PLAINS ALL AMERICAN PIPELINE LP
Form 10-Q
May 06, 2008

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2008

OR

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

Commission file number: 1-14569

PLAINS ALL AMERICAN PIPELINE, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**76-0582150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002

(Address of principal executive offices) (Zip Code)

(713) 646-4100

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

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 definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x   Accelerated Filer o   Non-Accelerated Filer o (Do not check if a smaller reporting company)   Smaller Reporting Company o

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

At May 1, 2008, there were outstanding 115,981,676 Common Units.

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)

	March 31, 2008 (unaudited)	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 17	$ 24
Trade accounts receivable and other receivables, net	2,756	2,561
Inventory	776	972
Other current assets	114	116
Total current assets	3,663	3,673
PROPERTY AND EQUIPMENT	5,051	4,938
Accumulated depreciation	(557)	(519)
	4,494	4,419
OTHER ASSETS		
Pipeline linefill in owned assets	282	284
Inventory in third-party assets	79	74
Investment in unconsolidated entities	227	215
Goodwill	1,071	1,072
Other, net	169	169
Total assets	$ 9,985	$ 9,906
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liablities	$ 2,996	$ 2,577
Short-term debt	700	960
Other current liabilities	169	192
Total current liabilities	3,865	3,729
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	13	1
Senior notes, net of unamortized net discount of $2 and $2, respectively	2,623	2,623
Other long-term liabilities and deferred credits	154	129
Total long-term liabilities	2,790	2,753
COMMITMENTS AND CONTINGENCIES (NOTE 12)		
PARTNERS CAPITAL		

Common unitholders (115,981,676 units outstanding at March 31, 2008 and December 31, 2007)		3,251		3,343
General partner		79		81
Total partners capital		3,330		3,424
Total liabilities and partners capital	$	9,985	$	9,906

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per unit data)

	Three Months Ended March 31,	
	2008	2007
	(unaudited)	
REVENUES		
Crude oil, refined products and LPG sales and related revenues	$ 7,049	$ 4,117
Pipeline tariff activities revenues	110	87
Other revenues	36	26
Total revenues	7,195	4,230
COSTS AND EXPENSES		
Crude oil, refined products and LPG purchases and related costs	6,836	3,900
Field operating costs	144	125
General and administrative expenses	40	47
Depreciation and amortization	48	40
Total costs and expenses	7,068	4,112
OPERATING INCOME	127	118
OTHER INCOME/(EXPENSE)		
Equity earnings in unconsolidated entities	2	3
Interest expense (net of capitalized interest of $6 and $3)	(42)	(41)
Interest income and other income (expense), net	3	5
Income before tax	90	85
Current income tax expense	(1)	
Deferred income tax benefit	3	
NET INCOME	$ 92	$ 85
NET INCOME-LIMITED PARTNERS	$ 67	$ 68
NET INCOME-GENERAL PARTNER	$ 25	$ 17
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.58	$ 0.62
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.57	$ 0.61
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	116	109
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	117	111

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Three Months Ended March 31, 2008	2007
	(unaudited)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 92	$ 85
Adjustments to reconcile to cash flows from operating activities:		
Depreciation and amortization	48	40
SFAS 133 mark-to-market adjustment	5	17
Inventory valuation adjustment		1
Gain on sale of linefill	(3)	
Gain on sale of investment assets		(4)
Equity compensation charge	6	19
Deferred income tax benefit	(3)	
Gain on foreign currency revaluation	(3)	
Equity earnings in unconsolidated entities, net of distributions	1	(3)
Changes in assets and liabilities, net of acquisitions:		
Trade accounts receivable and other	(229)	61
Inventory	181	323
Accounts payable and other current liabilities	414	(167)
Net cash provided by operating activities	509	372
CASH FLOWS FROM INVESTING ACTIVITIES		
Cash paid in connection with acquisitions (Note 4)		(17)
Additions to property and equipment	(149)	(134)
Investment in unconsolidated entities	(13)	(9)
Cash paid for linefill in assets owned		(4)
Proceeds from sales of assets	10	4
Net cash used in investing activities	(152)	(160)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net repayments on revolving credit facility	(181)	(70)
Net repayments on short-term letter of credit and hedged inventory facility	(62)	(32)
Distributions paid to common unitholders (Note 8)	(99)	(88)
Distributions paid to general partner (Note 8)	(25)	(17)
Net cash used in financing activities	(367)	(207)
Effect of translation adjustment on cash	3	1
Net increase (decrease) in cash and cash equivalents	(7)	6
Cash and cash equivalents, beginning of period	24	11
Cash and cash equivalents, end of period	$ 17	$ 17

