010 (amounts in millions, except per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2011	**2010**	**2011**	**2010**
Numerator for basic and diluted earnings per limited partner unit:				
Net income attributable to Plains	$ 225	$ 131	$ 408	$ 282
Less: General partner s incentive distribution paid (1)	(50)	(39)	(97)	(77)
Subtotal	175	92	311	205
Less: General partner 2% ownership (1)	(4)	(2)	(6)	(4)
Net income available to limited partners	171	90	305	201
Adjustment in accordance with application of the two-class method for MLPs (1)	(1)	(1)	(6)	(3)

Net income available to limited partners in accordance with the application of the two-class method for MLPs	$	170	$	89	$	299	$	198
Denominator:								
Basic weighted average number of limited partner units outstanding		149		136		146		136
Effect of dilutive securities:								
Weighted average LTIP units (2)		1		1		1		1
Diluted weighted average number of limited partner units outstanding		150		137		147		137
Basic net income per limited partner unit	$	1.14	$	0.65	$	2.04	$	1.45
Diluted net income per limited partner unit	$	1.13	$	0.65	$	2.03	$	1.45

Table of Contents

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(1) We calculate net income available to limited partners based on the distribution paid during the current quarter (including the incentive distribution interest in excess of the 2% general partner interest). However, FASB guidance requires that the distribution pertaining to the current period s net income, which is to be paid in the subsequent quarter, be utilized in the earnings per unit calculation. After adjusting for this distribution, 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 for earnings per unit calculation purposes. We reflect the impact of the difference in (i) the distribution utilized and (ii) the calculation of the excess 2% general partner interest as the Adjustment in accordance with application of the two-class method for MLPs.

(2) Our LTIP awards (described in Note 11) 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.

Note 9 Income Taxes

U.S. Federal and State Taxes

As an MLP, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. Although we are subject to state income taxes in some states, the impact to the three and six months ended June 30, 2011 and 2010 was immaterial.

Canadian Federal and Provincial Taxes

In 2010 and prior years, our Canadian operations were operated through a combination of corporate entities subject to Canadian federal and provincial taxes and a limited partnership which was treated as a flow-through entity for tax purposes. Due to changes in Canadian legislation and the Fifth Protocol to the U.S./Canada Tax Treaty, we restructured our Canadian investment on January 1, 2011. As of this date, all of our Canadian operations are conducted within entities that are treated as corporations for Canadian tax purposes (flow through for U.S. tax purposes) and that are subject to Canadian federal and provincial taxes. Additionally, payments of interest and dividends from Canada to other Plains entities are subject to Canadian withholding tax that is treated as a distribution to unitholders.

Note 10 Partners Capital and Distributions

Noncontrolling Interests in a Subsidiary

As of June 30, 2011, noncontrolling interests consisted of the following: (i) an approximate 36% interest in PNG and (ii) a 25% interest in SLC Pipeline LLC.

During February 2011, in connection with the Southern Pines Acquisition, PNG completed a private placement of approximately 17.4 million PNG common units to third-party purchasers for net proceeds of approximately $370 million. In addition, we purchased approximately 10.2 million PNG common units for approximately $230 million, including our proportionate general partner contribution of $12 million (collectively, the PNG offering). Also, during May 2011, a portion of the PNG Transaction Grants vested and were settled with 58,672 PNG units, which were owned by us. See Note 10 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for further detail regarding the *PNG Transaction Grants*. As a result of these transactions, our aggregate ownership interest in PNG decreased from approximately 77% to approximately 64%. The following table sets forth our ownership changes in the limited partner units of PNG from December 31, 2010 to June 30, 2011 (units in millions):

	December 31, 2010	February 2011 PNG Issuance	Transaction Grants	June 30, 2011
PNG Units Owned by PAA:				
Common Units	18.1	10.2	(0.1)	28.2
Series A Subordinated Units	11.9			11.9
Series B Subordinated Units	13.5			13.5
Total PNG Units Owned by PAA	43.5	10.2	(0.1)	53.6

Table of Contents

In addition to our limited partner interest, we also own the general partner s 2% interest and the incentive distribution rights in PNG.

In conjunction with the PNG offering, we recorded an increase in noncontrolling interest of $306 million and an increase to our partners capital of approximately $64 million. The increases result from the portion of the proceeds attributable to the respective ownership interests in PNG, adjusted for the impact of the dilution of our ownership interest resulting from this transaction.

The following table sets forth the impact of the changes in our ownership interest in PNG on our capital (in millions):

	For the Six Months Ended June 30, 2011		For the Six Months Ended June 30, 2010	
Net income attributable to Plains	$	408	$	282
Transfers to the noncontrolling interests:				
Increase in capital from sale of PNG units		64		101
Change from net income attributable to Plains and net transfers to the noncontrolling interest	$	472	$	383

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

	For the Six Months Ended June 30, 2011		For the Six Months Ended June 30, 2010	
Beginning balance	$	231	$	63
Sale of noncontrolling interests in a subsidiary		306		167
Net income attributable to noncontrolling interests		10		2
Distributions to noncontrolling interests		(16)		(1)
Equity compensation expense		2		
Ending Balance	$	533	$	231

PAA Distributions

The following table details the distributions paid during or pertaining to the first six months of 2011, net of reductions to the general partner s incentive distributions (in millions, except per unit amounts):

Date Declared	Date Paid or To Be Paid		Distributions Paid Common Units		Distributions Paid General Partner Incentive		Distributions Paid General Partner 2%		Total		Distributions per limited partner unit
July 11, 2011	August 12, 2011 (1)	$	147	$	52	$	3	$	202	$	0.9825
April 11, 2011	May 13, 2011	$	145	$	50	$	3	$	198	$	0.9700
January 12, 2011	February 14, 2011	$	135	$	46	$	3	$	184	$	0.9575

(1) Payable to unitholders of record at the close of business on August 2, 2011, for the period April 1, 2011 through June 30, 2011.

In conjunction with the closing of certain acquisitions, our general partner agreed to temporarily reduce the amounts due it as incentive distributions. Following the distribution in August 2011, the aggregate incentive distribution reductions remaining will be approximately $1 million. See Note 5 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for further detail regarding our *General Partner Incentive Distributions*.

Table of Contents

PAA Equity Offerings

During the six months ended June 30, 2011, we completed an equity offering of our common units as shown in the table below (in millions, except per unit data):

Date	Units Issued		Gross Unit Price		Proceeds from Sale		General Partner Contribution		Costs		Net Proceeds
March 2011 (1)	7,935,000	$	64.00	$	508	$	10	$	(15)	$	503

(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 reduce outstanding borrowings under our credit facilities and for general partnership purposes.

Note 11 Equity Compensation Plans

For discussion of our equity compensation awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K.

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

	PAA Units			PNG Units		
	Units		Weighted Average Grant Date Fair Value per Unit	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding, December 31, 2010	4.4	$	41.69	1.0	$	20.55
Granted	0.3	$	54.50		$	
Vested	(0.6)	$	40.88	(0.1)	$	23.67
Cancelled or forfeited	(0.1)	$	41.56		$	
Outstanding, June 30, 2011	4.0	$	43.06	0.9	$	20.41

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 June 30,		Six Months Ended June 30,	
	2011	2010	2011	2010

Equity compensation expense	$	27	$	14	$	46	$	33
LTIP unit vestings (1)	$	23	$	25	$	23	$	25
LTIP cash settled vestings	$	18	$	10	$	18	$	10
DER cash payments	$	1	$	1	$	2	$	2

(1) For the three and six months ended June 30, 2011, approximately $1 million relates to unit vestings which were settled with PNG units.

Note 12 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 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 and strategies for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument s effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Commodity Price Risk Hedging

Our core business activities contain certain commodity price-related risks that we manage in various ways, including the use of derivative instruments. Our policy is (i) to only purchase 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 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 June 30, 2011, net derivative positions related to these activities included:

- An approximate 212,900 barrels per day net long position (total of 6.4 million barrels) associated with our crude oil purchases, which was unwound ratably during July 2011 to match monthly average pricing.

- A net short spread position averaging approximately 39,300 barrels per day (total of 21.5 million barrels), which hedges a portion of our anticipated crude oil lease gathering purchases through January 2013. These derivatives also hedge the margin associated with anticipated crude oil purchases. These derivatives are time spreads consisting of offsetting purchases and sales between two different months, and other than for changes in the spreads, do not result in exposure to outright price movements.

- A net short calender spread call options position averaging approximately 32,200 barrels per day (total of 5.9 million barrels) for the period August 2011 through January 2012. These derivatives also hedge the margin associated with anticipated crude oil purchases. These derivatives are time spreads between two different months, and other than for changes in the spreads, do not result in exposure to outright price movements.

- Approximately 5,400 barrels per day on average (total of 2.9 million barrels) of WTS/WTI crude oil basis swaps through December 2012, which hedge anticipated sales of crude oil (WTI). These derivatives are grade spreads between two different grades of crude oil, and other than for changes in the spreads, do not result in exposure to outright price movements.

- Approximately 3,100 barrels per day on average (total of 0.9 million barrels) of butane/WTI spread positions, which hedge specific butane sales contracts that are priced as a fixed percentage of WTI and continue through March 2012. These derivatives are cross-commodity spreads between butane and WTI, and other than for changes in the spreads, do not result in exposure to outright price movements.

