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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2010

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.
(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of incorporation or organization)**	**76-0582150** **(I.R.S. Employer Identification No.)**
333 Clay Street, Suite 1600, Houston, Texas **(Address of principal executive offices)**	**77002** **(Zip Code)**

(713) 646-4100
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ 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). ☒ Yes ☐ 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 ☒ Accelerated filer ☐ Non-accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

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

As of August 2, 2010, there were 136,419,175 Common Units outstanding. The common units trade on the New York Stock Exchange under the ticker symbol "PAA."

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

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PART I. FINANCIAL INFORMATION

Item 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED BALANCE SHEETS
(in millions, except units)

	June 30, 2010 (unaudited)	December 31, 2009 (unaudited)
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 15	$ 25
Trade accounts receivable and other receivables, net	1,937	2,253
Inventory	1,483	1,157
Other current assets	63	223
Total current assets	3,498	3,658
PROPERTY AND EQUIPMENT	7,417	7,240
Accumulated depreciation	(1,007)	(900)
	6,410	6,340
OTHER ASSETS		
Linefill and base gas	504	501
Long-term inventory	118	121
Goodwill	1,285	1,287
Other, net	553	451
Total assets	$ 12,368	$ 12,358
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,181	$ 2,295
Short-term debt	1,025	1,074
Other current liabilities	171	413
Total current liabilities	3,377	3,782
LONG-TERM LIABILITIES		
Senior notes, net of unamortized discount of $13 and $14, respectively	4,137	4,136
Long-term debt under credit facilities and other	213	6
Other long-term liabilities and deferred credits	226	275
Total long-term liabilities	4,576	4,417
COMMITMENTS AND CONTINGENCIES (NOTE 10)		
PARTNERS' CAPITAL		
Common unitholders (136,419,175 and 136,135,988 units outstanding, respectively)	4,086	4,002
General partner	98	94
Total partners' capital excluding noncontrolling interests	4,184	4,096
Noncontrolling interests	231	63
Total partners' capital	4,415	4,159
Total liabilities and partners' capital	$ 12,368	$ 12,358

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per unit data)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited)		(unaudited)	
REVENUES				
Supply & Logistics segment revenues	$ 5,901	$ 4,099	$ 11,813	$ 7,231
Transportation segment revenues	139	130	277	254
Facilities segment revenues	84	53	158	100
Total revenues	6,124	4,282	12,248	7,585
COSTS AND EXPENSES				
Purchases and related costs	5,641	3,829	11,263	6,619
Field operating costs	171	160	334	312
General and administrative expenses	56	54	117	100
Depreciation and amortization	64	56	131	114
Total costs and expenses	5,932	4,099	11,845	7,145
OPERATING INCOME	192	183	403	440
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	1	5	2	8
Interest expense (net of capitalized interest of $3, $2, $9 and $5, respectively)	(62)	(56)	(120)	(107)
Other income, net	2	2	(1)	5
INCOME BEFORE TAX	133	134	284	346
Current income tax (expense)/benefit	1	—	(1)	(2)
Deferred income tax (expense)/benefit	(1)	2	1	3
NET INCOME	133	136	284	347
Less: Net income attributable to noncontrolling interests	(2)	—	(2)	—
NET INCOME ATTRIBUTABLE TO PLAINS	$ 131	$ 136	$ 282	$ 347
NET INCOME ATTRIBUTABLE TO PLAINS:				
LIMITED PARTNERS	$ 90	$ 102	$ 201	$ 282
GENERAL PARTNER	$ 41	$ 34	$ 81	$ 65
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 0.79	$ 1.45	$ 2.20
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.65	$ 0.78	$ 1.45	$ 2.18
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	136	129	136	126
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	137	130	137	127

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 284	$ 347
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	131	114
Equity compensation charge	33	30
Gain on sale of linefill	(17)	—
Inventory valuation adjustments	3	—
Other	5	(1)
Changes in assets and liabilities, net of acquisitions	(156)	(203)
Net cash provided by operating activities	283	287
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions	(184)	(56)
Additions to property, equipment and other	(215)	(228)
Cash received for sale of noncontrolling interest in a subsidiary	268	26
Net cash received for linefill	18	7
Investment in unconsolidated entities	—	(5)
Other investing activities	3	3
Net cash used in investing activities	(110)	(253)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on Plains revolving credit facility	(150)	(459)
Net borrowings on PNG revolving credit facility	205	—
Net borrowings on short-term letter of credit and hedged inventory facility	100	157
Net proceeds from the issuance of senior notes	—	350
Net proceeds from the issuance of common units	—	210
Distributions paid to common unitholders (Note 7)	(253)	(227)
Distributions paid to general partner (Note 7)	(82)	(64)
Other financing activities	(2)	(5)
Net cash used in financing activities	(182)	(38)
Effect of translation adjustment on cash	(1)	—
Net decrease in cash and cash equivalents	(10)	(4)
Cash and cash equivalents, beginning of period	25	11
Cash and cash equivalents, end of period	$ 15	$ 7
Cash paid for interest, net of amounts capitalized	$ 123	$ 103
Cash paid/(refunded) for income taxes, net	$ 20	$ 7

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL
(in millions)

	Common Units		General Partner	Partners' Capital Excluding Noncontrolling Interests	Noncontrolling Interests	Partners' Capital
	Units	Amount				
				(unaudited)		
Balance, December 31, 2009	136	$ 4,002	$ 94	$ 4,096	$ 63	$ 4,159
Net income	—	201	81	282	2	284
Sale of noncontrolling interest in a subsidiary (Note 7)	—	99	2	101	167	268
Distributions to limited partners and general partner (Note 7)	—	(253)	(82)	(335)	—	(335)
Issuance of common units under LTIP	—	16	—	16	—	16
Other comprehensive income	—	19	—	19	—	19
Other	—	2	3	5	(1)	4
Balance, June 30, 2010	136	$ 4,086	$ 98	$ 4,184	$ 231	$ 4,415

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(unaudited)		(unaudited)	
Net income	$ 133	$ 136	$ 284	$ 347
Other comprehensive income/(loss)	(45)	(32)	19	(152)
Comprehensive income	88	104	303	195
Less: Comprehensive income attributable to noncontrolling interests	(2)	—	(2)	—
Comprehensive income attributable to Plains	$ 86	$ 104	$ 301	$ 195

CONDENSED CONSOLIDATED STATEMENT OF
CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME
(in millions)

	Derivative Instruments	Translation Adjustments	Other	Total
		(unaudited)		
Balance, December 31, 2009	$ 18	$ 106	$ (1)	$ 123
Reclassification adjustments	29	—	—	29
Net deferred gains on cash flow hedges	14	—	—	14
Currency translation adjustment	—	(24)	—	(24)
Total period activity	43	(24)	—	19
Balance, June 30, 2010	$ 61	$ 82	$ (1)	$ 142

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE 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. We also engage in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. See Note 11 for further detail of our operating segments.

As used in this Form 10-Q, the terms "Partnership," "Plains," "we," "us," "our," "ours" and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless the context indicates otherwise. 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
API 653	= American Petroleum Institute Standard 653
Bcf	= Billion cubic feet
CAA	= Clean Air Act
CAD	= Canadian Dollar
Class B units	= Class B units of Plains AAP, L.P.
DCP	= Disclosure controls and procedures
DERs	= Distribution Equivalent Rights
DOJ	= United States Department of Justice
EPA	= United States Environmental Protection Agency
FERC	= Federal Energy Regulation Commission
FASB	= Financial Accounting Standards Board
ICE	= IntercontinentalExchange
IPO	= Initial Public Offering
LIBOR	= London Interbank Offered Rate
LPG	= Liquefied petroleum gas and other natural gas-related petroleum products
LTIP	= Long term incentive plan
Mcf	= Thousand cubic feet
MLP	= Master limited partnership
MTBE	= Methyl tertiary-butyl ether
NJDEP	= New Jersey Department of Environmental Protection
NYMEX	= New York Mercantile Exchange
NPNS	= Normal purchase and normal sale
PNG	= PAA Natural Gas Storage, L.P.
PNGS	= PAA Natural Gas Storage, LLC
PAT	= Pacific Atlantic Terminals, LLC
Rainbow	= Rainbow Pipe Line Company Ltd.
RMPS	= Rocky Mountain Pipeline System
SEC	= Securities and Exchange Commission
U.S. GAAP	= United States generally accepted accounting principles
USD	= United States Dollar
WTI	= West Texas Intermediate

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 2009 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, and 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. The condensed balance sheet data as of December 31, 2009 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, 2010 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.

Note 2—Recent Accounting Pronouncements

Fair Value Measurement Disclosure Requirements. In January 2010, the FASB issued guidance relating to fair value measurements. This new guidance requires additional disclosures regarding transfers in and out of Level 1 and Level 2 measurements and requires a gross presentation of activities within the Level 3 roll forward. This guidance is effective for the first interim or annual reporting period beginning after December 15, 2009, except for the gross presentation of the Level 3 roll forward, which is required for annual reporting periods beginning after December 15, 2010 and for interim reporting periods within those years. We adopted the guidance, which is effective for the first interim or annual reporting period beginning after December 15, 2009, on January 1, 2010. Our adoption did not have any material impact on our financial position, results of operations, or cash flows. See Note 9 for applicable disclosure. We will adopt the guidance that will be effective for annual reporting periods beginning after December 15, 2010 on January 1, 2011. We do not expect that adoption of this guidance will have any 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, 2010 and December 31, 2009, 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 $4 million and $9 million at June 30, 2010 and December 31, 2009, respectively. The decrease in our allowance for doubtful accounts receivable balance during the six months ended June 30, 2010 primarily is due to the collection and related settlement of claims for receivables that had been reserved for during the years ended December 31, 2009 and 2008. Although we consider our allowance for doubtful accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

At June 30, 2010 and December 31, 2009, we had received approximately $201 million and $212 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—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 millions and total value in millions):

	June 30, 2010				December 31, 2009			
	Volumes	Unit of Measure	Total Value	Price/ Unit [1]	Volumes	Unit of Measure	Total Value	Price/ Unit [1]
Inventory								
Crude oil	16,233	barrels	$ 1,179	$ 72.63	12,232	barrels	$ 886	$ 72.43
LPG	6,195	barrels	301	$ 48.59	6,051	barrels	247	$ 40.82
Refined products	37	barrels	2	$ 54.05	283	barrels	21	$ 74.20
Natural gas [2]	110	mcf	—	$ 3.36	181	mcf	1	$ 3.30
Parts and supplies	N/A		1	N/A	N/A		2	N/A
Inventory subtotal			1,483				1,157	
Linefill and base gas								
Crude oil	9,162	barrels	462	$ 50.43	9,404	barrels	471	$ 50.09
Natural gas [2]	11,194	mcf	38	$ 3.39	9,194	mcf	28	$ 3.04
LPG	79	barrels	4	$ 50.63	52	barrels	2	$ 38.46
Linefill and base gas subtotal			504				501	
Long-term inventory								
Crude oil	1,425	barrels	97	$ 68.07	1,497	barrels	103	$ 68.80
LPG	487	barrels	21	$ 43.12	458	barrels	18	$ 39.30
Long-term inventory subtotal			118				121	
Total			$ 2,105				$ 1,779	

(1) Price per unit represents a weighted average associated with various grades, qualities, and locations; accordingly, these prices may not be comparable to published benchmarks for such products.