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

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in millions)

	Common Units Units	Common Units Amount	General Partner Amount	Partners Capital Amount
		(unaudited)		
Balance at December 31, 2007	**116**	**$ 3,343**	**$ 81**	**$ 3,424**
Net income		67	25	92
Distributions		(99)	(25)	(124)
Class B Units of Plains AAP, L.P.		3		3
Other comprehensive loss		(63)	(2)	(65)
Balance at March 31, 2008	**116**	**$ 3,251**	**$ 79**	**$ 3,330**

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in millions)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
	(unaudited)	
Net income	$ 92	$ 85
Other comprehensive loss	(65)	(14)
Comprehensive income	$ 27	$ 71

CONDENSED CONSOLIDATED STATEMENT OF

CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

(in millions)

	Net Deferred Gain/(Loss) on Derivative Instruments	Currency Translation Adjustments	Total
		(unaudited)	
Balance at December 31, 2007	$ 4	$ 176	$ 180
Reclassification adjustments for settled contracts	(16)		(16)
Changes in fair value of outstanding hedge positions	(21)		(21)
Currency translation adjustment		(28)	(28)

Total period activity		(37)		(28)		(65)
Balance at March 31, 2008	$	(33)	$	148	$	115

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(unaudited)

Note 1 Organization and Accounting Policies

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. a 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.

We are engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas-related petroleum products. We refer to liquefied petroleum gas and other natural gas-related petroleum products collectively as LPG. Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC (PAA/Vulcan), we are also involved in the development and operation of natural gas storage facilities.

Our condensed consolidated interim financial statements should be read in conjunction with our consolidated financial statements and notes thereto presented in our 2007 Annual Report on Form 10-K. The financial statements have been prepared in accordance with the instructions for interim reporting as prescribed by the Securities and Exchange Commission. 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. The results of operations for the three months ended March 31, 2008 should not be taken as indicative of the results to be expected for the full year.

The accompanying condensed consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in 50% or less owned entities over which we have significant influence but not control are accounted for by the equity method. During the first quarter of 2008, we made an additional investment of $13 million in PAA/Vulcan. This investment did not result in an increase in our ownership interest.

Note 2 Recent Accounting Pronouncements

In March 2008, the Emerging Issues Task Force (EITF) issued Issue No. 07-04 (EITF 07-04), *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*. EITF 07-04 addresses the application of the two-class method under Statement of Financial Accounting Standard (SFAS) 128 in determining income per unit for master limited partnerships (MLPs) having multiple classes of securities that may participate in partnership distributions according to a formula specified in the partnership agreement. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating security according to dividends declared (or accumulated) and participation rights in undistributed earnings. EITF 07-04 will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years, and earlier application is not permitted. We are evaluating the impact of adoption of EITF 07-04.

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities including an amendment of SFAS 115* (SFAS 159), which allows entities to choose, at specified election dates, to measure eligible financial assets and financial liabilities at fair value, on an instrument-by-instrument basis, in situations where they are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item s fair value in subsequent reporting periods must be recognized in current earnings. The standard also establishes presentation and disclosure requirements designed to draw comparisons between the different measurement attributes elected for similar types of assets and liabilities. We have adopted SFAS 159 as of the beginning of 2008; however, we have elected not to apply the fair value option to any of our financial assets or liabilities existing at the time of adoption. We will continue to evaluate all new financial assets and liabilities for treatment under SFAS 159.

In September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements* (SFAS 157). SFAS 157 defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. SFAS 157 does not add any new fair value measurements, but it does change current practice and is intended to increase consistency and comparability in such measurements. SFAS 157 also (i) establishes that fair value is based on a hierarchy of inputs into the valuation process, (ii) clarifies that an issuer s credit standing should be considered when measuring liabilities at fair value, (iii) precludes the use of a liquidity or block discount when measuring instruments traded in an actively quoted market at fair value and (iv) requires costs relating to acquiring instruments carried at fair value to be recognized as expense when incurred. SFAS 157 requires that a fair value measurement reflect the assumptions market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risk inherent in a particular valuation technique (such as a pricing model) and the risks inherent in the inputs to the valuation technique.