Storage Capacity Utilization We own approximately 70 million barrels of crude oil, LPG and refined products storage capacity other than that used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations, we have utilization risk if the market structure is backwardated. As of June 30, 2011, we used derivatives to manage the risk of not utilizing approximately 3.8 million barrels per month of storage capacity through 2012. These positions are a combination of calendar spread options and futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage At times, we elect to purchase and store crude oil, LPG 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 June 30, 2011, we had derivatives totaling approximately 9.4 million barrels hedging our inventory. These positions are a combination of swaps and futures contracts.

We also purchase waterborne cargos of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of crude inventory. As of June 30, 2011, we had approximately 0.5 million barrels of crude oil derivatives hedging the anticipated sale of such crude inventory.

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 June 30, 2011, our PLA hedges included (i) a net short position consisting of crude oil futures and swaps for an average of approximately 1,700 barrels per day (total of 2.9 million barrels) through December 2015, (ii) a long put option position of

Table of Contents

approximately 0.4 million barrels through December 2012 and (iii) a long call option position of approximately 0.4 million barrels through December 2012.

Natural Gas Purchases and Sales Our gas storage facilities require minimum levels of natural gas (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 June 30, 2011, we have a long futures position of approximately 0.7 Bcf, 3.0 Bcf of long swaps, and a long call option position of approximately 0.7 Bcf related to anticipated base gas purchases. Additionally, our natural gas commercial marketing group captures short-term market opportunities by leasing a portion of our owned or leased storage capacity to engage in related commercial marketing activities. We use various derivatives, including index and basis swaps, to hedge anticipated purchases and sales of natural gas by our commercial marketing group. As of June 30, 2011, we have a short swap position of approximately 6.6 Bcf related to anticipated sales of natural gas, and an approximate 6.3 Bcf long swap position related to anticipated purchases of natural gas. Additionally, we have a net short calendar spread call option position of approximately 3.0 Bcf related to anticipated sales of natural gas. These calls in the aggregate do not result in exposure to outright price movements.

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 June 30, 2011, AOCI includes deferred gains of $9 million that relate to open and terminated interest rate swaps and treasury locks 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 original terms of the hedged debt instruments.

During June and July 2011, we entered into six forward starting interest rate swaps to hedge the underlying benchmark interest rate related to forecasted debt issuances through 2013. The following table summarizes the terms of our forward starting interest rate swaps (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	3 forward starting swaps (30-year)	$ 150	6/17/2013	4.35%	Cash flow hedge
Anticipated debt offering	3 forward starting swaps (10-year)	$ 150	6/15/2012	3.53%	Cash flow hedge

During June 2011, PNG entered into two interest rate swaps to fix the interest rate on a portion of its revolving credit facility. The swaps have an aggregate notional amount of $50 million with an average fixed rate of 1.06% and terminate in June 2014.

Concurrent with our January 2011 senior notes issuance, we terminated three forward starting interest rate swaps. See Note 7 for additional disclosure. These swaps had an aggregate notional amount of $100 million and an average fixed rate of 3.6%. We received cash proceeds of $12 million associated with the termination of these swaps.

During July 2009, 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 terminate in September 2011 and two of the swaps terminate in September 2012. The swaps that terminate in 2012 are designated as fair value hedges.

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use foreign currency derivatives to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of June 30, 2011, AOCI includes net deferred gains of $11

Table of Contents

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 a CAD-denominated intercompany note as a result of changes in the exchange rate.

As of June 30, 2011, 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
2011 (1)	$ 58	$ 59	CAD $0.97 to US $1.00
2012	$ 15	$ 15	CAD $1.01 to US $1.00
2013	$ 9	$ 9	CAD $1.00 to US $1.00

(1) Includes $50 million of forward exchange contracts that we entered into during July 2011.

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 consolidated statements of cash flows.

Table of Contents

A summary of the impact of our derivative activities recognized in earnings for the three and six months ended June 30, 2011 and 2010 is as follows (in millions):

	Three Months Ended June 30, 2011			Three Months Ended June 30, 2010		
Location of gain/(loss)	**Derivatives in Hedging Relationships (1)(2)**	**Derivatives Not Designated as a Hedge (4)**	**Total**	**Derivatives in Hedging Relationships (1)(2)**	**Derivatives Not Designated as a Hedge (4)**	**Total**
Commodity Derivatives						
Supply and Logistics segment revenues	$ (161)	$ 36	$ (125)	$ (6)	$ 28	$ 22
Facilities segment revenues	(6)	1	(5)			
Purchases and related costs		(1)	(1)	(8)	11	3
Interest Rate Derivatives						
Interest expense					1	1
Foreign Currency Derivatives						
Supply and Logistics segment revenues					(3)	(3)
Other income, net	1		1		1	1
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ (166)**	**$ 36**	**$ (130)**	**$ (14)**	**$ 38**	**$ 24**

Table of Contents

Location of gain/(loss)	Six Months Ended June 30, 2011 Derivatives in Hedging Relationships (1)(2)(3)	Six Months Ended June 30, 2011 Derivatives Not Designated as a Hedge (4)	Six Months Ended June 30, 2011 Total	Six Months Ended June 30, 2010 Derivatives in Hedging Relationships (1)(2)	Six Months Ended June 30, 2010 Derivatives Not Designated as a Hedge (4)	Six Months Ended June 30, 2010 Total
Commodity Derivatives						
Supply and Logistics segment revenues	$ (236)	$ 40	$ (196)	$ (26)	$ 55	$ 29
Transportation segment revenues				1		1
Facilities segment revenues	(7)	1	(6)	(1)	1	
Purchases and related costs		(1)	(1)	(3)	(13)	(16)
Field operating costs		1	1			
Interest Rate Derivatives						
Interest expense	1		1		2	2
Foreign Currency Derivatives						
Supply and Logistics segment revenues		3	3		(3)	(3)
Purchases and related costs					2	2
Other income, net	2		2			
Total Gain/(Loss) on Derivatives Recognized in Net Income	**$ (240)**	**$ 44**	**$ (196)**	**$ (29)**	**$ 44**	**$ 15**

(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 gains of approximately $1 million for the three months ended June 30, 2010 and losses of approximately $8 million for the six months ended June 30, 2011 that represent the ineffective portion of our cash flow hedges. These amounts relate to commodity derivatives and are recognized in Supply and Logistics segment revenues during such periods.

(3) Interest expense includes a net gain of approximately $1 million for the six months ended June 30, 2011 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.

Table of Contents

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of June 30, 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	$	97	Other current assets	$	(90)
	Other long-term assets		7	Other long-term assets		(1)
Interest rate derivatives	Other current assets		5			
	Other long-term assets		2			
Foreign currency derivatives				Other current liabilities		(1)
Total derivatives designated as hedging instruments		$	111		$	(92)
Derivatives not designated as hedging instruments:						
Commodity derivatives	Other current assets	$	128	Other current assets	$	(114)
	Other long-term assets		8	Other long-term assets		(9)
				Other current liabilities		(4)
Foreign currency derivatives	Other current assets		1			
Total derivatives not designated as hedging instruments		$	137		$	(127)
Total derivatives		$	248		$	(219)

Table of Contents

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2010 (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	$ 71	Other current assets	$ (70)
			Other long-term assets	(1)
			Other current liabilities	(1)
Interest rate derivatives	Other current assets	10		
Total derivatives designated as hedging instruments		$ 81		$ (72)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 11	Other current assets	$ (68)
	Other long-term assets	20		
	Other current liabilities	2	Other current liabilities	(10)
Interest rate derivatives	Other current assets	4		
	Other long-term assets	1		
Foreign currency derivatives	Other current assets	1		
Total derivatives not designated as hedging instruments		$ 39		$ (78)
Total derivatives		$ 120		$ (150)

As of June 30, 2011, there was a net gain of $59 million deferred in AOCI. The total amount of deferred net gain 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 gain deferred in AOCI at June 30, 2011, we expect to reclassify a net gain of approximately $41 million to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately $13 million is expected to be reclassified to earnings prior to 2014 with the remaining deferred gain being reclassified to earnings through 2041. These amounts are predominately 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 and six months ended June 30, 2011, we reclassified a gain of approximately $1 million from AOCI to facilities segment revenues as a result of anticipated hedged transactions that are no longer considered to be probable of occurring. During the three and six months ended June 30, 2010, all of our hedged transactions were probable of occurring. The net deferred gain/(loss), excluding tax effects, recognized in AOCI for derivatives during the three and six months ended June 30, 2011 and 2010 are as follows (in millions):

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2011	2010	2011	2010

Commodity derivatives	$ 48	$ 18	$ (97)	$ 14
Foreign currency derivatives			(1)	(1)
Interest rate derivatives	4	1	6	1
Total	$ 52	$ 19	$ (92)	$ 14

Table of Contents

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 June 30, 2011, we had a net broker receivable of approximately $33 million (consisting of initial margin of $65 million reduced by $32 million of variation margin that had been returned to us). As of December 31, 2010, we had a net broker receivable of approximately $99 million (consisting of initial margin of $56 million increased by $43 million of variation margin that had been posted by us). At June 30, 2011 and December 31, 2010, 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.

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 June 30, 2011 and December 31, 2010. 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 June 30, 2011 (in millions)				Fair Value as of December 31, 2010 (in millions)			
Recurring Fair Value Measures (1)	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Commodity derivatives	$ 12	$	$ 10	$ 22	$ (16)	$	$ (30)	$ (46)
Interest rate derivatives		7		7			15	15
Foreign currency derivatives							1	1
Total	$ 12	$ 7	$ 10	$ 29	$ (16)	$	$ (14)	$ (30)

(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. We measure credit risk by deriving a probability of default from market-observed credit default swap spreads as of the measurement date. The probability of default is applied to the net credit exposure of each of our counterparties and includes a recovery rate adjustment. The recovery rate is an estimate of what would ultimately be recovered through a bankruptcy proceeding in the event of default. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are 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 and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy are interest rate derivatives that include interest rate swaps. The fair value of these interest rate derivatives is based on broker or dealer price quotations which are corroborated with market observable inputs including forward interest rates obtained from pricing services.