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

The inventory balances at June 30, 2010 include an inventory valuation adjustment, which resulted in a loss of approximately $3 million, related to certain crude oil inventories that were revalued to market prices at June 30, 2010.

Note 5—Debt

Debt consists of the following (in millions):

	June 30, 2010	December 31, 2009
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.6% and 2.5% as of June 30, 2010 and December 31, 2009, respectively	$ 400	$ 300
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% for both periods presented [1]	623	772
Other	2	2
Total short-term debt	1,025	1,074
Long-term debt:		
Senior notes, net of unamortized discounts [2]	4,137	4,136
Long-term debt under credit facilities and other [3]	213	6
Total long-term debt [1] [4]	4,350	4,142
Total debt	$ 5,375	$ 5,216

(1) We classify borrowings under our senior unsecured revolving credit facility as short-term. 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) A portion of this balance consists of our $500 million of 4.25% senior notes due September 2012 that were issued in July 2009 and the proceeds from which are being used to supplement capital available from our hedged inventory facility. At June 30, 2010 and December 31, 2009, approximately $500 million and $222 million, respectively, had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

(3) In April 2010, our consolidated subsidiary PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. This credit facility, which bears interest based on LIBOR plus an applicable margin (as defined by the credit agreement), may be expanded to $600 million, subject to additional lender commitments and with approval of the administrative agent for the credit facility. At June 30, 2010, borrowings of approximately $205 million were outstanding under this facility. See the "*Sale of Noncontrolling Interest in a Subsidiary*" section of Note 7 for additional discussion regarding PNG.

(4) Our fixed-rate senior notes have a face value of approximately $4.2 billion as of June 30, 2010. We estimate the aggregate fair value of these notes as of June 30, 2010 to be approximately $4.4 billion. 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.

Senior Notes

In July 2010, we completed the issuance of $400 million of 3.95% Senior Notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, beginning on September 15, 2010. We used the net proceeds from this offering to repay outstanding indebtedness under our credit facilities, which may be reborrowed to fund our ongoing expansion capital program, potential future acquisitions or the potential redemption of our outstanding 6.25% senior notes that mature in September 2015.

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, 2010 and December 31, 2009, we had outstanding letters of credit of approximately $103 million and $76 million, respectively.

Note 6—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, 2010 and 2009 (amounts in millions, except per unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Numerator for basic and diluted earnings per limited partner unit:				
Net income attributable to Plains	$ 131	$ 136	$ 282	$ 347
Less: General partner's incentive distribution paid [1]	(39)	(32)	(77)	(60)
Subtotal	92	104	205	287
Less: General partner 2% ownership [1]	(2)	(2)	(4)	(5)
Net income available to limited partners	90	102	201	282
Adjustment in accordance with application of the two-class method for MLPs [1]	(1)	—	(3)	(5)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 89	$ 102	$ 198	$ 277
Denominator:				
Basic weighted average number of limited partner units outstanding	136	129	136	126
Effect of dilutive securities:				
Weighted average LTIP units [2]	1	1	1	1
Diluted weighted average number of limited partner units outstanding	137	130	137	127
Basic net income per limited partner unit	$ 0.65	$ 0.79	$ 1.45	$ 2.20
Diluted net income per limited partner unit	$ 0.65	$ 0.78	$ 1.45	$ 2.18

(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 8) 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 7—Partners' Capital and Distributions

Sale of Noncontrolling Interest in a Subsidiary

On May 5, 2010, PNG completed its IPO of 13,478,000 common units representing limited partner interests at $21.50 per common unit. The number of units issued at closing included 1,758,000 common units issued pursuant to the full exercise of the underwriters' over-allotment option. Net proceeds received by PNG from the sale of the 13,478,000 common units were approximately $268 million and were used to repay amounts outstanding under our credit facilities and for general partnership purposes. The common units offered represent approximately 23% of the outstanding equity of PNG. We own the remaining 77% equity interest in PNG and control the entity, and therefore, continue to consolidate the financial results.

Prior to the PNG IPO, we owned 100% of PNGS' natural gas storage business, the predecessor of PNG, and related operating entities. Immediately prior to the closing of the IPO, we contributed 100% of the equity interests in PNGS and its subsidiaries to PNG in exchange for approximately 18.1 million common units, approximately 13.9 million Series A subordinated units, 11.5 million Series B subordinated units and a 2% general partner interest and incentive distribution rights. In conjunction with the offering, we recorded non-controlling interest of $167 million associated with the book value of PNG sold to the public. We also recorded an increase to our partners' capital of approximately $101 million associated with the net increase from our share of the proceeds received in the offering partially offset by the dilution of our interest in PNG resulting from the IPO.

The Series A subordinated units are not entitled to receive any distributions until the common units have received the minimum quarterly distribution ($1.35 on an annualized basis) plus any arrearages in the payment of the minimum quarterly distribution from prior quarters. The Series A subordinated units will convert to common units once certain earnings and distribution targets are met for three consecutive, non-overlapping four quarter periods. The Series B subordinated units are not entitled to participate in quarterly distributions until they convert into Series A subordinated units. The Series B subordinated units will convert into Series A subordinated units upon satisfaction of the following operational and financial conditions:

- 4,600,000 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 29.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.36 per unit (representing an annualized distribution of $1.44 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and (c) PNG makes a quarterly distribution of available cash of at least $0.36 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2.0% interest and the related distributions on the incentive distribution rights;
- 3,833,333 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 35.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.3825 per unit (representing an annualized distribution of $1.53 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior bullet, and (c) PNG makes a quarterly distribution of available cash of at least $0.3825 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2.0% interest and the related distributions on the incentive distribution rights; and
- 3,066,667 Series B subordinated units will convert into Series A subordinated units on a one-for-one basis if (a) the aggregate amount of working gas storage capacity at Pine Prairie that has been placed into service totals at least 41.6 Bcf, (b) PNG generates distributable cash flow for two consecutive quarters sufficient to pay a quarterly distribution of at least $0.4075 per unit (representing an annualized distribution of $1.63 per unit) on the weighted average number of outstanding common units and Series A subordinated units and all of such Series B subordinated units and, if any, the Series B subordinated units described in the prior two bullets, and (c) PNG makes a quarterly distribution of available cash of at least $0.4075 per quarter for two consecutive quarters on all outstanding common units and Series A subordinated units and the corresponding distributions on PNG's general partner's 2.0% interest and the related distributions on the incentive distribution rights.

PNG's general partner will determine whether the in-service operational tests set forth above have been satisfied. To the extent that the operational tests described above are satisfied prior to or during the two-quarter period applicable to the financial tests described above, the holder of the Series B subordinated units subject to conversion will be entitled to receive the quarterly distribution payable with respect to the second quarter of such two-quarter period. In all other circumstances, where the operational tests are satisfied following the two-quarter period applicable to the financial tests, the holder of the Series B subordinated units subject to conversion will be entitled to receive any distribution payable following the satisfaction of such operational tests.

Any Series B subordinated units that remain outstanding as of December 31, 2018 will automatically be cancelled.

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

	For the Six Months Ended June 30, 2010	2009
Beginning balance	$ 63	$ —
Sale of noncontrolling interests in subsidiaries	167	64
Net income attributable to noncontrolling interests	2	2
Other	(1)	(3)
Ending Balance	$ 231	$ 63

PAA Equity Offerings

We did not complete any equity offerings during the six months ended June 30, 2010; however, we completed the following equity offering of our common units during the six months ended June 30, 2009 (in millions, except unit and per unit data):

Period	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
March 2009 [(1)]	5,750,000	$ 36.90	$ 212	$ 4	$ (6)	$ 210

(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.

PAA Distributions

The following table details the distributions pertaining to the first six months of 2010 and 2009, 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	General Partner: Incentive	General Partner: 2%	Total	Distributions per limited partner unit
2010						
July 13, 2010	August 13, 2010 [(1)]	$ 129	$ 40	$ 3	$ 172	$ 0.9425
April 13, 2010	May 14, 2010	$ 127	$ 39	$ 3	$ 169	$ 0.9350
January 20, 2010	February 12, 2010	$ 126	$ 37	$ 3	$ 166	$ 0.9275
2009						
July 15, 2009	August 14, 2009	$ 117	$ 32	$ 2	$ 151	$ 0.9050
April 8, 2009	May 15, 2009	$ 117	$ 32	$ 2	$ 151	$ 0.9050
January 14, 2009	February 13, 2009	$ 110	$ 28	$ 2	$ 140	$ 0.8925

(1) Payable to unitholders of record on August 3, 2010, for the period April 1, 2010 through June 30, 2010.

Upon closing of the Pacific acquisition in November 2006, the Rainbow acquisition in May 2008 and the PNGS acquisition in September 2009, our general partner agreed to reduce the amounts due it as incentive distributions. The total reduction in incentive distributions related to these acquisitions is $83 million. Following the distribution in August 2010, the aggregate incentive distribution reductions remaining will be approximately $11 million. See Note 2 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K for further detail regarding our "*General Partner Incentive Distributions*."

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Note 8—Equity Compensation Plans

For discussion of our LTIP awards, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K.

On April 27, 2010, PNG's general partner adopted the PAA Natural Gas Storage, L.P. 2010 Long Term Incentive Plan (the "PNG 2010 LTIP Plan"). The PNG 2010 LTIP Plan consists of restricted units, phantom units, unit options, unit appreciation rights and unit awards. The PNG 2010 LTIP Plan limits the number of PNG common units that may be delivered pursuant to awards under the plan to 3,000,000. In May 2010, PNG's board of directors approved the grant of 658,500 phantom units (representing approximately 1% of the currently outstanding PNG limited partner units) under the PNG 2010 LTIP Plan to directors, officers and other employees of PNG, a portion of which were granted upon conversion of outstanding awards denominated in common units of PAA.

At June 30, 2010, the following LTIP awards, denominated in PAA units, were outstanding (units in millions):

LTIP Units Outstanding	PAA Distribution Required	2010	2011	2012	2013	2014	2015
2.8(1)	\$3.50 - \$4.45	—	0.5	0.8	0.5	0.5	0.5
1.7(2)	\$3.50 - \$4.25	0.5	0.2	0.7	0.2	0.1	—
4.5(3)(4)		0.5	0.7	1.5	0.7	0.6	0.5

(1) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between \$3.50 and \$4.45 and vest upon the later of a certain date or the attainment of such levels. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between \$3.50 and \$4.25. For a majority of these LTIP awards, fifty percent will vest at specified dates regardless of whether the performance conditions are attained. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(3) Approximately 3 million of our approximately 4.5 million outstanding LTIP awards also include DERs, of which approximately 1 million are currently earned.