The provisions of SFAS 157 were deferred for one year for certain non-financial assets and non-financial liabilities, including our asset retirement obligations, goodwill, intangible assets and long-lived assets. We have adopted SFAS 157 as of January 1, 2008 with the exception of those assets and liabilities that are subject to the deferral.

The provisions of SFAS 157 are to be applied prospectively, except for the initial impact of three specific items that are required to be recorded as a transition adjustment to beginning retained earnings in the year of adoption. We did not recognize a transition adjustment because the three specific items were not applicable to us. SFAS 157 also requires new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value. See Note 10 for additional disclosure.

Note 3 Trade Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of refined products and LPG. These purchasers include refineries, marketing and trading companies and financial institutions that are active in the physical and financial commodity markets. The majority of our accounts receivable relate to our marketing activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes. Recent turmoil in the financial markets, which escalated late in the first quarter of 2008, resulted in unprecedented actions by the Federal Reserve Bank to provide liquidity to financial institutions. We believe these conditions, combined with significant energy price volatility, have increased the potential credit risks associated with certain financial institutions and trading companies with which we do business. We closely monitor these conditions and make a determination of the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, advance cash payments or parental guarantees. At March 31, 2008 and December 31, 2007, we had received approximately $49 million and $43 million, respectively, of advance cash payments and prepayments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with most of our counterparties. These arrangements cover a significant portion of our transactions and also serve to mitigate credit risk.

We review all outstanding accounts receivable balances on a monthly basis and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserve until substantially all collection efforts have been exhausted. At March 31, 2008 and December 31, 2007, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date, and our allowance for doubtful accounts receivable totaled approximately $1 million and $1 million, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts may vary significantly from estimated amounts.

Note 4 Acquisitions and Dispositions

We did not complete any acquisitions during the first quarter of 2008. However, during April 2008, we signed a definitive agreement to acquire all of the shares of Rainbow Pipe Line Company, Ltd. (Rainbow) for approximately Canadian $540 million in cash. In conjunction with signing the agreement, we paid a deposit of approximately $54 million. Rainbow s assets include approximately 480 miles of mainline crude oil pipelines, approximately 140 miles of gathering pipelines and approximately 570,000 barrels of tankage along the system. Upon closing, we will also acquire approximately 1 million barrels of crude oil linefill at a value based on crude oil prices at such time. The system currently has a throughput capacity of approximately 200,000 barrels per day and 2007 volumes on the system averaged approximately 195,000 barrels per day. The acquisition is expected to close in the second quarter of 2008 and the acquired operations will be reflected primarily in our transportation segment. The transaction is subject to receipt of regulatory approvals and satisfaction of customary closing conditions.

In anticipation of closing the Rainbow acquisition, we recently entered into forward currency exchange contracts, which exchange Canadian dollars and US dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. Additionally, we entered into a financial option strategy, whereby we established a minimum and maximum per barrel price to hedge the commodity price risk associated with the anticipated purchase of crude oil linefill.

Note 5 Inventory and Linefill

Inventory and linefill consisted of (barrels in thousands and dollars in millions, except per barrel amounts):

	March 31, 2008			December 31, 2007		
	Barrels	Dollars	Dollar/ Barrel (2)	Barrels	Dollars	Dollar/ Barrel (2)
Inventory (1)						
Crude oil	7,235	$ 649	$ 89.70	7,365	$ 592	$ 80.38
LPG	1,779	111	$ 62.39	6,480	363	$ 56.02
Refined products	102	10	$ 98.04	133	11	$ 82.71
Parts and supplies	N/A	6	N/A	N/A	6	N/A
Inventory subtotal	9,116	776		13,978	972	
Inventory in third-party assets						
Crude oil	1,007	68	$ 67.53	986	64	$ 64.91
LPG	175	11	$ 62.86	175	10	$ 57.14
Inventory in third-party assets subtotal	1,182	79		1,161	74	
Pipeline linefill in owned assets						
Crude oil	7,676	280	$ 36.48	7,734	282	$ 36.46
LPG	51	2	$ 39.22	43	2	$ 46.51
Pipeline linefill in owned assets subtotal	7,727	282		7,777	284	
Total	18,025	$ 1,137		22,916	$ 1,330	

(1) Includes the impact of inventory hedges on a portion of our volumes.

(2) The prices listed represent a weighted average associated with various grades and qualities of crude oil, LPG and refined products and, accordingly, are not comparable metrics with published benchmarks for such products.