Level 3

Included within level 3 of the fair value hierarchy are 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 inputs such as forward prices but do not involve significant management judgments.

Table of Contents

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 June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Beginning Balance	$ (5)	$ (5)	$ (14)	$ (28)
Unrealized gains/(losses):				
Included in earnings (1)	7	5	13	12
Included in other comprehensive income	1	1	(1)	1
Settlements	1	6	33	27
Derivatives entered into during the period	6	1	(4)	(4)
Transfers out of level 3			(17)	
Ending Balance	$ 10	$ 8	$ 10	$ 8
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the period	$ 13	$ 10	$ 11	$ 9

(1) We reported unrealized gains and losses associated with level 3 commodity derivatives in our consolidated statements of operations as Supply and Logistics segment revenues. Gains and losses associated with interest rate derivatives are reported in our consolidated statements of operations as Interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either Supply and Logistics segment revenues, Purchases and related costs, or Other income, net.

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.

Note 13 Commitments and Contingencies

Litigation

SemCrude L.P., et al Debtors/Associated Producers/Orange Creek Energy (U.S. Bankruptcy Court Delaware). We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude, which commenced in July 2008. Statutory protections and our contractual rights of setoff covered substantially all of our pre-petition claims against SemCrude and such claims have now been resolved. In separate actions certain creditors of SemCrude have also filed state court actions alleging a producer s lien on crude oil sold to SemCrude and its affiliates, and the continuation of such lien when SemCrude and its affiliates subsequently sold the oil to purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. Fourteen state court actions have been consolidated in Bankruptcy Court. One action is in Federal Court in Texas. We intend to vigorously defend our contractual and statutory rights.

ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and involves the allocation of responsibility for remediation of MTBE and other petroleum product contamination at the terminal facility in Paulsboro, New Jersey operated by Plains Product Terminals LLC (formerly Pacific Atlantic Terminals LLC) (PPT), which we acquired in the Pacific merger. Both ExxonMobil and GATX were prior owners of the terminal. We have entered into a Settlement Agreement with the State of New Jersey and Kinder Morgan (as successor in interest to GATX), which requires PPT and Kinder Morgan to install and implement an MTBE environmental restoration and monitoring program. We estimate the cost to Plains for this program will be approximately $2.5 million, which amount may be higher or lower depending on the nature and extent of the cleanup. Court approval of the settlement is pending.

Table of Contents

New Jersey Department of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, ExxonMobil and PPT to recover natural resources damages associated with, and to require remediation of, the contamination at our Paulsboro terminal facility. ExxonMobil and GATX have filed third-party demands against PPT, seeking indemnity and contribution. The natural resources damages have been settled and set at $1.1 million payable to the State of New Jersey. PPT s allocated share of this liability is $550,000. Court approval of the settlement is pending.

EPA v. Rocky Mountain Pipeline System. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of RMPS, a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. After responding to the request, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the Clean Air Act related to registration, sampling, recording and reporting in connection with such activities. EPA further alleged that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA referred the matter to the DOJ. Settlement discussions resulted in a Consent Decree effective as of July 12, 2011. The Decree includes provision for a penalty of $2.5 million and a commitment to an environmental project at an estimated cost of $250,000.

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 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.

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 spend 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 June 30, 2011, our reserve for environmental liabilities, including the reserve related to our Rainbow Pipeline release as discussed further below, totaled approximately $122 million, of which approximately $64 million was classified as short-term and $58 million was classified as long-term. At December 31, 2010, our reserve for environmental liabilities totaled approximately $66 million, of which approximately $10 million was classified as short-term and $56 million was classified as long-term. At June 30, 2011 and December 31, 2010, we had recorded receivables totaling approximately $64 million and $5 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

Rainbow Pipeline Release

On April 29, 2011, we experienced a crude oil release on a remote section of our Rainbow Pipeline located in Alberta, Canada. Upon detection of the release, approximately 45 miles of the pipeline were isolated and depressurized and emergency response personnel were mobilized to conduct clean-up operations in cooperation with the Alberta Energy Resources Conservation Board (ERCB). We currently estimate that approximately 28,000 barrels of crude oil were released, which affected a site of approximately 40 acres located primarily on the pipeline right-of-way. Although clean-up operations and contamination monitoring continue, we completed the pipeline repair and have completed additional regulatory requested pipeline inspections and information requests and await regulatory approval to restart the north section of the pipeline.

We estimate that the aggregate total cost to clean-up and remediate the site, before insurance recoveries, is $72 million. This estimate considers our prior experience in environmental investigation and remediation matters, as well as available data from, and in consultation with, our environmental specialists. This estimate is subject to uncertainties caused by the dynamic nature of site conditions, the range of remediation alternatives available and the corresponding costs of various clean-up methodologies. Accordingly, it is likely that adjustments to this liability estimate may be necessary as further information and circumstances regarding the site characterization develop. Also, we currently are awaiting approval from regulatory agencies regarding certain portions of our remediation plan, which will determine the nature of the remaining remediation efforts. The outcome of the regulatory agencies review, along with various other factors such as adverse weather and temperature changes, could escalate our total cost. Although actual remediation costs may be more than amounts accrued, we believe we have established adequate reserves for all probable and reasonably estimable costs. We currently expect that the clean-up and remediation efforts, excluding long-term site monitoring activities, will be substantially completed by the first quarter of 2012. We have accrued the total estimated costs to operating expense on our condensed consolidated income statement. As of June 30, 2011, we have a remaining undiscounted gross environmental remediation liability of $58 million. This liability is presented as a current liability within the caption Accounts payable and accrued liabilities on our condensed consolidated balance sheet. We maintain insurance coverage, which is subject to certain exclusions and deductibles, to protect us against such environmental liabilities. This coverage is adequate to cover the current estimated total remediation costs, and management believes that this coverage is also adequate to cover any potential remediation costs that may be in excess of amounts currently identified. We therefore have recognized a receivable of $59 million as of June 30, 2011 for the portion of this liability that we believe is probable of recovery from insurance, net of deductibles. This receivable has been recognized as a current asset within the caption Trade accounts receivable and other receivables, net on our condensed consolidated balance sheet with the offset reducing operating expense on our condensed consolidated income statement.

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. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at 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 for the 2010 renewal totaling 20% or more of the coverage limit.

For the last two years we have purchased a hurricane limit of $10 million to cover property and business interruption, representing substantially the level of insurance that was available. The coverage provided by these policies contained much stricter limitations than the insurance policies available prior to hurricanes Rita and Katrina. As a result of these conditions, we have decided not to purchase this coverage for 2011/12 and will self-insure this risk. This decision does not affect our third-party liability insurance, which still covers hurricane-related liability claims, and we expect to renew our liability insurance tower 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.

Table of Contents

Note 14 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 & Logistics	Total
Three Months Ended June 30, 2011				
Revenues:				
External Customers	$ 147	$ 126	$ 8,586	$ 8,859
Intersegment (1)	143	38		181
Total revenues of reportable segments	$ 290	$ 164	$ 8,586	$ 9,040
Equity earnings in unconsolidated entities	$ 4	$	$	$ 4
Segment profit (2) (3)	$ 128	$ 86	$ 151	$ 365
Maintenance capital	$ 17	$ 7	$ 3	$ 27
Three Months Ended June 30, 2010				
Revenues:				
External Customers	$ 139	$ 84	$ 5,901	$ 6,124
Intersegment (1)	120	37		157
Total revenues of reportable segments	$ 259	$ 121	$ 5,901	$ 6,281
Equity earnings in unconsolidated entities	$ 1	$	$	$ 1
Segment profit (2) (3)	$ 130	$ 70	$ 57	$ 257
Maintenance capital	$ 15	$ 5	$ 2	$ 22

	Transportation	Facilities	Supply & Logistics	Total
Six Months Ended June 30, 2011				
Revenues:				
External Customers	$ 288	$ 244	$ 16,021	$ 16,553
Intersegment (1)	276	81	1	358
Total revenues of reportable segments	$ 564	$ 325	$ 16,022	$ 16,911
Equity earnings in unconsolidated entities	$ 5	$	$	$ 5
Segment profit (2) (3)	$ 265	$ 164	$ 285	$ 714
Maintenance capital	$ 35	$ 10	$ 7	$ 52
Six Months Ended June 30, 2010				
Revenues:				
External Customers	$ 277	$ 158	$ 11,813	$ 12,248
Intersegment (1)	232	77	1	310
Total revenues of reportable segments	$ 509	$ 235	$ 11,814	$ 12,558
Equity earnings in unconsolidated entities	$ 2	$	$	$ 2
Segment profit (2) (3)	$ 257	$ 129	$ 150	$ 536
Maintenance capital	$ 22	$ 8	$ 3	$ 33

(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 2010 Annual Report on Form 10-K.

(2) Supply and logistics segment profit includes interest expense (related to hedged inventory purchases) of $7 million and $5 million for the three months ended June 30, 2011 and 2010, respectively, and $12 million and $8 million for the six months ended June 30, 2011 and 2010, respectively.