(4) LTIP units outstanding do not include Class B units described below.

Additionally, at June 30, 2010, the following LTIP awards, denominated in PNG units, were outstanding (units in millions):

LTIP Units Outstanding	PNG Distribution Required	2010	2011	2012	2013	2014	2015
0.4(1)	\$1.55 - \$1.90	—	—	0.1	—	0.1	0.2
0.3(2)	Other	—	0.1	0.1	0.1	—	—
0.7(3)		—	0.1	0.2	0.1	0.1	0.2

(1) These LTIP awards have performance conditions requiring the attainment of an annualized PNG distribution of between \$1.55 and \$1.90 and vest upon the later of a certain date or the attainment of such levels. For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(2) These LTIP awards have performance conditions requiring the conversion of PNG's Series A and Series B subordinated units (see Note 7). For purposes of this disclosure, vesting dates are based on an estimate of future distribution levels and assume that all grantees remain employed by us through the vesting date.

(3) Approximately 0.3 million of these LTIP awards also include DERs, of which none are currently earned.

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Our LTIP 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, 2009	3.9	$	36.40	—	$	—
Granted	1.5	$	42.39	0.7	$	19.72
Vested	(0.6)	$	34.67		$	
Cancelled or forfeited	(0.3)	$	33.53	—	$	—
Outstanding, June 30, 2010 (1) (2)	4.5	$	38.93	0.7	$	19.72

(1) PAA includes approximately 1 million equity classified awards.

(2) The majority of the PNG awards are equity classified.

Our accrued liability at June 30, 2010 related to all outstanding liability classified LTIP awards and DERs is approximately $78 million. This liability includes accruals associated with our assessment that an annualized PAA distribution of $3.90 is probable. This liability also includes accruals associated with our assessment that an annualized PNG distribution of $1.45 and the conversion of PNG's Series A subordinated units and the first tranche of PNG's Series B subordinated units are probable of occurring. At December 31, 2009, the accrued liability was approximately $87 million.

Class B Units of PAA's General Partner

For further discussion of the Class B units, see Note 10 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K. The following table contains a summary of Class B unit awards that were (i) reserved for future grants (ii) outstanding and (iii) earned as of and for the six months ended June 30, 2010 and as of December 31, 2009:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned		Grant Date Fair Value Of Outstanding Class B Units (1) (in millions)
Balance, December 31, 2009	34,500	165,500	38,500	$	36
Class B unit issuance	—	—	—		—
Class B units earned	—	—	—		—
Class B units forfeited	1,500	(1,500)	(375)		—
Balance, June 30, 2010	36,000	164,000	38,125	$	36

(1) Of the grant date fair value, approximately $2 million was recognized as expense during the six months ended June 30, 2010.

Class B Units of PNG's General Partner

In July 2010, the Board of Directors of PNG's general partner authorized the issuance of 165,000 Class B Units ("PNG Class B Units") of PNGS GP LLC (PNG's general partner). Approximately 97,625 PNG Class B Units were awarded and the remaining units are reserved for future grants. The PNG Class B Units are earned in 25% increments 180 days following annualized PNG distribution levels of $2.00, $2.30, $2.50 and $2.70. When earned, the PNG Class B Units participate in quarterly distributions paid to PNGS GP LLC to the extent such distributions exceed $2.5 million per quarter. Assuming all 165,000 PNG Class B Units were granted and earned, the maximum participation rate would be 6% of PNG's quarterly general partner distribution.

Other Consolidated Equity Compensation Information

We refer to our PAA LTIP plans, the PNG 2010 LTIP Plan and the Class B units of PAA's general partner collectively as "Equity compensation plans." 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, 2010		Three Months Ended June 30, 2009	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity compensation expense	$ 12	$ 2	$ 18	$ 1
LTIP unit vestings	$ 25	$ —	$ 18	$ —
LTIP cash settled vestings	$ 10	$ —	$ 7	$ —
DER cash payments	$ 1	$ —	$ 1	$ —

	Six Months Ended June 30, 2010		Six Months Ended June 30, 2009	
	Liability Awards	Equity Awards	Liability Awards	Equity Awards
Equity compensation expense	$ 29	$ 4	$ 28	$ 2
LTIP unit vestings	$ 25	$ —	$ 18	$ —
LTIP cash settled vestings	$ 10	$ —	$ 7	$ —
DER cash payments	$ 2	$ —	$ 2	$ —

Based on the June 30, 2010 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $62 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value of our Equity compensation plans. For our liability classified awards, this estimate is based on the closing market price of our units of $58.70 at June 30, 2010. For our equity classified awards, this estimate is based on the closing price of the applicable units (PAA or PNG) as of the grant date. Actual amounts may differ materially as a result of a change in the market price of our units and/or probability assessment regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity Compensation Expense (1) (2)
2010 (3)	$ 18
2011	24
2012	15
2013	4
2014	1
Total	$ 62

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at June 30, 2010.

(2) Includes unamortized fair value associated with Class B units.

(3) Includes equity compensation plan fair value amortization for the remaining six months of 2010.

Note 9—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. 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 policy is to use derivative instruments only for risk management purposes. Our commodity risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity, to help ensure that our hedging activities address our risks. Our interest rate and foreign currency 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. A discussion of our derivative activities by risk category follows.

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 purchase only product for which we have a market, (ii) to structure our sales contracts so that price fluctuations do not materially affect the segment profit we earn, and (iii) not to acquire and hold physical inventory, futures contracts or other derivative products for the purpose of speculating on outright commodity price changes. Although we seek to maintain positions that are substantially balanced, we purchase crude oil, refined products and LPG from thousands of locations and may experience net unbalanced positions as a result of production, transportation and delivery variances, as well as logistical issues associated with inclement weather conditions and other uncontrollable events that occur within each month. In connection with our efforts to maintain a balanced position, specifically authorized personnel can purchase or sell an aggregate limit of up to 810,000 barrels of crude oil, refined products and LPG relative to the volumes originally scheduled for such month, based on interim information. The purpose of these purchases and sales is to manage risk as opposed to establishing a risk position. When unscheduled physical inventory builds or draws do occur, they are monitored constantly and managed to a balanced position over a reasonable period of time.

The 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 supply and logistics operations, we purchase and sell crude oil, LPG, and refined products. We use derivatives to manage the associated risks and to optimize profits. As of June 30, 2010, net derivative positions related to these activities included:

- An approximate 209,500 barrels per day net long position (total of 6.3 million barrels) associated with our crude oil activities, which was unwound ratably during July 2010 to match monthly average pricing.
- An approximate 23,800 barrels per day (total of 13.5 million barrels) net short spread position, which hedges a portion of our anticipated crude oil lease gathering purchases through January 2012. These derivatives protect our margin on future floating-price crude oil purchase commitments. These derivatives in the aggregate do not result in exposure to outright price movements.
- A net short spread position averaging approximately 1,000 barrels per day (total of 0.5 million barrels) of calendar spread call options for the period July 2010 through January 2012. These derivatives in the aggregate do not result in exposure to outright price movements.

- An average of approximately 2,400 barrels per day (total of 0.6 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 2011.
- Approximately 8,000 barrels per day on average (total of 4.3 million barrels) of WTS/WTI crude oil basis swaps through December 2011, which hedge anticipated sales of crude oil (WTI).

Storage Capacity Utilization — We own approximately 62 million barrels of crude oil, LPG and refined products storage capacity that is not 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, 2010, we used derivatives to manage the risk of not utilizing approximately 2.4 million barrels per month of storage capacity through 2011. These positions are a combination of calendar spread options and NYMEX 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. These activities primarily relate to the seasonal storage of LPG inventories and contango market storage activities. When we purchase and store barrels, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of June 30, 2010, we had approximately 13.6 million barrels of inventory hedged with derivatives.

We also purchase foreign cargoes of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of foreign crude inventory. As of June 30, 2010, we had approximately 1.9 million barrels of crude oil derivatives hedging the anticipated sale of foreign 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, 2010, we had PLA hedges consisting of (i) a net short position consisting of crude oil futures and swaps for an average of approximately 2,200 barrels per day (total of 2.0 million barrels) through December 2012, (ii) a long put option position of approximately 0.4 million barrels through December 2012 and (iii) a long call option position of approximately 1.3 million barrels through December 2011.

Diluent Purchases — We use diluent in our Canadian crude oil pipeline operations and have used derivative instruments to hedge the anticipated forward purchases of diluent and diluent inventory. As of June 30, 2010, we had an average of 1,200 barrels per day of natural gasoline/WTI spread positions (approximately 1 million barrels) that run through 2011.

Natural Gas Purchases — 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, 2010, we have a long position of approximately 1 Bcf consisting of natural gas futures contracts through August 2011 and natural gas call options for approximately 1 Bcf through August 2011.

The derivative instruments we use to manage our commodity price risk consist primarily of futures, options and swaps traded on the NYMEX and ICE and in over-the-counter transactions. Over-the-counter transactions include commodity swap and option contracts. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred into AOCI and recognized in revenues or purchases and related costs in the periods during which the underlying physical transactions occur. We have determined that substantially all of our physical purchase and sale agreements qualify for the NPNS exclusion and thus are not subject to the accounting treatment for derivative instruments and hedging activities as set forth in FASB guidance. 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 as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and, in certain cases, 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, 2010, AOCI includes deferred losses of $7 million that relate to terminated interest rate swaps and treasury locks that were designated for hedge accounting. These terminated interest rate derivatives were cash-settled in connection with the issuance and refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the hedged debt instruments.

As of June 30, 2010, we had four outstanding interest rate swaps and three outstanding 10-year treasury locks. For the interest rate swaps, 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 2011 and two of the swaps terminate in 2012. The 10-year treasury locks have an aggregate notional amount of $150 million and an average locked rate of 3.14%. All three 10-year treasury locks terminated in July 2010.

Currency Exchange Rate Risk Hedging

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. 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 certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments include foreign currency exchange contracts, forwards and options. As of June 30, 2010, AOCI includes net deferred gains of $17 million that relate to open and settled forward exchange contracts that were designated for hedge accounting. These forward exchange contracts hedge the cash flow variability associated with CAD-denominated interest payments on a CAD-denominated intercompany note as a result of changes in the foreign exchange rate.

As of June 30, 2010, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. 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 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.