Note 6 Debt

Debt consisted of the following (in millions):

	March 31, 2008	December 31, 2007
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 3.5% and 5.3% at March 31, 2008 and December 31, 2007, respectively	$ 414	$ 476
Working capital borrowings, bearing interest at a rate of 3.5% and 5.5% at March 31, 2008 and December 31, 2007, respectively (1)	284	482
Other	2	2
Total short-term debt	700	960

Long-term debt:				
Senior notes, net of unamortized net premium and discount		2,623		2,623
Long-term debt under credit facilities and other (1) (2)		13		1
Total long-term debt (1)		2,636		2,624
Total debt	$	3,336	$	3,584

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(1) At March 31, 2008 and December 31, 2007, we have classified as short-term $284 million and $482 million, respectively, of borrowings under our senior unsecured revolving credit facility. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE) margin deposits.

(2) Includes adjustment related to fair value hedge. Fair value hedge accounting was discontinued subsequent to June 30, 2007. The outstanding balance will be amortized over the remaining life of the underlying debt. Also includes the long-term portion of our revolving credit facility borrowings.

In April 2008, we completed the issuance of $600 million of 6.5% Senior Notes due May 1, 2018. The senior notes were sold at 99.424% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2008. We used the net proceeds from the offering to repay amounts outstanding under our credit facilities. We may borrow under our credit facilities to fund our capital program, including the acquisition of Rainbow and other acquisitions, and for general partnership purposes. These notes were co-issued by us and a wholly-owned consolidated finance subsidiary and are guaranteed by substantially all of our subsidiaries other than (i) PAA Finance Corp., the co-issuer of the notes, (ii) subsidiaries that are minor, and (iii) subsidiaries regulated by the California Public Utilities Commission. See Note 14.

Letters of Credit

In connection with our crude oil marketing activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. These letters of credit are issued under our senior unsecured revolving credit facility, and our liabilities with respect to these purchase obligations are recorded in accounts payable on our balance sheet in the month the crude oil is purchased. Generally, these letters of credit are issued for periods of up to seventy days and are terminated upon completion of each transaction. At March 31, 2008 and December 31, 2007, we had outstanding letters of credit of approximately $91 million and $153 million, respectively.

Note 7 Earnings Per Limited Partner Unit

Except as discussed below, basic and diluted net income per limited partner unit is determined by dividing net income after deducting the amount allocated to the general partner (including the incentive distribution interest in excess of the 2% general partner interest) by the weighted average number of outstanding limited partner units during the period. Subject to applicability of EITF Issue No. 03-06 (EITF 03-06), *Participating Securities and the Two-Class Method under FASB Statement No. 128,* as discussed below, Partnership income is first allocated to the general partner based on the amount of incentive distributions. The remainder is then allocated between the limited partners and general partner based on percentage ownership in the Partnership.

EITF 03-06 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF 03-06 provides that in any accounting period during which our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods had been distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results; however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs because a larger portion of our aggregate earnings is allocated (as if distributed) to our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-06 does not have any impact on our earnings per unit calculation. The application of EITF
03-06 had no impact for the three months ended March 31, 2008 or for the three months ended March 31, 2007. Effective January 1, 2009, we will adopt the provisions of EITF 07-04. See Note 2 for further discussion.

The following table sets forth the computation of basic and diluted earnings per limited partner unit. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for the dilutive impact of units outstanding under our long-term incentive plans (LTIP) at March 31, 2008 and 2007 (amounts in millions, except per unit data).

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	Three Months Ended March 31, 2008	2007
Numerator for basic and diluted earnings per limited partner unit:		
Net income	$ 92	$ 85
Less: General partner s incentive distribution paid	(23)	(15)
Subtotal	69	70
Less: General partner 2% ownership	(2)	(2)
Net income available to limited partners	$ 67	$ 68
Denominator:		
Basic weighted average number of limited partner units outstanding	116	109
Effect of dilutive securities:		
Weighted average LTIP units (1)	1	2
Diluted weighted average number of limited partner units outstanding	117	111
Basic net income per limited partner unit	$ 0.58	$ 0.62
Diluted net income per limited partner unit	$ 0.57	$ 0.61

(1) Our LTIP awards described in Note 9 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. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in SFAS No. 128, *Earnings per Share.*

Note 8 Partners Capital and Distributions

Distributions

The following table details the distribution we declared subsequent to the first quarter of 2008 and distributions declared and paid in the three months ended March 31, 2008 and 2007 (in millions, except per unit amounts):

Date Declared	Date Paid or To Be Paid	Common Units	Distributions Paid General Partner Incentive	2%	Total	Distributions per limited partner unit
April 17, 2008	May 15, 2008 (1)	$ 100	$ 25	$ 2	$ 127	$ 0.8650
January 16, 2008	February 14, 2008	$ 99	$ 23	$ 2	$ 124	$ 0.8500
January 16, 2007	February 14, 2007	$ 88	$ 15	$ 2	$ 105	$ 0.8000

(1) Payable to unitholders of record on May 5, 2008, for the period January 1, 2008 through March 31, 2008.