Table of Contents

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

	For the Three Months Ended June 30, 2011	For the Three Months Ended June 30, 2010	For the Six Months Ended June 30, 2011	For the Six Months Ended June 30, 2010
Segment profit	$ 365	$ 257	$ 714	$ 536
Depreciation and amortization	(63)	(64)	(126)	(131)
Interest expense	(62)	(62)	(128)	(120)
Other income/(expense), net	2	2	(20)	(1)
Income tax expense	(9)		(22)	
Net income	233	133	418	284
Less: Net income attributable to noncontrolling interests	(8)	(2)	(10)	(2)
Net income attributable to Plains	$ 225	$ 131	$ 408	$ 282

Note 15 Related Party Transactions

See Note 9 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for a complete discussion of our related party transactions.

Occidental Petroleum Corporation

As of June 30, 2011, 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 and six months ended June 30, 2011 and 2010, we received sales and transportation storage revenues and purchased petroleum products from companies associated with Oxy. These transactions were consummated on terms equivalent to those that prevail in arm s-length transactions with our other counterparties. See detail below (in millions):

	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010
Total revenues	$ 1,079	$ 500	$ 1,781	$ 693
Purchases and related costs	$ 92	$ 52	$ 165	$ 90

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

	June 30, 2011	December 31, 2010

Trade accounts receivable and other receivables	$	494	$	379
Accounts payable	$	143	$	124

Table of Contents

Note 16 Supplemental Condensed Consolidating Financial Information

For purposes of the following footnote, Plains is referred to as Parent. See Note 13 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for further detail regarding subsidiaries classified as Guarantor Subsidiaries and subsidiaries classified as Non-Guarantor Subsidiaries. There have been no material changes in the entities that constitute our guarantor and non-guarantor subsidiaries since December 31, 2010.

The following supplemental condensed consolidating financial information reflects the Parent s separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent s consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent s investments in its subsidiaries and the Guarantor Subsidiaries investments in their subsidiaries are accounted for under the equity method of accounting (in millions):

Condensed Consolidating Balance Sheets

	As of June 30, 2011				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,941	$ 4,890	$ 469	$ (3,667)	$ 4,633
Property and equipment, net	3	5,053	2,220		7,276
Investments in unconsolidated entities	7,595	1,429		(8,829)	195
Other assets, net	231	3,271	2,074	(2,767)	2,809
Total assets	$ 10,770	$ 14,643	$ 4,763	$ (15,263)	$ 14,913
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 324	$ 6,814	$ 512	$ (3,667)	$ 3,983
Long-term debt	4,763	1,292	1,707	(2,767)	4,995
Other long-term liabilities		249	3		252
Total liabilities	5,087	8,355	2,222	(6,434)	9,230
Partners capital excluding noncontrolling interests	5,150	6,227	2,541	(8,768)	5,150
Noncontrolling interests	533	61		(61)	533
Total partners capital	5,683	6,288	2,541	(8,829)	5,683
Total liabilities and partners capital	$ 10,770	$ 14,643	$ 4,763	$ (15,263)	$ 14,913

Table of Contents

Condensed Consolidating Balance Sheets (continued)

	As of December 31, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,460	$ 4,394	$ 510	$ (3,983)	$ 4,381
Property and equipment, net	2	4,870	1,819		6,691
Investments in unconsolidated entities	6,302	2,173		(8,275)	200
Other assets, net	28	1,976	553	(126)	2,431
Total assets	$ 9,792	$ 13,413	$ 2,882	$ (12,384)	$ 13,703
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 853	$ 6,836	$ 509	$ (3,983)	$ 4,215
Long-term debt	4,366	5	386	(126)	4,631
Other long-term liabilities		270	14		284
Total liabilities	5,219	7,111	909	(4,109)	9,130
Partners capital excluding noncontrolling interests	4,342	6,241	1,973	(8,214)	4,342
Noncontrolling interests	231	61		(61)	231
Total partners capital	4,573	6,302	1,973	(8,275)	4,573
Total liabilities and partners capital	$ 9,792	$ 13,413	$ 2,882	$ (12,384)	$ 13,703

Table of Contents

Condensed Consolidating Statements of Operations

	Three Months Ended June 30, 2011				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 578	$ 79	$	$ 657
Field operating costs		(205)	(18)		(223)
General and administrative expenses		(64)	(9)		(73)
Depreciation and amortization	(1)	(46)	(16)		(63)
Operating income/(loss)	(1)	263	36		298
Equity earnings in unconsolidated entities	297	23		(316)	4
Interest income/(expense)	(65)	2	1		(62)
Other income/(expense), net	2	2	(2)		2
Income tax expense		(9)			(9)
Net income	233	281	35	(316)	233
Less: Net income attributable to noncontrolling interests	(8)	(1)		1	(8)
Net income attributable to Plains	$ 225	$ 280	$ 35	$ (315)	$ 225

	Three Months Ended June 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 428	$ 55	$	$ 483
Field operating costs		(157)	(14)		(171)
General and administrative expenses		(49)	(7)		(56)
Depreciation and amortization	(1)	(51)	(12)		(64)
Operating income/(loss)	(1)	171	22		192
Equity earnings in unconsolidated entities	196	20		(215)	1
Interest income/(expense)	(62)	3	(3)		(62)
Other income/(expense), net		2			2
Income tax expense					
Net income	133	196	19	(215)	133
Less: Net income attributable to noncontrolling interests	(2)				(2)
Net income attributable to Plains	$ 131	$ 196	$ 19	$ (215)	$ 131

Table of Contents

Condensed Consolidating Statements of Operations (continued)

	Six Months Ended June 30, 2011				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 1,113	$ 159	$	$ 1,272
Field operating costs		(377)	(43)		(420)
General and administrative expenses		(120)	(23)		(143)
Depreciation and amortization	(3)	(93)	(30)		(126)
Operating income/(loss)	(3)	523	63		583
Equity earnings in unconsolidated entities	573	40		(608)	5
Interest income/(expense)	(133)	6	(1)		(128)
Other income/(expense), net	(19)	3	(4)		(20)
Income tax expense		(22)			(22)
Net income	$ 418	$ 550	$ 58	$ (608)	$ 418
Less: Net income attributable to noncontrolling interests	(10)	(1)		1	(10)
Net income attributable to Plains	$ 408	$ 549	$ 58	$ (607)	$ 408

	Six Months Ended June 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 881	$ 104	$	$ 985
Field operating costs		(306)	(28)		(334)
General and administrative expenses		(104)	(13)		(117)
Depreciation and amortization	(2)	(106)	(23)		(131)
Operating income/(loss)	(2)	365	40		403
Equity earnings in unconsolidated entities	411	37		(446)	2
Interest income/(expense)	(125)	11	(6)		(120)
Other income/(expense), net		(1)			(1)
Income tax expense					
Net income	$ 284	$ 412	$ 34	$ (446)	$ 284
Less: Net income attributable to noncontrolling interest	(2)	(1)		1	(2)
Net income attributable to Plains	$ 282	$ 411	$ 34	$ (445)	$ 282

(1) Net operating revenues are calculated as Total revenues less Purchases and related costs.

Table of Contents

Condensed Consolidating Statements of Cash Flows

	Six Months Ended June 30, 2011				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 418	$ 550	$ 58	$ (608)	$ 418
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	3	93	30		126
Equity compensation expense		43	3		46
Gain on sale of linefill		(15)			(15)
Net cash received for terminated interest rate or foreign currency hedging instruments	12				12
Equity earnings in unconsolidated subsidiaries, net of distributions	(573)	(29)		608	6
Other	1	(2)			(1)
Changes in assets and liabilities, net of acquisitions	603	(318)	95		380
Net cash provided by operating activities	464	322	186		972
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired		(7)	(744)		(751)
Change in restricted cash			20		20
Additions to property, equipment and other		(209)	(78)		(287)
Net cash received/(paid) for sales of linefill and base gas		(6)			(6)
Other investing activities		(3)			(3)
Net cash used in investing activities		(225)	(802)		(1,027)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on PAA s revolving credit facility	(541)	(51)			(592)
Net repayments on PNG s revolving credit facility			(34)		(34)
Net repayments on PAA s hedged inventory facility		(200)			(200)
Proceeds from the issuance of senior notes	597				597
Repayments of senior notes	(200)				(200)
Net proceeds from the issuance of common units	503				503
Cash received for sale of noncontrolling interest in a subsidiary	(230)		600		370
Net borrowings/(repayments) on intercompany notes	(200)	133	67		
Distributions paid to common unitholders and general partner	(382)				(382)
Distributions to noncontrolling interests			(16)		(16)
Other financing activities	(5)	2			(3)

Net cash provided by/(used in) financing activities	(458)	(116)	617		43
Effect of translation adjustment on cash		(1)			(1)
Net increase/(decrease) in cash and cash equivalents	6	(20)	1		(13)
Cash and cash equivalents, beginning of period	(4)	36	4		36
Cash and cash equivalents, end of period	$ 2	$ 16	$ 5	$	$ 23

34

Table of Contents

Condensed Consolidating Statements of Cash Flows (continued)