At June 30, 2010, our open foreign exchange derivatives included forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

	CAD	USD	Average Exchange Rate
2010	$ 22	$ 19	CAD $1.14 to USD $1.00
2011	$ 15	$ 15	CAD $1.01 to USD $1.00
2012	$ 15	$ 15	CAD $1.01 to USD $1.00
2013	$ 9	$ 9	CAD $1.00 to USD $1.00

These financial instruments are placed with large, highly rated financial institutions.

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Summary of Financial Impact

The majority of our derivative activity is related to our commodity price-risk hedging activities. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for 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. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is 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.

A summary of the impact of our derivative activities recognized in earnings for the three and six months ended June 30, 2010 and 2009 is as follows (in millions):

Three months ended June 30, 2010 and 2009:

	Three Months Ended June 30, 2010				Three Months Ended June 30, 2009			
	Derivatives in Cash Flow Hedging Relationships		Derivatives Not Designated as a Hedge (3)		Derivatives in Cash Flow Hedging Relationships		Derivatives Not Designated as a Hedge (3)	
Location of gain/(loss)	AOCI Reclass (1)	Ineffective Portion (2)		Total	AOCI Reclass (1)	Ineffective Portion (2)		Total
Commodity Derivatives								
Supply and Logistics segment revenues	$ (7)	$ 1	$ 28	$ 22	$ 16	$ (7)	$ 35	$ 44
Transportation segment revenues	—	—	—	—	1	—	—	1
Purchases and related costs	(8)	—	11	3	1	—	20	21
Interest Rate Derivatives								
Interest expense	—	—	1	1	—	—	—	—
Foreign Exchange Derivatives								
Supply and Logistics segment revenues	—	—	(3)	(3)	—	—	5	5
Purchases and related costs	—	—	—	—	—	—	2	2
Other income, net	—	—	1	1	—	—	(2)	(2)
Total Gain/(Loss) on Derivatives Recognized in Income	**$ (15)**	**$ 1**	**$ 38**	**$ 24**	**$ 18**	**$ (7)**	**$ 60**	**$ 71**

Six months ended June 30, 2010 and 2009:

	Six Months Ended June 30, 2010				Six Months Ended June 30, 2009			
	Derivatives in Cash Flow Hedging Relationships		Derivatives Not Designated as a Hedge [3]		Derivatives in Cash Flow Hedging Relationships		Derivatives Not Designated as a Hedge [3]	
Location of gain/(loss)	AOCI Reclass [1]	Ineffective Portion [2]		Total	AOCI Reclass [1]	Ineffective Portion [2]		Total
Commodity Derivatives								
Supply and Logistics segment revenues	$ (26)	$ —	$ 55	$ 29	$ 141	$ (8)	$ 6	$ 139
Transportation segment revenues	1	—	—	1	3	—	—	3
Facilities segment revenues	(1)	—	1	—	—	—	—	—
Purchases and related costs	(3)	—	(13)	(16)	(31)	—	115	84
Interest Rate Derivatives								
Other income, net	—	—	—	—	—	—	(1)	(1)
Interest expense	—	—	2	2	—	—	—	—
Foreign Exchange Derivatives								
Supply and Logistics segment revenues	—	—	(3)	(3)	—	—	5	5
Purchases and related costs	—	—	2	2	—	—	(3)	(3)
Other income, net	—	—	—	—	5	—	(2)	3
Total Gain/(Loss) on Derivatives Recognized in Income	**$ (29)**	**$ —**	**$ 44**	**$ 15**	**$ 118**	**$ (8)**	**$ 120**	**$ 230**

(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 represent the ineffective portion of the fair value of our unrealized cash flow hedges that were recognized in earnings during the period.

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

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The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of June 30, 2010 (in millions):

As of June 30, 2010

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 210	Other current assets	$ (88)
	Other long-term assets	26	Other long-term assets	—
	Other long-term liabilities	1	Other long-term liabilities	(1)
	Other current liabilities	—	Other current liabilities	(3)
Interest rate derivatives	Other current liabilities	—	Other current liabilities	(2)
Foreign exchange derivatives	Other long-term assets	2	Other long-term liabilities	—
Total derivatives designated as hedging instruments		$ 239		$ (94)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 150	Other current assets	$ (114)
	Other long-term assets	27	Other long-term assets	(14)
	Other long-term liabilities	1	Other long-term liabilities	(2)
Interest rate derivatives	Other current assets	1	Other current assets	—
	Other long-term assets	2	Other long-term assets	—
	Other current liabilities	1	Other current liabilities	—
Foreign exchange derivatives	Other current liabilities	—	Other current liabilities	(3)
Total derivatives not designated as hedging instruments		$ 182		$ (133)
Total derivatives		$ 421		$ (227)

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet on a gross basis as of December 31, 2009 (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	$ 153	Other current liabilities	$ (140)
	Other long-term assets	34	Other long-term liabilities	(1)
Foreign exchange derivatives	Other long-term assets	2	Other long-term liabilities	—
Total derivatives designated as hedging instruments		$ 189		$ (141)
Derivatives not designated as hedging instruments:				
Commodity derivatives	Other current assets	$ 34	Other current liabilities	$ (91)
	Other long-term assets	41	Other long-term liabilities	(34)
Interest rate derivatives	Other current assets	1	Other current liabilities	—
	Other long-term assets	1	Other long-term liabilities	—
Foreign exchange derivatives	Other current assets	2	Other current liabilities	(3)
Total derivatives not designated as hedging instruments		$ 79		$ (128)
Total derivatives		$ 268		$ (269)

As of June 30, 2010, there was a net gain of $61 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 physical 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, 2010, we expect to reclassify a net gain of approximately $27 million to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 98% is expected to be reclassified to earnings prior to 2013 with the remaining deferred gain being reclassified to earnings through 2019. 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 six months ended June 30, 2009, we discontinued a cash flow hedge as a result of the hedged transaction becoming no longer probable of occurring and reclassified a deferred gain of approximately $6 million from AOCI to other income. During the three months ended June 30, 2010 and 2009 and the six months ended June 30, 2010, all of our hedged transactions were probable of occurring.

Net deferred gain/(loss) recognized in AOCI on derivatives (effective portion) during the three and six months ended June 30, 2010 and June 30, 2009 are as follows (in millions):

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Commodity derivatives	$ 18	$ (104)	$ 14	$ (82)
Foreign exchange derivatives	—	(4)	(1)	(2)
Interest rate derivatives	1	—	1	—
Total	$ 19	$ (108)	$ 14	$ (84)

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, 2010, we had a net broker payable of approximately $130 million (consisting of initial margin of $45 million reduced by $175 million of variation margin that had been returned to us). As of December 31, 2009, we had a net broker receivable of approximately $53 million (consisting of initial margin of $71 million reduced by $18 million of variation margin that had been returned to us).
At June 30, 2010 and December 31, 2009, 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, 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 does affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of June 30, 2010 (in millions)				Fair Value as of December 31, 2009 (in millions)			
Recurring Fair Value Measures[1]	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Commodity derivatives	$ 186	$ —	$ 7	$193	$ 27	$ —	$ (31)	$ (4)
Interest rate derivatives	—	—	2	2	—	—	2	2
Foreign currency derivatives	—	—	(1)	(1)	—	—	1	1
Total	$ 186	$ —	$ 8	$194	$ 27	$ —	$ (28)	$ (1)

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

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

There was no activity during the quarter within level 2 of the fair value hierarchy.

Level 3

Included within level 3 of the fair value hierarchy are the following derivatives:

- Commodity Derivatives: Level 3 commodity derivatives include over-the-counter commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on either an indicative broker or dealer price quotation or a valuation model. Our valuation models utilize inputs such as price, volatility and correlation but do not involve significant management judgments.
- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps and treasury locks. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward LIBOR curves and forward treasury yields that are obtained from pricing services.
- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates that are obtained from pricing services.

The majority of our level 3 derivatives are classified as such because the broker or dealer price quotations used to measure fair value and the pricing services used to corroborate the quotations are indicative quotations rather than quotations whereby the broker or dealer is ready and willing to transact. However, the fair value of these level 3 derivatives is not based upon significant management assumptions or subjective inputs.

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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,		Six Months Ended June 30,	
	2010	2009	2010	2009
Beginning Balance	$ (5)	$ 26	$ (28)	$ 74
Unrealized gains/(losses):				
Included in earnings [1]	5	8	12	54
Included in other comprehensive income	1	(21)	1	(22)
Settlements and derivatives entered into during the period	7	(18)	23	(111)
Ending Balance	$ 8	$ (5)	$ 8	$ (5)
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 10	$ (8)	$ 9	$ (8)

(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.

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 10—Commitments and Contingencies

Litigation

Pipeline Releases. In early January 2005, an overflow from a temporary storage tank located in East Texas resulted in the release of approximately 1,200 barrels of crude oil, a portion of which reached the Sabine River. In late December 2004, one of our pipelines in West Texas experienced a rupture that resulted in the release of approximately 4,500 barrels of crude oil, a portion of which reached a remote location of the Pecos River. Approximately 980 and 4,200 barrels were recovered from the two respective sites. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $5 million to $6 million. The EPA has referred these two crude oil releases, as well as several other smaller releases, to the DOJ for further investigation in connection with a civil penalty enforcement action under the Federal Clean Water Act. We have cooperated in the investigation and are currently involved in settlement discussions with DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency (which is included in the estimated aggregate costs set forth above) and have incorporated into our budget process the projected costs associated with potential injunctive remedies. We understand that the maximum permissible penalty, if any, that EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

SemCrude L.P., et al — Debtors (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. In addition, certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to setoff certain of our payables to the debtor against our receivables from the debtor. Certain SemCrude creditors 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 sold the oil to subsequent purchasers such as us. On May 29, 2009, we filed a complaint for declaratory relief to resolve these claims. Certain of these actions have been removed to federal court and transferred to the U.S. Bankruptcy Court in Delaware. We will seek the same procedure with respect to all such actions so that they may be consolidated with our declaratory relief action in Bankruptcy Court. The aggregate amount subject to challenge is approximately $23 million. We intend to vigorously defend our contractual and statutory rights.

On November 15, 2006, we completed the Pacific merger. The following is a summary of the more significant matters that relate to Pacific, its assets or operations.

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 PAT facility at Paulsboro, New Jersey. We estimate that the maximum potential cost to effectively remediate ranges up to $10 million although the NJDEP is asserting a much larger expenditure. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and/or GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific's purchase of the facility. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

NJDEP v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX, Exxon and PAT to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PAT, seeking indemnity and contribution. NJDEP environmental consultants have asserted a clean-up expense that is significantly larger than our estimate.

EPA v. RMPS. 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. These activities, performed at the request of customers, included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA's investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the CAA related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. EPA has referred the matter to DOJ. We continue to engage in discussion with EPA, and to emphasize those factors that should mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have now been filed.