	Six Months Ended June 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 284	$ 412	$ 34	$ (446)	$ 284
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	2	106	23		131
Equity compensation expense		32	1		33
Equity earnings in unconsolidated subsidiaries, net of distributions	(411)	(34)		446	1
Gain on sale of linefill		(17)			(17)
Other	3	4			7
Changes in assets and liabilities, net of acquisitions	248	(199)	(205)		(156)
Net cash provided by/(used in) operating activities	126	304	(147)		283
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	(20)	(164)			(184)
Additions to property, equipment and other		(159)	(56)		(215)
Net cash received/(paid) for sales of linefill and base gas		19	(1)		18
Other investing activities		3			3
Net cash used in investing activities	(20)	(301)	(57)		(378)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on PAA s revolving credit facility	(36)	(114)			(150)
Net borrowings on PNG s revolving credit facility			205		205
Net borrowings on PAA s hedged inventory facility		100			100
Cash received for sale of noncontrolling interest in a subsidiary	268				268
Distributions paid to common unitholders and general partner	(335)				(335)
Other financing activities	(2)				(2)
Net cash provided by/(used in) financing activities	(105)	(14)	205		86
Effect of translation adjustment on cash		(1)			(1)
Net increase/(decrease) in cash and cash equivalents	1	(12)	1		(10)
Cash and cash equivalents, beginning of period	1	19	5		25
Cash and cash equivalents, end of period	$ 2	$ 7	$ 6	$	$ 15

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 2010 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 herein includes the following:

- Executive Summary
- Acquisitions and Internal Growth Projects
- Results of Operations
- Liquidity and Capital Resources
- Recent Accounting Pronouncements
- Critical Accounting Policies and Estimates
- Forward-Looking Statements

Executive Summary

Company Overview

We provide transportation, storage, terminalling and supply and logistics services with respect to crude oil, refined products and LPG. Through our general partner interest and majority equity ownership position in PNG, we also engage in the development and operation of 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 and Significant Activities

During the first six months of 2011, our net income attributable to Plains was $408 million, which was a $126 million increase compared to the first six months of 2010. This increase was driven by favorable results experienced within all three of our operating segments, but particularly within our supply and logistics segment. Overall this segment has benefited from the active development of crude oil and liquids-rich resource plays as well as from strong crude oil quality differentials and favorable market structure. Our facilities segment was primarily impacted by expansions to our asset base through acquisitions and our ongoing internal growth projects. Our transportation segment results were primarily driven by increased pipeline loss allowance revenues, increased volumes and favorable foreign currency exchange rates; however, such results were partially offset by the impact of a crude oil release on our Rainbow Pipeline. See the   Results of Operations   section below for further discussion and analysis of our operating segments. Additional key items impacting comparability between periods include:

- The completion of the Southern Pines Acquisition for approximately $752 million, net of cash acquired, by our subsidiary, PNG;

- The issuance of debt and equity for net proceeds of approximately $1.5 billion. This amount includes PNG s issuance of approximately 17.4 million common units to third parties for net proceeds of approximately $370 million, which was done in conjunction with the Southern Pines Acquisition;

Table of Contents

- The redemption of our 7.75% senior notes that were maturing in 2012 for approximately $222 million. In conjunction with the early redemption of these notes, we recognized a loss of approximately $23 million in Other income/(expense), net within our condensed consolidated financial statements;

- The increase in our income tax expense related to our Canadian operations as a result of Canadian tax legislation changes that became effective January 1, 2011.

Acquisitions and Internal Growth Projects

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

	Six Months Ended June 30, 2011	2010
Acquisition capital (1)	$ 764	$ 153
Internal growth projects	251	163
Maintenance capital	52	33
Total	$ 1,067	$ 349

(1) Acquisition capital for the first six months of 2011 primarily includes PNG s acquisition of SG Resources, which entity owned the Southern Pines Energy Center natural gas storage facility. This acquisition is reflected within our facilities segment and is referred to herein as the Southern Pines Acquisition. See Note 4 to our condensed consolidated financial statements for further discussion regarding our acquisition activities.

Our internal growth projects primarily relate to the construction and expansion of pipeline systems and storage and terminal facilities. The following table summarizes our more notable projects in progress during 2011 and the forecasted expenditures for the year ending December 31, 2011 (in millions):

Projects	2011
PAA Natural Gas Storage (multiple projects)	$100
Cushing - Phases IX - XI	41
Rainbow II Pipeline	36
Basile Gas Processing Facility	35
Ross (Stanley) Rail Project	32
Eagle Ford Project	31
Bone Spring Project	25
Bumstead Facility	21
Patoka Phase IV	19
Mid-Continent Project	15

Nipisi Treater	13		
Ridgelawn (Sidney) Propane Storage	13		
Basin System Expansion	12		
Other projects (1)	232		
	$625		
Potential Adjustments for Timing/Scope Refinement (2)	- $50		+ $25
Total Projected Expansion Capital Expenditures	$575	-	$650
Maintenance Capital	$95	-	$105

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2010.

(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 regulatory approvals and weather.

Results of Operations

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) and other members of management evaluate segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2010 Annual Report on Form 10-K for further discussion on how we evaluate segment performance.

Table of Contents

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 June 30, 2011	Three Months Ended June 30, 2010	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %	Six Months Ended June 30, 2011	Six Months Ended June 30, 2010	Favorable/ (Unfavorable) Variance $	Favorable/ (Unfavorable) Variance %
Transportation segment profit	$ 128	$ 130	$ (2)	(2)%	$ 265	$ 257	$ 8	3%
Facilities segment profit	86	70	16	23%	164	129	35	27%
Supply & Logistics segment profit	151	57	94	165%	285	150	135	90%
Total segment profit	365	257	108	42%	714	536	178	33%
Depreciation and amortization	(63)	(64)	1	2%	(126)	(131)	5	4%
Interest expense	(62)	(62)		%	(128)	(120)	(8)	(7)%
Other income (expense), net	2	2		%	(20)	(1)	(19)	(1,900)%
Income tax expense	(9)		(9)	N/A	(22)		(22)	N/A
Net income	233	133	100	75%	418	284	134	47%
Less: Net income attributable to noncontrolling interests	(8)	(2)	(6)	(300)%	(10)	(2)	(8)	(400)%
Net income attributable to Plains	$ 225	$ 131	$ 94	72%	$ 408	$ 282	$ 126	45%
Net income attributable to Plains:								
Earnings per basic limited partner unit	$ 1.14	$ 0.65	$ 0.49	75%	$ 2.04	$ 1.45	$ 0.59	41%
Earnings per diluted limited partner unit	$ 1.13	$ 0.65	$ 0.48	74%	$ 2.03	$ 1.45	$ 0.58	40%
Basic weighted average units outstanding	149	136	13	10%	146	136	10	7%
Diluted weighted average units outstanding	150	137	13	9%	147	137	10	7%

Non-GAAP Financial Measures

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

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

Comparability. These additional financial measures are reconciled 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 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 except for per unit amounts):

	Three Months Ended June 30,		Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Favorable/ (Unfavorable) Variance	
	2011	2010	$	%	2011	2010	$	%
Net income	$ 233	$ 133	$ 100	75%	$ 418	$ 284	$ 134	47%
Add:								
Depreciation and amortization	63	64	1	2%	126	131	5	4%
Income tax expense	9		(9)	N/A	22		(22)	N/A
Interest expense	62	62		%	128	120	(8)	(7)%
EBITDA	$ 367	$ 259	$ 108	42%	$ 694	$ 535	$ 159	30%
Selected Items Impacting Comparability of EBITDA								
Equity compensation expense (1)	(20)	(9)	(11)	(122)%	(33)	(24)	(9)	(38)%
Gains from other derivative activities (2)	21	22	(1)	(5)%	41	41		%
Net loss on early repayment of senior notes				%	(23)		(23)	N/A
Other (3)		(2)	2	100%	(5)	(3)	(2)	(67)%
Selected Items Impacting Comparability of EBITDA	$ 1	$ 11	$ (10)	(91)%	$ (20)	$ 14	$ (34)	(243)%
EBITDA	$ 367	$ 259	$ 108	42%	$ 694	$ 535	$ 159	30%
Selected Items Impacting Comparability of EBITDA	(1)	(11)	10	91%	20	(14)	34	243%
Adjusted EBITDA	$ 366	$ 248	$ 118	48%	$ 714	$ 521	$ 193	37%
Adjusted EBITDA	$ 366	$ 248	118	48%	$ 714	$ 521	193	37%
Interest expense	(62)	(62)		%	(128)	(120)	(8)	(7)%
Maintenance capital	(27)	(22)	(5)	(23)%	(52)	(33)	(19)	(58)%
Current income tax benefit/(expense)	(8)	1	(9)	(900)%	(18)	(1)	(17)	(1,700)%
Equity earnings in unconsolidated entities, net of distributions	1		1	N/A	6	1	5	500%
Distributions to noncontrolling interests (4)	(11)	(4)	(7)	(175)%	(23)	(5)	(18)	(360)%
Insurance deductible related to property damage incident				%	(1)		(1)	N/A
Implied DCF	$ 259	$ 161	$ 98	61%	$ 498	$ 363	$ 135	37%

(1) Our total equity compensation expense includes expense associated with awards that will or may be settled in units and awards that will or may be settled in cash. The awards that will or may be settled in units are included in our diluted earnings per unit calculation when the applicable performance criteria have been met. We consider the compensation expense associated with these awards as a selected item impacting comparability as the dilutive impact of the outstanding awards 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 2010 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 12 to our condensed consolidated financial statements for a comprehensive discussion regarding our derivatives and hedging activities.

(3) Includes other immaterial selected items impacting comparability such as those impacting our subsidiary, PNG.

(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. This segment generates revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees.

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

Operating Results (1)	**Three Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel amounts)	**2011**	**2010**	**$**	**%**	**2011**	**2010**	**$**	**%**
Revenues (1)								
Tariff activities	$ 247	$ 232	$ 15	6%	$ 489	$ 456	$ 33	7%
Trucking	43	27	16	59%	75	53	22	42%
Total transportation revenues	290	259	31	12%	564	509	55	11%
Costs and Expenses (1)								
Trucking costs	(31)	(18)	(13)	(72)%	(54)	(35)	(19)	(54)%
Field operating costs (excluding equity compensation expense)	(106)	(88)	(18)	(20)%	(196)	(170)	(26)	(15)%
Equity compensation expense - operations (2)	(2)	(2)		%	(5)	(4)	(1)	(25)%
Segment G&A expenses (excluding equity compensation expense)	(16)	(17)	1	6%	(32)	(33)	1	3%
Equity compensation expense - general and administrative (2)	(11)	(5)	(6)	(120)%	(17)	(12)	(5)	(42)%
Equity earnings in unconsolidated entities	4	1	3	300%	5	2	3	150%
Segment profit	$ 128	$ 130	$ (2)	(2)%	$ 265	$ 257	$ 8	3%
Maintenance capital	$ 17	$ 15	$ (2)	(13)%	$ 35	$ 22	$ (13)	(59)%
Segment profit per barrel	$ 0.46	$ 0.46	$	%	$ 0.48	$ 0.48	$	%

Average Daily Volumes	**Three Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
(in thousands of barrels per day) (3)	**2011**	**2010**	**Volumes**	**%**	**2011**	**2010**	**Volumes**	**%**
Tariff activities								
All American	35	43	(8)	(19)%	35	41	(6)	(15)%
Basin	425	369	56	15%	426	363	63	17%
Capline	187	246	(59)	(24)%	187	203	(16)	(8)%
Line 63/Line 2000	122	112	10	9%	108	111	(3)	(3)%
Salt Lake City Area Systems	138	136	2	1%	137	132	5	4%

Permian Basin Area Systems	404	387	17	4%	398	376	22	6%
Manito	66	60	6	10%	67	60	7	12%
Rainbow	122	198	(76)	(38)%	151	195	(44)	(23)%
Rangeland	57	54	3	6%	55	51	4	8%
Refined products	97	126	(29)	(23)%	97	121	(24)	(20)%
Other	1,292	1,256	36	3%	1,264	1,193	71	6%
Tariff activities total	2,945	2,987	(42)	(1)%	2,925	2,846	79	3%
Trucking	104	95	9	9%	101	92	9	10%
Transportation segment total	3,049	3,082	(33)	(1)%	3,026	2,938	88	3%

Table of Contents

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

(2) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the Selected Items Impacting Comparability section of the table as shown within the Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity compensation expense. See Note 11 to our condensed consolidated financial statements for additional discussion of 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. Transportation segment profit and segment profit per barrel were impacted by the following:

Operating Volumes and Revenues. As noted in the table above, our total transportation segment revenues, net of trucking costs, increased for both the quarter-over-quarter and year-over-year periods presented, while our volumes in the aggregate remained relatively consistent for these comparative periods. Although aggregate volumes remained relatively consistent, there were noteworthy variances on our individual pipeline systems. These variances include (i) decreased volumes on our Rainbow Pipeline System related to a pipeline release that was detected during April 2011 and pipeline downtime (see further discussion below), (ii) decreased volumes on our Capline Pipeline System, primarily related to shifts in refinery supply, (iii) lower volumes on our refined products pipeline systems, which were unfavorably impacted by refinery turnarounds during the 2011 comparative periods, (iv) increased volumes on our Basin and Permian Basin Area Systems driven by increased producer drilling in the surrounding regions and (v) additional volumes of approximately 28,000 and 27,000 barrels per day for the three and six months ended June 30, 2011, respectively, from the Robinson Lake pipeline acquired in connection with the Nexen acquisition in December 2010, which, in the Average Daily Volumes table above is included within Other. Total transportation volumes were further impacted by increased trucking volumes for the three and six months ended June 30, 2011 primarily resulting from (i) increased producer drilling and (ii) increased short-haul shipments.

As mentioned above, our transportation segment revenues, net of trucking costs, increased for the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010 and were primarily impacted by the following:

- 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 $12 million and $10 million, respectively, for the three and six months ended June 30, 2011 compared to the loss allowance revenue for the three and six months ended June 30, 2010. These increases were primarily due to a higher average realized price per barrel (including the impact of gains and losses from derivative activities), as well as increased volumes experienced during three months ended June 30, 2011 compared to corresponding 2010 period.

• Foreign Exchange Impact - Revenues and expenses from our Canadian-based subsidiaries, which use the Canadian dollar as their functional currency, are translated at the prevailing average exchange rates for each month. The average Canadian dollar to U.S. dollar exchange rate for the three-month period ended June 30, 2011 was $0.97 CAD: $1.00 USD compared to an average of $1.03 CAD: $1.00 USD for the three-month period ended June 30, 2010. The average Canadian dollar to U.S. dollar exchange rate for the six months ended June 30, 2011 was $0.98 CAD: $1.00 USD compared to an average of $1.03 CAD: $1.00 USD for the six months ended June 30, 2010. Therefore, revenues from our Canadian pipeline systems and trucking operations were favorably impacted due to the appreciation of the Canadian dollar relative to the U.S. dollar by an estimated $4 million and $8 million for the three and six months ended June 30, 2011, respectively, compared to the same 2010 periods.

• Rainbow Pipeline System As a result of a crude oil release that occurred in late April, volumes and revenues for the Rainbow Pipeline System were reduced due to pipeline downtime on a portion of the system and expenses increased due to repair and response costs. Additionally, in an unrelated development occurring shortly after the release, we experienced additional downtime and expenses related to forest fires in the same region. As a result of these matters, for the three month and six month periods ended June 30, 2011, we estimate revenues were reduced by approximately $10 million and an additional $13 million in expenses were incurred, net of estimated insurance recoveries. See Note 13 to our condensed consolidated financial statements for further information regarding this pipeline release.

Table of Contents

- Acquisitions As discussed above, we acquired the Robinson Lake pipeline as part of the December 2010 Nexen acquisition. This newly acquired pipeline contributed approximately $2 million and $4 million, respectively, in revenues for the three and six months ended June 30, 2011.

- Rate Increases Revenues were favorably impacted by increasing tariff rates primarily on our Canadian pipelines. Such increases were partially offset by decreases in rates on our FERC-regulated pipelines due to downward indexing effective July 1, 2010.

Field Operating Costs. Field operating costs (excluding equity compensation expense as discussed further below) increased during the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010 primarily due to approximately $13 million of environmental remediation expenses associated with the Rainbow Pipeline release. See Note 13 to our condensed consolidated financial statements for further information regarding this release. Excluding the impacts of these environmental remediation expenses, field operating costs in general remained relatively consistent on a per barrel basis during the comparative periods presented.

Equity Compensation Expenses. Equity compensation expenses increased for the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010. A significant component of this increase is associated with the determination that a PAA distribution level of $4.10 per unit is probable of occurring. A majority of our equity compensation awards 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 to be 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 be as if we had been accruing for these awards since the grant date.

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 2011 compared to 2010 is primarily due to increased spending on various pipeline integrity projects as well as timing of repairs between years.

Table of Contents

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 LPG, as well as LPG 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 the operating results from our facilities segment for the periods indicated:

Operating Results (1) **(in millions, except per barrel amounts)**	**Three Months Ended June 30, 2011**	**2010**	**Favorable/ (Unfavorable) Variance $**	**%**	**Six Months Ended June 30, 2011**	**2010**	**Favorable/ (Unfavorable) Variance $**	**%**
Storage and terminalling revenues (1)	$ 148	$ 121	$ 27	22%	$ 291	$ 235	$ 56	24%
Natural gas sales (2)	16		16	N/A	34		34	N/A
Storage related costs (natural gas related)	(5)	(5)		%	(10)	(12)	2	17%
Natural gas costs (2)	(15)		(15)	N/A	(33)		(33)	N/A
Field operating costs (excluding equity compensation expense)	(43)	(34)	(9)	(26)%	(83)	(68)	(15)	(22)%
Equity compensation expense - operations (3)				%	(1)	(1)		%
Segment G&A expenses (excluding equity compensation expense)	(10)	(9)	(1)	(11)%	(25)	(20)	(5)	(25)%
Equity compensation expense - general and administrative (3)	(5)	(3)	(2)	(67)%	(9)	(5)	(4)	(80)%
Segment profit	$ 86	$ 70	$ 16	23%	$ 164	$ 129	$ 35	27%
Maintenance capital	$ 7	$ 5	$ (2)	(40)%	$ 10	$ 8	$ (2)	(25)%
Segment profit per barrel	$ 0.35	$ 0.34	$ 0.01	3%	$ 0.34	$ 0.32	$ 0.02	6%

Volumes (4)(5)	**Three Months Ended June 30, 2011**	**2010**	**Favorable/ (Unfavorable) Variance Volumes**	**%**	**Six Months Ended June 30, 2011**	**2010**	**Favorable/ (Unfavorable) Variance Volumes**	**%**
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	69	61	8	13%	68	60	8	13%
Natural gas storage (average monthly capacity in billions of cubic feet)	75	49	26	53%	67	45	22	49%
LPG processing (average throughput in thousands of barrels per day)	15	14	1	7%	13	13		%
Facilities segment total (average monthly capacity in millions of barrels)	82	70	12	17%	80	68	12	18%

(1) Includes intersegment amounts.

(2) Natural gas sales and costs are attributable to the activities performed by PNG s commercial optimization group, which was established in 2010.