Other Pacific-Legacy Matters. At the time of its merger with Plains, Pacific had completed a number of acquisitions that had not been fully integrated into its operations. Accordingly, we have and may become aware of various instances in which some of these operations may not have been fully compliant with applicable environmental and safety regulations. Although we have been working to bring all of these operations into compliance with applicable requirements, any past noncompliance could result in the imposition of fines, penalties or corrective action requirements by governmental entities. Although we believe that our operations are presently in material compliance with applicable requirements, 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 that may have occurred.

General. We, in the ordinary course of business, are a claimant and/or a defendant 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.

Environmental

Although we believe that our efforts to enhance our leak prevention and detection capabilities have produced positive results, we have experienced (and likely will experience future) releases of hydrocarbon products into the environment from our pipeline and storage operations. These releases can result from unpredictable man-made or natural forces and may reach “navigable waters” or other sensitive environments. For example, when the area around Lubbock, Texas received an unusually heavy rainfall in early July 2010, a branch of the Brazos River became swollen beyond flood stage. The unusually erosive power of the water undercut existing river banks and caused them to collapse. This phenomenon occurred at a river crossing for one of our 4-inch gathering lines. The combined force of the shifting mass of earth and rushing water severed the pipe, apparently allowing the release of crude oil into the river. We estimate that a maximum of 165 barrels may have been released. We also may discover environmental impacts from past releases that were previously unidentified. Whether current or past, damages and liabilities associated with any such releases from our assets may substantially affect our business.

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 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. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations. See “—Pipeline Releases” above.

At June 30, 2010, our reserve for environmental liabilities totaled approximately $61 million, of which approximately $9 million is classified as short-term and $52 million is classified as long-term. At June 30, 2010, we have recorded receivables totaling approximately $5 million for amounts that are 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 known facts and believed to be relevant at the time 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.

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. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 11—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, 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 of unconsolidated entities	$ 1	$ —	$ —	$ 1
Segment profit [(2)] [(3)]	$ 130	$ 70	$ 57	$ 257
Maintenance capital	$ 15	$ 5	$ 2	$ 22
Three Months Ended June 30, 2009				
Revenues:				
External Customers	$ 130	$ 53	$ 4,099	$ 4,282
Intersegment [(1)]	108	32	—	$ 140
Total revenues of reportable segments	$ 238	$ 85	$ 4,099	$ 4,422
Equity earnings of unconsolidated entities	$ 2	$ 3	$ —	$ 5
Segment profit [(2)] [(3)]	$ 114	$ 52	$ 78	$ 244
Maintenance capital	$ 16	$ 3	$ 3	$ 22

	Transportation	Facilities	Supply & Logistics	Total
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 of unconsolidated entities	$ 2	$ —	$ —	$ 2
Segment profit [(2)] [(3)]	$ 257	$ 129	$ 150	$ 536
Maintenance capital	$ 22	$ 8	$ 3	$ 33
Six Months Ended June 30, 2009				
Revenues:				
External Customers	$ 254	$ 100	$ 7,231	$ 7,585
Intersegment [(1)]	210	62	—	$ 272
Total revenues of reportable segments	$ 464	$ 162	$ 7,231	$ 7,857
Equity earnings of unconsolidated entities	$ 3	$ 5	$ —	$ 8
Segment profit [(2)] [(3)]	$ 226	$ 98	$ 238	$ 562
Maintenance capital	$ 30	$ 10	$ 4	$ 44

(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 2009 Annual Report on Form 10-K.

(2) Supply and logistics segment profit includes interest expense on contango inventory purchases of $5 million and $3 million for the three months ended June 30, 2010 and 2009, respectively, and $8 million and $5 million for the six months ended June 30, 2010 and 2009, respectively.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2010	2009	2010	2009
Segment profit	$ 257	$ 244	$ 536	$ 562
Depreciation and amortization	(64)	(56)	(131)	(114)
Interest expense	(62)	(56)	(120)	(107)
Other income, net	2	2	(1)	5
Income tax benefit	—	2	—	1
Net income	133	136	284	347
Less: Net income attributable to noncontrolling interests	(2)	—	(2)	—
Net income attributable to Plains	$ 131	$ 136	$ 282	$ 347

Note 12—Supplemental Condensed Consolidating Financial Information

For purposes of this Note 12, Plains is referred to as "Parent." See Note 13 to our Consolidated Financial Statements included in Part IV of our 2009 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, 2009.

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 Sheet

	As of June 30, 2010				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,935	$ 3,693	$ 255	$ (3,385)	$ 3,498
Property, plant and equipment, net	—	4,643	1,767	—	6,410
Other assets, net	6,022	3,949	369	(7,880)	2,460
Total assets	$ 8,957	$ 12,285	$ 2,391	$ (11,265)	$ 12,368
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 402	$ 6,060	$ 299	$ (3,384)	$ 3,377
Long-term debt	4,140	6	209	(5)	4,350
Other long-term liabilities	—	223	3	—	226
Total liabilities	4,542	6,289	511	(3,389)	7,953
Partners' capital excluding noncontrolling interests	4,184	5,933	1,880	(7,813)	4,184
Noncontrolling interests	231	63	—	(63)	231
Total partners' capital	4,415	5,996	1,880	(7,876)	4,415
Total liabilities and partners' capital	$ 8,957	$ 12,285	$ 2,391	$ (11,265)	$ 12,368

	As of December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,428	$ 3,831	$ 209	$ (3,810)	$ 3,658
Property, plant and equipment, net	—	4,606	1,734	—	6,340
Other assets, net	5,324	3,994	367	(7,325)	2,360
Total assets	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 456	$ 6,849	$ 287	$ (3,810)	$ 3,782
Long-term debt	4,137	15	450	(460)	4,142
Other long-term liabilities	—	271	4	—	275
Total liabilities	4,593	7,135	741	(4,270)	8,199
Partners' capital excluding noncontrolling interest	4,096	5,233	1,569	(6,802)	4,096
Noncontrolling interest	63	63	—	(63)	63
Total partners' capital	4,159	5,296	1,569	(6,865)	4,159
Total liabilities and partners' capital	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358

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Condensed Consolidating Statements of Operations

	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 expense	(62)	3	(3)	—	(62)
Other income, net	—	2	—	—	2
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

	Three Months Ended June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$ —	$ 416	$ 37	$ —	$ 453
Field operating costs	—	(150)	(10)	—	(160)
General and administrative expenses	—	(51)	(3)	—	(54)
Depreciation and amortization	(1)	(48)	(7)	—	(56)
Operating income/(loss)	(1)	167	17	—	183
Equity earnings in unconsolidated entities	194	19	—	(208)	5
Interest expense	(57)	1	—	—	(56)
Other income, net	—	2	—	—	2
Income tax expense	—	2	—	—	2
Net income	$ 136	$ 191	$ 17	$ (208)	$ 136

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Condensed Consolidating Statements of Operations (continued)

	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 expense	(125)	11	(6)	—	(120)
Other income, net	—	(1)	—	—	(1)
Net income	284	412	34	(446)	284
Less: Net income attributable to the noncontrolling interests	(2)	(1)	—	1	(2)
Net income attributable to Plains	$ 282	$ 411	$ 34	$ (445)	$ 282

	Six Months Ended June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 900	$ 66	$ —	$ 966
Field operating costs	—	(293)	(19)	—	(312)
General and administrative expenses	—	(95)	(5)	—	(100)
Depreciation and amortization	(2)	(99)	(13)	—	(114)
Operating income/(loss)	(2)	413	29	—	440
Equity earnings in unconsolidated entities	458	31	—	(481)	8
Interest expense	(109)	2	—	—	(107)
Other income, net	—	5	—	—	5
Income tax expense	—	1	—	—	1
Net income	$ 347	$ 452	$ 29	$ (481)	$ 347

[1] Net operating revenues are calculated as “Total revenues” less “Purchases and related costs”.

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Condensed Consolidating Statements of Cash Flows

	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 (used in) operating activities:					
Depreciation and amortization	2	106	23	—	131
Equity compensation charge	—	32	1	—	33
Equity earnings in unconsolidated subsidiaries, net of distributions	(411)	(34)	—	446	1
Gain on sale of linefill	—	(17)	—	—	(17)
Inventory valuation adjustment	—	3	—	—	3
Other	3	1	—	—	4
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		(153)	—	—	(153)
Additions to property, equipment and other	—	(159)	(56)	—	(215)
Cash received for sale of non-controlling interest in a subsidiary	268	—	—	—	268
Contingent consideration paid	(20)	(11)	—	—	(31)
Net cash received (paid) for linefill in assets owned	—	19	(1)	—	18
Proceeds from the sale of assets and other	—	3	—	—	3
Net cash used in investing activities	248	(301)	(57)	—	(110)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on Plains revolving credit facility	(36)	(114)	—	—	(150)
Net borrowings on PNG revolving credit facility	—	—	205	—	205
Net repayments on short-term letter of credit and hedged inventory facility	—	100	—	—	100
Distributions paid to common unitholders and general partner	(335)	—	—	—	(335)
Other financing activities	(2)	—	—	—	(2)
Net cash provided by (used in) financing activities	(373)	(14)	205	—	(182)
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

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Condensed Consolidating Statements of Cash Flows (continued)

	Six Months Ended June 30, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 347	$ 452	$ 29	$ (481)	$ 347
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	2	99	13	—	114
Equity compensation expense	—	30	—	—	30
Other	(454)	(28)	—	481	(1)
Changes in assets and liabilities, net of acquisitions	4	(176)	(31)	—	(203)
Net cash provided by/(used in) operating activities	(101)	377	11	—	287
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	—	(56)	—	—	(56)
Additions to property, equipment and other	—	(219)	(9)	—	(228)
Investments in unconsolidated entities	(5)	—	—	—	(5)
Cash received for sale of noncontrolling interest in a subsidiary	—	26	—	—	26
Proceeds from the sale of assets and other	—	10	—	—	10
Net cash used in investing activities	(5)	(239)	(9)	—	(253)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility	(158)	(301)	—	—	(459)
Net borrowings on short-term letter of credit and hedged inventory facility	—	157	—	—	157
Net proceeds from the issuance of senior notes	350				350
Net proceeds from the issuance of common units	210	—	—	—	210
Distributions paid to common unitholders and general partner	(291)				(291)
Other financing activities	(5)	—	—	—	(5)
Net cash provided by/(used in) financing activities	106	(144)	—	—	(38)
Net increase/(decrease) in cash and cash equivalents	—	(6)	2	—	(4)
Cash and cash equivalents, beginning of period	2	9	—	—	11
Cash and cash equivalents, end of period	$ 2	$ 3	$ 2	$ —	$ 7

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

Introduction

The following discussion is intended to provide investors with an understanding of our financial condition and results of our operations and should be read in conjunction with our historical consolidated financial statements and accompanying notes and Management's Discussion and Analysis of Financial Condition and Results of Operations as presented in our 2009 Annual Report on Form 10-K. For more detailed information regarding the basis of presentation for the following financial information, see the "Notes to the Condensed Consolidated Financial Statements."