(3) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the Selected Items Impacting Comparability section of the table as shown within the Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity compensation expense. See Note 11 to our condensed consolidated financial statements for additional discussion of 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 segment total calculated as the sum of: (i) crude oil, refined products and LPG 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) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

Facilities segment profit and segment profit per barrel were impacted by the following:

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 and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010. The significant variances in revenues and average monthly volumes between the comparative periods are discussed below:

- Expansion Projects Expansion projects that were completed in phases throughout 2010 favorably impacted revenues and volumes during the comparative periods. These expansion projects were completed at some of our major storage and terminal locations and increased our revenues by approximately $10 million and $25 million on a combined basis for the three and six months ended June 30, 2011, respectively, compared to the same time period of 2010. Such expansion projects at these facilities increased our average monthly crude oil, refined products and LPG storage capacity by approximately 5 million barrels and 6 million barrels and our average monthly natural gas storage capacity by approximately 9 Bcf for both the three and six months ended June 30, 2011, respectively, compared to the three and six months ended June 30, 2010.

- Acquisitions Revenues and volumes for the comparative period were favorably impacted by PNG s completion of the Southern Pines Acquisition, which closed on February 9, 2011. This acquisition contributed approximately $10 million and $16 million of additional revenues, net of storage related costs, for the three and six months ended June 30, 2011, respectively.

- Other Revenues for the three and six months ended June 30, 2011 also increased as a result of volumetric gains, general escalations on existing leases and new lease contracts.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased in most categories during the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010 consistent with the overall growth of the segment through expansion projects and the Southern Pines Acquisition as discussed above. General and administrative expenses during the first three months of 2011 were impacted by approximately $4 million of acquisition-related costs. Equity compensation expense also increased for the comparative periods presented. A description of the equity compensation expense increases is included within the Transportation Segment discussion above.

Supply and Logistics Segment

Our revenues from supply and logistics activities reflect the sale of gathered and bulk-purchased crude oil, refined products and LPG 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 increases or decreases in our supply and logistics segment volumes (which consist of (i) lease gathered crude oil purchase volumes, (ii) LPG sales volumes and (iii) waterborne cargos) as well as 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 the operating results from our supply and logistics segment for the periods indicated:

Operating Results (1)	**Three Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
(in millions, except per barrel amounts)	**2011**	**2010**	**$**	**%**	**2011**	**2010**	**$**	**%**
Revenues	$ 8,586	$ 5,901	$ 2,685	46%	$ 16,022	$ 11,814	$ 4,208	36%
Purchases and related costs (2)	(8,330)	(5,773)	(2,557)	(44)%	(15,535)	(11,522)	(4,013)	(35)%
Field operating costs (excluding equity compensation expense)	(73)	(49)	(24)	(49)%	(141)	(94)	(47)	(50)%
Equity compensation expense - operations (3)	(1)		(1)	N/A	(1)	(1)		%
Segment G&A expenses (excluding equity compensation expense)	(23)	(18)	(5)	(28)%	(47)	(37)	(10)	(27)%
Equity compensation expense - general and administrative (3)	(8)	(4)	(4)	(100)%	(13)	(10)	(3)	(30)%
Segment profit	$ 151	$ 57	$ 94	165%	$ 285	$ 150	$ 135	90%
Maintenance capital	$ 3	$ 2	$ (1)	(50)%	$ 7	$ 3	$ (4)	(133)%
Segment profit per barrel	$ 2.04	$ 0.84	$ 1.20	143%	$ 1.83	$ 1.07	$ 0.76	71%

Average Daily Volumes (4)	**Three Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**		**Six Months Ended June 30,**		**Favorable/ (Unfavorable) Variance**	
(in thousands of barrels per day)	**2011**	**2010**	**Volumes**	**%**	**2011**	**2010**	**Volumes**	**%**
Crude oil lease gathering purchases	722	618	104	17%	722	610	112	18%
LPG sales	65	56	9	16%	108	95	13	14%
Waterborne cargos	31	74	(43)	(58)%	28	73	(45)	(62)%
Supply & Logistics segment total	818	748	70	9%	858	778	80	10%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $7 million and $12 million for the three and six months ended June 30, 2011, respectively, compared to $5 million and $8 million for the three and six months ended June 30, 2010, respectively.

(3) The equity compensation expense presented within the reconciliation to segment profit above includes the portion of the equity compensation expense represented by outstanding awards under the LTIPs that, pursuant to the terms of the award, will be settled in cash only and have no impact on diluted units. The equity compensation expense presented within the Selected Items Impacting Comparability section of the table as shown within the Results of Operations-Non-GAAP Financial Measures discussion above excludes this portion of the equity compensation expense.

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

Table of Contents

The NYMEX benchmark price of crude oil ranged from $90 to $115 per barrel and $64 to $87 per barrel during the three months ended June 30, 2011 and 2010, respectively, and from $84 to $115 per barrel and $64 to $87 per barrel during the six months ended June 30, 2011 and 2010, respectively. Because the commodities that we buy and sell are generally indexed to the same pricing indices for both the purchase and sale, revenues and costs related to purchases will fluctuate with market prices. However, the margins related to those purchases and sales will not necessarily have a corresponding increase or decrease. The absolute amount of our revenues and purchases increased in the three and six months ended June 30, 2011 as compared to the three and six months ended June 30, 2010, primarily resulting from higher commodity prices experienced in the 2011 period.

Generally, we expect a base level of earnings from our supply and logistics segment that may be optimized and enhanced when there is a high level of market volatility, favorable basis differentials and/or a steep contango or backwardated market structure. Our supply and logistics segment operating results are further impacted by foreign currency translations adjustments as certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Revenues and expenses are translated at average exchange rates prevailing for each month and comparison between periods may be impacted by changes in the average exchange rates. Also, our LPG 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. Supply and logistics segment profit and segment profit per barrel were impacted by the following:

Operating Revenues and Volumes. Revenues, net of purchases and related costs, for the three and six months ended June 30, 2011, increased by approximately $128 million or 100% and $195 million or 67%, compared to the three and six months periods ended June 30, 2010. Two of the principal drivers for this increase are (i) higher volumes due to increased production related to the active development of crude oil and liquids-rich resource plays and (ii) higher marketing margins related to production volumes exceeding existing pipeline takeaway capacity in certain regions and associated logistics challenges. Our results were most meaningfully impacted by increased drilling activities in the Bakken, Eagle Ford Shale, West Texas, Western Oklahoma and Texas Panhandle producing regions. Volumes also increased as a result of our December 2010 Nexen acquisition, which is primarily associated with the Bakken resource play. In addition, net revenues associated with our non-lease gathering activities increased as a result of (i) a more favorable market structure and (ii) stronger crude oil quality differentials experienced within specific regions. Waterborne cargo volumes decreased over the comparable 2011 periods, which is primarily reflective of increased domestic production.

Field Operating Costs and General and Administrative Expenses. Field operating costs and general and administrative expenses (excluding equity compensation expenses) increased in the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010 consistent with our overall segment growth including (i) increased truck-hauled lease volumes and (ii) acquisitions such as the Nexen acquisition completed in the fourth quarter of 2010. Equity compensation expense increased for the comparative periods presented. A description of the equity compensation expense increases is included within the Transportation Segment discussion above.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense decreased approximately $5 million for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. The decrease was primarily the result of extensions of the depreciable lives of several of our crude oil and other storage facilities and pipeline systems. The extension of depreciable lives is based on an internal review to assess the useful lives of our property and equipment and to adjust those lives, if appropriate, to reflect current expectations given actual experience and technology. Such decreases were partially offset by an increased amount of assets resulting from our acquisition activities, including Nexen and Southern Pines, various internal growth projects, as well as revisions of prior estimates.

Interest Expense. Interest expense increased approximately $8 million for the six months ended June 30, 2011 compared to the six months ended June 30, 2010. This increase is primarily due to the collective issuance of approximately $1.0 billion of senior notes (in January 2011 as well as in July 2010), which was partially offset by the retirement of approximately $200 million of senior notes (in February 2011).

Other Income/(Expense), Net. Other income/(expense), net was a loss of approximately $20 million for the six months ended June 30, 2011, compared to a loss of approximately $1 million for the six months ended June 30, 2010. The loss in the 2011 period is primarily related to the early redemption of our $200 million, 7.75% senior notes.

Table of Contents

Income Tax Expense. Income tax expense increased for the three and six months ended June 30, 2011 compared to the three and six months ended June 30, 2010 primarily due to an increase in the level of taxable earnings in our entities subject to Canadian federal and provincial taxes. As a result of Canadian tax legislation changes, we restructured our Canadian investment on January 1, 2011 and all of our Canadian operations are subject to Canadian corporate tax at a rate of roughly 27% in 2011. Previously a portion of the activities were conducted in a flow-through entity that was not subject to entity-level taxation. We expect that our income tax expense will increase for the remainder of 2011 as compared to the 2010 historical periods.

Liquidity and Capital Resources

General

Our primary sources of liquidity are (i) our 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, interest payments on our outstanding debt and distributions to our unitholders and General Partner, (ii) maintenance and expansion activities, (iii) acquisitions of assets or businesses and (iv) repayment of principal on our long-term debt. 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. At June 30, 2011, we had a working capital surplus of approximately $650 million and approximately $2.2 billion of liquidity available to meet our ongoing operational, investing and financing needs as noted below (in millions):

		As of June 30, 2011
Availability under PAA senior unsecured revolving credit facility	$	1,274
Availability under PAA senior secured hedged inventory facility		200
Availability under PAA 364-day senior unsecured credit facility		500
Availability under PNG senior unsecured revolving credit facility		172
Cash and cash equivalents		23
Total	$	2,169

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 material adverse effect on our financial condition, results of operations or cash flows. See Item 1A. Risk Factors in our 2010 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources. Usage of our credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

During 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which includes provisions regarding the use of derivative financial instruments. The scope and applicability of these provisions is not entirely clear and regulations implementing all the various aspects of the Act have not yet been issued. Our current assessment is that we may have additional documentation requirements. We will continue to monitor the final rules and regulations as they develop.