Executive Summary

We provide transportation, storage, terminalling, supply and logistics services with respect to crude oil, refined products and LPG. We are also engaged 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.

Our discussion and analysis herein includes the following:

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

Acquisitions and Internal Growth Projects

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

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Acquisition capital [(1)]	$ 153	$ 60
Internal growth projects	163	157
Maintenance capital	33	44
Investment in unconsolidated entities	—	4
Total	$ 349	$ 265

(1) In the second quarter of 2010, we entered into agreements to purchase various pipeline assets that will be reflected in our transportation segment. The 2010 amounts include deposits paid on these agreements, which have not closed as of June 30, 2010 and are classified as other, net assets within our condensed consolidated balance sheet.

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Our internal growth projects primarily relate to the construction and expansion of pipeline systems, crude oil storage and terminal facilities and natural gas storage facilities. The following table summarizes our more notable projects in progress during 2010 and the forecasted expenditures for the year (in millions):

Projects	2010
PAA Natural Gas Storage	$ 95
Patoka Phase III	18
West Texas gathering lines	18
Cushing - Phase VII	17
Edmonton land purchase	16
St. James - Phase III	15
Cushing - Phase VIII	15
Wichita Falls tanks	11
Other projects [1]	155
	360
Maintenance capital	85
Total Projected Capital Expenditures (excluding acquisitions)	$ 445

(1) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2009.

Results of Operations

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. In order to evaluate segment performance, management focuses on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital. See Note 15 to our Consolidated Financial Statements included in Part IV of our 2009 Annual Report on Form 10-K for further discussion on how we evaluate segment performance.

The following table reflects our segment profit, net income and applicable earnings per limited partner unit for the three and six months ended June 30, 2010 and 2009 (in millions, except per unit amounts):

	Three Months Ended June 30,		Three Months Favorable/ (Unfavorable) Variance		Six Months Ended June 30,		Six Months Favorable/ (Unfavorable) Variance	
	2010	2009	$	%	2010	2009	$	%
Transportation segment profit	$ 130	$ 114	$ 16	14%	$ 257	$ 226	$ 31	14%
Facilities segment profit	70	52	18	35%	129	98	31	32%
Supply & Logistics segment profit	57	78	(21)	(27)%	150	238	(88)	(37)%
Total segment profit	257	244	13	5%	536	562	(26)	(5)%
Depreciation and amortization	(64)	(56)	(8)	(14)%	(131)	(114)	(17)	(15)%
Interest expense	(62)	(56)	(6)	(11)%	(120)	(107)	(13)	(12)%
Other income, net	2	2	—	—%	(1)	5	(6)	(120)%
Income tax expense	—	2	2	100%	—	1	1	100%
Net income	133	136	(3)	(2)%	284	347	(63)	(18)%
Less: Net income attributable to noncontrolling interests	(2)	—	(2)	N/A	(2)	—	(2)	N/A
Net income attributable to Plains	$ 131	$ 136	$ (5)	(4)%	$ 282	$ 347	$ (65)	(19)%
Earnings per basic limited partner unit	$ 0.65	$ 0.79	$ (0.14)	(18)%	$ 1.45	$ 2.20	$ (0.75)	(34)%
Earnings per diluted limited partner unit	$ 0.65	$ 0.78	$ (0.13)	(17)%	$ 1.45	$ 2.18	$ (0.73)	(33)%
Basic weighted average units outstanding	136	129	7	5%	136	126	10	8%
Diluted weighted average units outstanding	137	130	7	5%	137	127	10	8%

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Analysis of Operating Segments

Transportation Segment

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

Operating Results (1) (in millions, except per barrel amounts)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Three Months Favorable/(Unfavorable) Variance $	Three Months Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Six Months Favorable/(Unfavorable) Variance $	Six Months Favorable/(Unfavorable) Variance %
Revenues (1)								
Tariff activities	$ 232	$ 214	$ 18	8%	$ 456	$ 416	$ 40	10%
Trucking	27	24	3	13%	53	48	5	10%
Total transportation revenues	259	238	21	9%	509	464	45	10%
Costs and Expenses (1)								
Trucking costs	(18)	(16)	(2)	(13)%	(35)	(32)	(3)	(9)%
Field operating costs (excluding equity compensation expense)	(88)	(86)	(2)	(2)%	(170)	(163)	(7)	(4)%
Equity compensation expense — operations (2)	(2)	(2)	—	—%	(4)	(4)	—	—%
Segment G&A expenses (excluding equity compensation expense)	(17)	(14)	(3)	(21)%	(33)	(30)	(3)	(10)%
Equity compensation expense—general and administrative (2)	(5)	(8)	3	38%	(12)	(12)	—	—%
Equity earnings in unconsolidated entities	1	2	(1)	(50)%	2	3	(1)	(33)%
Segment profit	$ 130	$ 114	$ 16	14%	$ 257	$ 226	$ 31	14%
Maintenance capital	$ 15	$ 16	$ 1	6%	$ 22	$ 30	$ 8	27%
Segment profit per barrel	$ 0.46	$ 0.41	$ 0.05	12%	$ 0.48	$ 0.42	$ 0.06	14%

Average Daily Volumes (in thousands of barrels per day) (3)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Three Months Favorable/(Unfavorable) Variance Volumes	Three Months Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Six Months Favorable/(Unfavorable) Variance Volumes	Six Months Favorable/(Unfavorable) Variance %
Tariff activities								
All American	43	42	1	2%	41	39	2	5%
Basin	369	440	(71)	(16)%	363	417	(54)	(13)%
Capline	246	204	42	21%	203	205	(2)	(1)%
Line 63/Line 2000	112	145	(33)	(23)%	111	133	(22)	(17)%
Salt Lake City Area Systems	136	139	(3)	(2)%	132	121	11	9%
West Texas/New Mexico Area Systems	387	374	13	3%	376	384	(8)	(2)%
Manito	60	61	(1)	(2)%	60	63	(3)	(5)%
Rainbow	198	181	17	9%	195	188	7	4%
Rangeland	54	53	1	2%	51	56	(5)	(9)%
Refined products	126	91	35	38%	121	94	27	29%
Other	1,256	1,260	(4)	—%	1,193	1,201	(8)	(1)%
Tariff activities total	2,987	2,990	(3)	—%	2,846	2,901	(55)	(2)%
Trucking	95	84	11	13%	92	86	6	7%
Transportation segment total	**3,082**	**3,074**	**8**	**—%**	**2,938**	**2,987**	**(49)**	**(2)%**

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

(2) Equity compensation expense related to our equity compensation plans. See Note 8 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.

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

As noted in the table above, our transportation segment revenues increased for the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009, while volumes remained relatively consistent over these comparative periods. The significant variances between the comparative periods are discussed below:

- Foreign Currency Impact - Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, were translated at the prevailing average exchange rate for each month. During 2010, revenues from some of our Canadian pipeline systems were favorably impacted by the depreciation of the U.S. dollar relative to the Canadian dollar. The average Canadian dollar to U.S. dollar exchange rate for the three-month period ended June 30, 2010 was $1.03 CAD: $1.00 USD compared to an average of $1.17 CAD: $1.00 USD for the three-month period ended June 30, 2009. The average Canadian dollar to U.S. dollar exchange rate for the six-month period ended June 30, 2010 was $1.03 CAD: $1.00 USD compared to an average of $1.21 CAD: $1.00 USD for the six-month period ended June 30, 2009.
- Tariff Rates - Tariff rates increased on some of our pipeline systems during the second half of 2009 as a result of indexing by the FERC. In addition, we had similar type rate increases on some non-FERC regulated pipelines.
- 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 decreased by approximately $6 million for the three months ended June 30, 2010 compared to the three months ended June 30, 2009. The decrease was primarily due to variance in volumes for the three months ended June 30, 2010 compared to the three months ended June 30, 2009. The loss allowance revenue increased by approximately $4 million for the six months ended June 30, 2010 compared to the six months ended June 30, 2009. The increase was primarily due to a higher average realized price per barrel for the six months ended June 30, 2010 compared to the six months ended June 30, 2009 (including the impact of gains and losses from derivative activities).

Field Operating Costs. Field operating costs (excluding equity compensation charges) increased in the three and six months ended June 30, 2010 over the three and six months ended June 30, 2009 primarily due to an approximately $6 million unfavorable foreign currency impact.

Ge*neral and Administrative Expenses*. General and administrative expenses (excluding equity compensation charges as discussed below) increased in the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009 primarily due to foreign currency impact.

Maintenance Capital. The decrease in maintenance capital in the six months ended June 30, 2010 over the six months ended June 30, 2009 is primarily due to (i) increased investment in 2009 applicable to API 653 repairs in an effort to meet our May 2009 compliance deadline and (ii) timing of various repair projects during each year.

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Facilities Segment

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

Operating Results (in millions, except per barrel amounts)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Three Months Favorable/(Unfavorable) Variance $	Three Months Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Six Months Favorable/(Unfavorable) Variance $	Six Months Favorable/(Unfavorable) Variance %
Storage and terminalling revenues [1]	$ 121	$ 85	$ 36	42%	$ 235	$ 162	$ 73	45%
Storage related costs (natural gas related)	(5)	—	(5)	N/A	(12)	—	(12)	N/A
Field operating costs	(34)	(27)	(7)	(26)%	(68)	(54)	(14)	(26)%
Equity compensation charge - operations [2]	—	—	—	N/A	(1)	—	(1)	N/A
Segment G&A expenses (excluding equity compensation expense)	(9)	(6)	(3)	(50)%	(20)	(11)	(9)	(82)%
Equity compensation charge - general and administrative [2]	(3)	(3)	—	—%	(5)	(4)	(1)	(25)%
Equity earnings in unconsolidated entities	—	3	(3)	(100)%	—	5	(5)	(100)%
Segment profit	$ 70	$ 52	$ 18	35%	$ 129	$ 98	$ 31	32%
Maintenance capital	$ 5	$ 3	$ (2)	(67)%	$ 8	$ 10	$ 2	20%
Segment profit per barrel	$ 0.34	$ 0.29	$ 0.05	17%	$ 0.32	$ 0.28	$ 0.04	14%

Volumes [3][4][5]	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Three Months Favorable/(Unfavorable) Variance Volumes	Three Months Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Six Months Favorable/(Unfavorable) Variance Volumes	Six Months Favorable/(Unfavorable) Variance %
Crude oil, refined products and LPG storage (average monthly capacity in millions of barrels)	61	56	5	9%	60	55	5	9%
Natural gas storage (average monthly capacity in billions of cubic feet)	49	20	29	145%	45	18	27	150%
LPG processing (average throughput in thousands of barrels per day)	14	17	(3)	(18)%	13	16	(3)	(19)%
Facilities segment total (average monthly capacity in millions of barrels)	70	60	10	17%	68	59	9	15%

(1) Includes intersegment amounts.

(2) Equity compensation expense related to our equity compensation plans. See Note 8 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 months we actually owned the assets divided by the number of months in the period.

(4) Facilities total calculated as the sum of: (i) crude oil, refined products and LPG storage capacity; (ii) natural gas storage capacity divided by 6 to account for the 6:1 mcf of gas to crude oil barrel ratio; and (iii) LPG processing volumes multiplied by the number of days in the period and divided by the number of months in the period.

(5) In September 2009, we acquired the remaining 50% indirect interest in PNGS, which resulted in our 100% ownership of the natural gas storage business and related operating entities. Therefore, natural gas storage volumes for January through June 2009 are netted to our 50% interest in PNGS. January through June 2010 volumes represent our 100% interest in PNGS.

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

As noted in the table above, our facilities segment revenues (less storage related costs) and volumes increased for the three and six months ended June 30, 2010 over the three and six months ended June 30, 2009. The significant variances in revenues and average monthly volumes between the comparative periods are discussed below:

- Acquisitions — Revenues net of storage related costs and volumes for the three and six months ended June 30, 2010 over the three and six months ended June 30, 2009 were primarily impacted by the PNGS acquisition, which closed during the third quarter of 2009. This acquisition and ongoing expansion activities at PNGS contributed approximately $16 million and $30 million of additional net revenue and approximately 30 Bcf and 27 Bcf of additional natural gas storage capacity for the three and six months ended June 30, 2010, respectively, compared to the corresponding periods during 2009. Revenues were also favorably impacted by the acquisition of a natural gas processing business, which closed during the second quarter of 2009. This acquisition contributed approximately $3 million and $7 million in additional revenue for the three and six months ended June 30, 2010, respectively.
- Expansion Projects — Expansion projects that were completed in phases throughout 2009 also favorably impacted revenues and volumes during the comparative periods. These expansion projects, which were completed at some of our major terminal locations, increased our revenues by a combined $4 million and $6 million, respectively for the first three and six months 2010, compared to the same time period of the prior year. Aggregate volumes increased by approximately 4 million barrels and 5 million barrels for the first six months of 2010 at these facilities.
- Other — During the three and six months ended June 30, 2010, we recognized approximately $3 million and $7 million related to volumetric gains. Volumetric gains were immaterial for the three and six months ended June 30, 2009.

Field Operating Costs. Field operating costs (excluding equity compensation charges) increased in most categories during the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009 primarily due to (i) our continued growth through additional tankage placed into service during 2009 and 2010 at some of our major terminal locations and (ii) acquisitions such as the PNGS and natural gas processing acquisitions completed in second and third quarters of 2009. The consolidation of PNGS into our financial statements following the acquisition in September 2009 resulted in an increase of operating expenses of approximately $2 million and $4 million for the three and six months ended June 30, 2010.

General and Administrative Expenses. Our general and administrative expenses (excluding equity compensation charges) increased during the three and six months ended June 30, 2010 over the three and six months ended June 30, 2009 primarily due to our continued growth through expansions and acquisitions, such as the PNGS and natural gas processing acquisitions completed in 2009. The consolidation of PNGS into our financial statements following the acquisition in September 2009 resulted in an increase of general and administrative expenses of approximately $4 million and $8 million for the three and six months ended June 30, 2010. These costs include approximately $2 million of costs associated with acquisition evaluation, the start-up of the PNG commercial optimization group and other costs associated with the initial public offering efforts.

Equity Earnings in Unconsolidated Entities. Equity earnings in unconsolidated entities decreased in the three and six months ended June 30, 2010 over the three and six months ended June 30, 2009 due to the PNGS acquisition in September 2009 that increased our interest from 50% to 100%.

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Supply and Logistics Segment

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

Operating Results [1] (in millions, except per barrel amounts)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Three Months Favorable/(Unfavorable) Variance $	Three Months Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Six Months Favorable/(Unfavorable) Variance $	Six Months Favorable/(Unfavorable) Variance %
Revenues	$ 5,901	$ 4,099	$ 1,802	44%	$ 11,814	$ 7,231	$ 4,583	63%
Purchases and related costs [2]	(5,773)	(3,951)	(1,822)	(46)%	(11,522)	(6,854)	(4,668)	(68)%
Field operating costs	(49)	(47)	(2)	(4)%	(94)	(96)	2	2%
Equity compensation charge - operation [3]	—	—	—	N/A	(1)	—	(1)	N/A
Segment G&A expenses (excluding equity compensation expense)	(18)	(17)	(1)	(6)%	(37)	(33)	(4)	(12)%
Equity compensation expense - general and administrative [3]	(4)	(6)	2	33%	(10)	(10)	—	—%
Segment profit	$ 57	$ 78	$ (21)	(27)%	$ 150	$ 238	$ (88)	(37)%
Maintenance capital	$ 2	$ 3	$ 1	33%	$ 3	$ 4	$ 1	25%
Segment profit per barrel [4]	$ 0.80	$ 1.11	$ (0.31)	(28)%	$ 1.01	$ 1.60	$ (0.59)	(37)%

Average Daily Volumes [5] (in thousands of barrels per day)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Three Months Favorable/(Unfavorable) Variance Volumes	Three Months Favorable/(Unfavorable) Variance %	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009	Six Months Favorable/(Unfavorable) Variance Volumes	Six Months Favorable/(Unfavorable) Variance %
Crude oil lease gathering purchases	620	623	(3)	—%	611	627	(16)	(3)%
LPG sales	54	60	(6)	(10)%	94	102	(8)	(8)%
Waterborne foreign crude oil imported	74	57	17	30%	73	57	16	28%
Refined products sales	42	36	6	17%	41	36	5	14%
Supply & Logistics segment total	790	776	14	2%	819	822	(3)	—%

(1) Revenues and costs include intersegment amounts.

(2) Purchases and related costs include interest expense (related to hedged inventory purchases) of approximately $5 million and $8 million for the three and six months ended June 30, 2010, respectively, compared to $3 million and $5 million for the three and six months ended June 30, 2009, respectively.

(3) Equity compensation expense related to our equity compensation plans. See Note 8 to our Condensed Consolidated Financial Statements for additional discussion of our equity compensation plans.

(4) Calculated based on crude oil lease gathering purchased volumes, refined products volumes, LPG sales volumes and waterborne foreign crude oil imported volumes.

(5) 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.

The absolute amount of our revenues and purchases increased in the three and six months ended June 30, 2010 as compared to the three and six months ended June 30, 2009, primarily resulting from higher commodity prices experienced in the 2010 period. The NYMEX benchmark price of crude oil ranged from $64 to $87 per barrel and $45 to $73 per barrel during the three months ended June 30, 2010 and 2009, respectively, and from $64 to $87 per barrel and $34 to $73 per barrel during the six months ended June 30, 2010 and 2009, 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.

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. In addition, 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 six-month peak heating season of October through March, and temperature differences from year to year may have a significant effect on financial performance.

Average daily crude oil lease gathering volumes decreased by approximately 16,000 barrels per day during the six months ended June 30, 2010 compared to the same period of 2009 primarily due to the elimination of some of our less profitable lease gathering purchases. Revenues, net of purchases and related costs, decreased by approximately $20 million or 14% and $85 million or 23% during the three and six months ended June 30, 2010 as compared to the three and six months ended June 30, 2009, respectively. Such decrease was primarily due to the following:

For the three month period, revenues, net of purchases and related costs were lower primarily due to a 10% decrease in LPG volumes and a decrease in LPG margins. The margin decrease is due to lower iso-butane margins and the contract mix of customer liftings during the quarter. For the six month period the revenues, net of purchases and related costs were lower due to a combination of (i) 8% lower LPG volumes and margins, particularly iso-butane margins, (ii) less favorable crude oil quality differentials and (iii) less favorable contango market conditions.

Our results were favorably impacted, however, during the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009 as a result of the following:

- Net gains on sales of excess inventory and linefill; and
- Foreign Currency Impact—Revenues and expenses from our Canadian based subsidiaries, which use the Canadian dollar as their functional currency, were translated at the prevailing average exchange rate for each month. During 2010, revenues from some of our Canadian activities were favorably impacted by the depreciation of the USD relative to the CAD. The average CAD to USD exchange rate for the three-month and six-month period ended June 30, 2010 was $1.03 CAD: $1.00 USD and $1.03 CAD: $1.00 USD compared to an average of $1.17 CAD: $1.00 USD and $1.21 CAD: $1.00 USD for the three and six-month period ended June 30, 2009, respectively.

General and Administrative Expenses. Our general and administrative expenses (excluding equity compensation charges) increased during the three and six months ended June 30, 2010 over the three and six months ended June 30, 2009 primarily due to increases in payroll costs related to our intersegment allocation and legal fees.

Other Income and Expenses

Depreciation and Amortization. Depreciation and amortization expense increased approximately $8 million and $17 million for the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009, respectively. Such increases were primarily the result of an increased amount of depreciable assets resulting from our acquisition activities including PNGS as well as various internal growth projects. The increase in depreciation expense was partially offset by extensions of the depreciable lives of several of our large storage facilities based on an ongoing internal review.

Interest Expense. Interest expense increased approximately $6 million and $13 million for the three and six months ended June 30, 2010 compared to the three and six months ended June 30, 2009, respectively. This increase is primarily due to the collective issuance of approximately $1.4 billion of senior notes (in April, July and September 2009), which was partially offset by the collective retirement of approximately $425 million of senior notes (in August and October 2009).

Liquidity and Capital Resources

General

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, which consist of our cash flow generated from operations as well as borrowings under our credit facilities. 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, 2010, we had a working capital surplus of approximately $121 million and approximately $1.2 billion of liquidity available to meet our ongoing operational, investing and finance needs as noted below (in millions):

	As of June 30, 2010
Availability under PAA senior unsecured revolving credit facility	$ 874
Availability under PNG senior unsecured revolving credit facility [1]	195
Availability under PAA senior secured hedged inventory facility	100
Cash and cash equivalents	15
Total	$ 1,184

(1) In April 2010, PNG entered into a three year, $400 million senior unsecured revolving credit facility that matures in May 2013. Borrowing capacity under this facility may be limited from time to time due to covenant limitations. See Note 5 to our condensed consolidated financial statements for additional discussion of this credit facility and the "*Sale of Noncontrolling Interest in a Subsidiary*" section of Note 7 for additional discussion regarding PNG.

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 2009 Annual Report on Form 10-K for further discussion regarding risks that may impact our liquidity and capital resources. Usage of the credit facilities is subject to ongoing compliance with covenants. We are currently in compliance with all covenants.