Cash Flows from Operating Activities

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 2010 Annual Report on Form 10-K.

Net cash flow provided by operating activities for the first six months of 2011 was approximately $972 million. The cash provided by operating activities reflects cash generated by our recurring operations, and is significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first six months of 2011, we reduced our overall inventory levels. The reduction in our crude oil inventory levels is partially due to liquidating a certain amount of inventory that had been stored in the contango market, which began to occur during the latter portion of the second quarter. The decrease was also due to the sale of LPG inventory in the beginning of the year resulting from end users increased demand for heating requirements.

Table of Contents

During the first six months of 2010, we increased the amount of our inventory. The increase in inventory was due to both increased volumes and prices and was primarily related to our crude oil contango market storage activities. During the first six months of 2010, we also increased our LPG inventory in preparation of the end users increased demand for heating requirements experienced during the winter months.

Equity and Debt Financing Activities

Our financing activities primarily relate to (i) funding acquisitions and internal capital projects, (ii) short-term working capital and hedged inventory borrowings related to our LPG business, contango market activities and foreign import activities and (iii) 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). As of June 30, 2011, 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. Our January 2011 senior notes offering and our March 2011 equity offering, as discussed further below, were both conducted under the WKSI Shelf.

PAA Equity Offering. In March 2011, we completed the issuance of 7,935,000 common units at $64.00 per unit for net proceeds of approximately $503 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 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.

PNG Equity Offering. In February 2011, in conjunction with the Southern Pines Acquisition, PNG completed a private placement of 17.4 million common units to third parties for net proceeds of approximately $370 million. See Notes 4 and 10 to our condensed consolidated financial statements for a discussion regarding this acquisition and related financing activities.

Senior Notes. In February 2011, our $200 million 7.75% senior notes due 2012 were redeemed in full. In conjunction with the early redemption, we recognized a loss of approximately $23 million. We utilized cash on hand and available capacity under our credit facilities to redeem these notes.

In January 2011, we completed the issuance of $600 million of 5.00% senior notes due February 1, 2021. The senior notes were sold at 99.521% of face value. Interest payments are due on February 1 and August 1 of each year, beginning on August 1, 2011. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities and for general partnership purposes.

Credit Facilities. During the six months ended June 30, 2011, we had net repayments on our revolving credit facilities and our hedged inventory facility in the aggregate of approximately $826 million. The net repayments resulted primarily from cash flows from operating activities, such as sales of crude oil and LPG inventory that was liquidated during the period, as well as our debt and equity activities.

During the six months ended June 30, 2010, we had net borrowings on our revolving credit facilities and our hedged inventory facility of approximately $155 million. The increased amount of borrowings during the first six months of 2010 was primarily due to increased levels of inventory resulting from the favorable contango market structure and funding our capital program.

In January 2011, we entered into a 364-day senior unsecured credit facility with an aggregate borrowing capacity of $500 million. This credit facility has a maximum debt coverage ratio of 4.75 to 1.00 (5.50 to 1.00 during an acquisition period) and matures at the earlier of January 2012 or the refinancing of our PAA senior unsecured revolving credit facility. Borrowings under this facility may be used for any partnership purpose. As of June 30, 2011, there were no outstanding borrowings under this facility.

For further discussion related to our credit facilities and long-term debt, see Liquidity and Capital Resources Credit Facilities and Long-Term Debt under Item 7 of our 2010 Annual Report on Form 10-K.

Table of Contents

Capital Expenditures and Distributions Paid to Unitholders and General Partner

We use cash primarily for our acquisition activities, internal growth projects and distributions paid to our unitholders and general partner. We have made and will continue to make capital expenditures for acquisitions, expansion capital and maintenance capital. Historically, we have financed these expenditures primarily with cash generated by operations and the financing activities discussed above. See Acquisitions and Internal Growth Projects above and under Item 7 of our 2010 Annual Report on Form 10-K for further discussion of such capital expenditures.

Distributions to 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 August 12, 2011, we will pay a quarterly distribution of $0.9825 per limited partner unit. This distribution represents a year-over-year distribution increase of approximately 4.2%. Additionally, we paid approximately $16 million for distributions to our noncontrolling interests during the six months ended June 30, 2011. See Note 10 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 of our 2010 Annual Report on Form 10-K for additional discussion of distribution thresholds.

In conjunction with the closing of certain acquisitions, our general partner agreed to temporarily reduce the amounts due it as incentive distributions. See Note 10 to our condensed consolidated financial statements for details related to the general partner s incentive distribution reduction.

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

Contingencies

For a discussion of contingencies that may impact us, see Note 13 to our condensed consolidated financial statements.

Commitments

Contractual Obligations. In the ordinary course of doing business, we purchase crude oil and LPG 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.

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 June 30, 2011 (in millions):

	2011	2012	2013	2014	2015	2016 and Thereafter	Total
Long-term debt and interest payments (1)	$ 214	$ 780	$ 736	$ 243	$ 784	$ 5,151	$ 7,908
Leases (2)	48	74	52	40	31	295	540
Other obligations (3)	107	80	37	13	5	61	303
Subtotal	369	934	825	296	820	5,507	8,751
Crude oil, refined products and LPG purchases (4)	4,874	890	348	154	90	102	6,458
Total	$ 5,243	$ 1,824	$ 1,173	$ 450	$ 910	$ 5,609	$ 15,209

(1) Includes debt service payments, interest payments due on our senior notes, interest payments and the commitment fee on the PNG credit facility and the commitment fee on our PAA revolving credit facility. Although there is an outstanding balance on

our PAA revolving credit facility at June 30, 2011, 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) storage, (ii) rights-of-way, (iii) office rent, (iv) pipeline assets, (v) compression services and (vi) trucks used in our gathering activities.

(3) Excludes a non-current liability of approximately $1 million related to derivative activity included in Crude oil, refined products, natural gas and LPG purchases.

(4) Amounts are based on estimated volumes and market prices based on average activity during June 2011. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include, as applicable, 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 obligations 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 June 30, 2011 and December 31, 2010, we had outstanding letters of credit of approximately $95 million and $75 million, respectively.

Off-Balance Sheet Arrangements

We have no significant 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 2010 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. These factors include, but are not limited to:

- 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;

- future developments and circumstances at the time distributions are declared;

- 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, refined products and liquefied petroleum gas and other natural gas related petroleum products.

Other factors, described herein, or factors that are unknown or unpredictable, could also have a material adverse effect on future results. Please read Risks Factors discussed in Item 1A of our 2010 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

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our 2010 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 10 to our condensed consolidated financial statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

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	$ 13	$ (43)	$ 43
Swaps and options contracts	2	$ (19)	$ 20
LPG and other:			
Swaps and options contracts	7	$ (7)	$ 7
Total Fair Value	$ 22		

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 (i) information required to be disclosed by us in reports that we file under the Securities Exchange Act of 1934 (the Exchange Act) is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and (ii) such information is 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.

Table of Contents

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption Litigation in Note 13 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 2010 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. [REMOVED AND RESERVED]

Item 5. OTHER INFORMATION

None.

Item 6. EXHIBITS

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	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).

Table of Contents

3.9	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).
3.10	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).
3.11	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).
3.12	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).
3.13	Sixth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated December 23, 2010 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed December 30, 2010).
3.14	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).
3.15	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).
3.16	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	Seventh Supplemental Indenture 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 4.3 to the Current Report on Form 8-K filed May 12, 2006).

Table of Contents

4.8	Eighth Supplemental Indenture dated August 25, 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 August 25, 2006).
4.9	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).
4.10	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).
4.11	Eleventh Supplemental Indenture dated November 15, 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 November 21, 2006).
4.12	Twelfth Supplemental Indenture dated January 1, 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 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	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).
4.14	Fourteenth Supplemental Indenture dated July 1, 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 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	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).
4.16	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).
4.17	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).
4.18	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).
4.19	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).

4.20	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	Assumption, Ratification and Confirmation Agreement dated January 1, 2011 by Plains Midstream Canada ULC in

	favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended (incorporated by reference to Exhibit 10.48 to the Annual Report on Form 10-K for the year ended December 31, 2010).
10.2	364-Day Credit Agreement dated January 3, 2011 among Plains All American Pipeline, L.P., as Borrower; Bank of America, N.A., as Administrative Agent; DnB NOR Bank ASA and JPMorgan Chase Bank NA, as Co-Syndication Agents; SunTrust Bank and Wells Fargo Bank, National Association, as Co-Documentation Agents; the Lenders party thereto; and Merrill Lynch, Pierce, Fenner & Smith Incorporated, DnB NOR Markets, Inc. and J.P. Morgan Securities LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 7, 2011).
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	The following financial information from the quarterly report on Form 10-Q of Plains All American Pipeline, L.P. for the quarter ended June 30, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Partners Capital, (v) Consolidated Statements of Comprehensive Income, (vi) Consolidated Statements of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Consolidated Financial Statements.

Filed herewith

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: August 5, 2011

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

Date: August 5, 2011

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	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).
3.9	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).
3.10	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).
3.11	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).
3.12	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).
3.13	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).
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3.15	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).

Table of Contents

3.16	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).
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4.8	Eighth Supplemental Indenture dated August 25, 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 August 25, 2006).
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4.13	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among

Table of Contents

	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).
4.14	Fourteenth Supplemental Indenture dated July 1, 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 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
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