Congress recently 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 the various aspects of the Act have not yet been issued. We are currently reviewing the provisions of this legislation and its potential impact on our business, and 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 2009 Annual Report on Form 10-K.

Net cash flow provided by operating activities for the first six months of 2010 and 2009 was approximately $283 million and approximately $287 million, respectively. The cash provided by operating activities reflects cash generated by our recurring operations, and is also significantly impacted in periods when we are increasing or decreasing the amount of inventory in storage. During the first six months of both 2010 and 2009, 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 have increased our LPG inventory in preparation of the end users' increased demand for heating requirements experienced during the winter months. The net increased levels of inventory were financed through borrowings under our credit facilities as well as through our $500 million senior notes that are being used to supplement capital available from our hedged inventory facility.

Equity and Debt Financing Activities

Our financing activities primarily relate to funding acquisitions and internal capital projects, and short-term working capital and hedged inventory borrowings related to our LPG business and contango market activities. 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 Securities and Exchange Commission 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, 2010, we have $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 July 2010 offering of our $400 million senior notes due September 15, 2015 was conducted under the WKSI Shelf.

Senior Notes. In July 2010, we completed the issuance of $400 million of 3.95% Senior Notes due September 15, 2015. The senior notes were sold at 99.889% of face value. Interest payments are due on March 15 and September 15 of each year, beginning on September 15, 2010. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, which may be reborrowed to fund our ongoing expansion capital program, potential future acquisitions or potential redemption of our outstanding 6.25% senior notes that mature in September 2015.

Credit Facilities. 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 is primarily due to our increased levels of inventory resulting from the favorable contango market structure and funding our capital program.

During the six months ended June 30, 2009, we had net repayments on our revolving credit facilities and our hedged inventory facility of approximately $302 million. These net repayments resulted primarily from (i) sales of LPG inventory that was liquidated during the period, (ii) our March 2009 equity offering and (iii) our April 2009 debt offering. These repayments were partially offset by borrowings on our hedged inventory facility, which resulted from our increased levels of inventory due to the favorable contango market structure.

For further discussion related to our credit facilities and long-term debt, see "Cash Flow from Operations" above and "Liquidity and Capital Resources—Credit Facilities and Long-Term Debt" under Item 7 of our 2009 Annual Report on Form 10-K.

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 "Internal Growth Projects" above and "Acquisitions and Internal Growth Projects" under Item 7 of our 2009 Annual Report on Form 10-K for further discussion for 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 13, 2010, we will pay a quarterly distribution of $0.9425 per limited partner unit. This distribution represented a year-over-year distribution increase of approximately 4.1%. See Note 7 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 2009 Annual Report on Form 10-K for additional discussion of distribution thresholds.

Upon closing of the Pacific, Rainbow and PNGS acquisitions, our general partner agreed to reduce the amounts due as incentive distributions. See Note 7 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 subject to business and operational risks, however, 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

See Note 10 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 three 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. 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 creditworthy entities.

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, 2010 that varied significantly since December 31, 2009 (in millions):

As of June 30, 2010	2010	2011	2012	2013	2014	2015 and Thereafter	Total
Long-term debt and interest payments [1]	$ 134	$ 267	$ 956	$ 474	$ 209	$ 4,933	$ 6,973
Leases [2]	$ 46	$ 64	$ 55	$ 34	$ 23	$ 241	$ 463
Crude oil, refined products and LPG purchases [3]	$ 4,958	$ 1,141	$ 722	$ 408	$ 400	$ 261	$ 7,890

(1) Includes debt service payments, interest payments due on our senior notes and the commitment fee on our revolving credit facility. Although there is an outstanding balance on our revolving credit facility at June 30, 2010, 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 and (v) trucks used in our gathering activities.

(3) Amounts are based on estimated volumes and market prices based on average activity during June 2010. The actual physical volume purchased and actual settlement prices will vary from the assumptions used in the table. Uncertainties involved in these estimates include levels of production at the wellhead, weather conditions, changes in market prices and other conditions beyond our control.

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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, 2010 and December 31, 2009, we had outstanding letters of credit of approximately $103 million and $76 million, respectively.

Off-Balance Sheet Arrangements

We have no significant off-balance sheet arrangements as defined by Item 307 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 2009 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 statements 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;
- 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 power 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;

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- unanticipated changes in crude oil market structure, grade differentials and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations, accounting standards and statements and related interpretations;
- the effects of competition;
- interruptions in service and fluctuations in tariffs or volumes 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;
- 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 2009 Annual Report on Form 10-K. Except as required by applicable securities laws, we do not intend to update these forward-looking statements and information.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The following should be read in conjunction with Quantitative and Qualitative Disclosures About Market Risk included under Item 7A in our 2009 Annual Report on Form 10-K. There have been no material changes in that information other than as discussed below. Also, see Note 9 to our Condensed Consolidated Financial Statements for additional discussion related to derivative instruments and hedging activities.

Commodity Price Risk

The fair value of our open derivatives with commodity price risk and the change in fair value that would be expected from a ten percent price decrease are shown in the table below (in millions):

	Fair Value	Effect of 10% Price Decrease
Crude oil:		
Futures contracts	$ 165	$ 73
Swaps and options contracts	35	$ 15
LPG and other:		
Futures contracts	(1)	$ —
Swaps and options contracts	(6)	$ (1)
Total Fair Value	$ 193	

Item 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We maintain written DCP. The purpose of our DCP is to provide reasonable assurance that (i) information is recorded, processed, summarized and reported in a manner that allows for timely disclosure of such information in accordance with the securities laws and SEC regulations and (ii) 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.

PART II. OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

The information required by this item is included under the caption “Litigation” in Note 10 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 2009 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).
3.9	—	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).
3.10	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	—	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.12	—	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).
3.13	—	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).
3.14	—	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).
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	—	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 61/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed September 28, 2005).
4.20	—	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.21	—	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.22	—	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	—	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed on May 4, 2010).
10.2	—	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed on May 11, 2010).
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, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations, (ii) Condensed Consolidated Balance Sheets, (iii) Condensed Consolidated Statements of Cash Flows, (iv) Condensed Consolidated Statement of Partners' Capital, (v) Condensed Consolidated Statements of Comprehensive Income, (vi) Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

† Filed herewith

** Management compensatory plan or arrangement

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SIGNATURES

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

PLAINS ALL AMERICAN PIPELINE, L.P.

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

Date: August 6, 2010

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

Date: August 6, 2010

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

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	—	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).
3.10	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	—	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.12	—	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).
3.13	—	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).
3.14	—	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).
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	—	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the 61/4% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed September 28, 2005).
4.20	—	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.21	—	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.22	—	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	—	Contribution Agreement dated as of April 29, 2010 by and among PAA Natural Gas Storage, L.P., PNGS GP LLC, Plains All American Pipeline, L.P., PAA Natural Gas Storage, LLC, PAA/Vulcan Gas Storage, LLC, Plains Marketing, L.P. and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed on May 4, 2010).
10.2	—	Omnibus Agreement dated May 5, 2010 by and among Plains All American GP LLC, Plains All American Pipeline, L.P., PNGS GP LLC and PAA Natural Gas Storage, L.P. (incorporated by reference to Exhibit 10.1 to PNG's Current Report on Form 8-K filed on May 11, 2010).
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, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) Condensed Consolidated Statements of Operations, (ii) Condensed Consolidated Balance Sheets, (iii) Condensed Consolidated Statements of Cash Flows, (iv) Condensed Consolidated Statement of Partners' Capital, (v) Condensed Consolidated Statements of Comprehensive Income, (vi) Condensed Consolidated Statement of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Condensed Consolidated Financial Statements, tagged as blocks of text.

† Filed herewith
** Management compensatory plan or arrangement

EXHIBIT 12.1

STATEMENT OF COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in millions)

	Six Months Ended June 30, 2010	Year Ended December 31, 2009	2008	2007	2006	2005
EARNINGS [1]						
Pre-tax income from continuing operations before noncontrolling interest and income from equity investees	$ 282	$572	$430	$ 350	$ 278	$ 216
add: Fixed charges	157	283	264	233	149	92
Distributed income of equity investees	3	7	10	2	1	1
Amortization of capitalized interest	1	1	1	—	—	—
less: Capitalized interest	(9)	(12)	(17)	(14)	(6)	(2)
Total Earnings	$ 434	$851	$688	$ 571	$ 422	$ 307
FIXED CHARGES [1]						
Interest expensed and capitalized [2]	$ 137	$247	$233	$ 220	$ 141	$ 85
Amortization of debt expense	4	7	4	3	3	3
Portion of rent expense related to interest (33.33%)	16	29	27	10	5	4
Total Fixed Charges	$ 157	$283	$264	$ 233	$ 149	$ 92
RATIO OF EARNINGS TO FIXED CHARGES [3]	2.76x	3.0x	2.6x	2.45x	2.83x	3.34x

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" consists of pre-tax income from continuing operations before income from equity investees plus fixed charges (excluding capitalized interest), distributed income of equity investees and amortization of capitalized interest. "Fixed charges" represents interest incurred (whether expensed or capitalized), amortization of debt expense (including discounts and premiums relating to indebtedness) and the portion of rental expense on operating leases deemed to be the equivalent of interest.

(2) Includes interest costs attributable to borrowings for inventory stored in a contango market of $8 million for the six months ended June 30, 2010 and $11 million, $21 million, $44 million, $49 million and $24 million for each of the years ended December 31, 2009, 2008, 2007, 2006, and 2005, respectively.

(3) Ratios may not recalculate due to rounding.

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Greg L. Armstrong, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2010

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER

PLAINS ALL AMERICAN PIPELINE, L.P.

I, Al Swanson, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Plains All American Pipeline, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officers) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 6, 2010

/s/ Al Swanson

Al Swanson
Chief Financial Officer

EXHIBIT 32.1

**CERTIFICATION OF
PRINCIPAL EXECUTIVE OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350**

I, Greg L. Armstrong, Chief Executive Officer of Plains All American Pipeline, L.P. (the "Company"), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended June 30, 2010 and filed with the Securities and Exchange Commission on the date hereof (the "Report") by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ GREG L. ARMSTRONG

Name: Greg L. Armstrong
Date: August 6, 2010

EXHIBIT 32.2

CERTIFICATION OF
PRINCIPAL FINANCIAL OFFICER
OF PLAINS ALL AMERICAN PIPELINE, L.P.
PURSUANT TO 18 U.S.C. 1350

I, Al Swanson, Chief Financial Officer of Plains All American Pipeline, L.P. (the “Company”), hereby certify that:

(i) the accompanying report on Form 10-Q for the period ended June 30, 2010 and filed with the Securities and Exchange Commission on the date hereof (the “Report”) by the Company fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)); and

(ii) the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Al Swanson

Name: Al Swanson
Date: August 6, 2010