Upon closing of the Pacific acquisition, our general partner agreed to reduce the amounts due it as incentive distributions. The total reduction in incentive distributions related to Pacific will be $65 million. Following the distribution in May 2008, the aggregate remaining incentive distribution reductions related to Pacific will be approximately $38 million.

Note 9 Equity Compensation Plans

Long-Term Incentive Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the 1998 Plan) and the 2005 Long-Term Incentive Plan (the 2005 Plan) for employees and directors, the PPX Successor Long-Term Incentive Plan (the PPX Successor Plan) for former Pacific employees and new hires since the closing of the Pacific acquisition, and the Plains All American GP LLC 2006 Long-Term Incentive Tracking Unit Plan (the 2006 Plan) for non-officer employees. The 1998 Plan, 2005 Plan and PPX Successor Plan authorize the grant of an aggregate of 5.4 million common units deliverable upon vesting. Although other types of awards are contemplated under the plans, currently outstanding awards are limited to phantom units, which mature into the right to receive common units (or cash equivalent) upon vesting. Some awards also include distribution equivalent rights (DERs). Subject to applicable earning criteria, a DER entitles the grantee to a cash payment equal to the cash distribution paid on an outstanding common unit. The 2006 Plan authorizes the grant of approximately 1.4 million tracking units which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a common unit at the time of vesting. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

Under SFAS No. 123(R) *Share Based Payment,* (SFAS 123(R)) the fair value of our LTIP awards, which are subject to liability classification, is calculated based on the closing market price of our units at each balance sheet date adjusted for (i) the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is recognized as compensation expense over the period the awards are earned. Our LTIP awards typically contain performance conditions based on attainment of certain annualized distribution levels, and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions, we recognize compensation expense only if the achievement of the performance condition is considered probable, and amortize that expense over the service period. At the time when performance conditions are first deemed probable of occurring, we incur additional LTIP compensation expense necessary to adjust the life-to-date accrued liability associated with the affected awards. Our DER awards typically contain performance conditions based on attainment of certain annualized distribution levels and become earned upon the earlier of a certain date or the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. We recognize compensation expense for DER payments in the period the payment is earned.

At March 31, 2008 we have the following LTIP awards outstanding (units in millions):

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date 2008	2009	2010	2011	2012
1.3(1)	$ 3.20	0.1	0.6	0.6		
1.2(2)	$ 3.50 - $4.00			0.1	0.7	0.4
1.0(3)	$ 3.50 - $4.00			1.0		
3.5(4)(5)		0.1	0.6	1.7	0.7	0.4

(1) Upon our February 2007 annualized distribution of $3.20, these LTIP awards satisfied all distribution requirements and will vest upon completion of the respective service periods.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained, these awards will be forfeited. The awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00. Fifty percent of these awards will vest in 2012 regardless of whether the performance conditions are attained. The awards are presented above assuming the distribution levels are attained and the early vesting requirements are met.

(4) Approximately 2.1 million of our 3.5 million outstanding LTIP awards also include DERs, of which 1.3 million are currently earned.

(5) LTIP units outstanding do not include Class B units of Plains AAP, L.P. described below.

Our LTIP activity is summarized in the following table (in millions, except weighted average grant date fair values per unit):

	Units		Weighted Average Grant Date Fair Value per Unit
Outstanding at December 31, 2007	3.6	$	37.73
Granted			
Vested			
Cancelled or forfeited	(0.1)	$	39.20
Outstanding at March 31, 2008	3.5	$	37.74

Our accrued liability at March 31, 2008 related to all outstanding LTIP awards and DERs is approximately $52 million, which includes an accrual associated with our assessment that an annualized distribution of $3.50 is probable of occurring. We have not deemed a distribution of more than $3.50 to be probable. At December 31, 2007, the accrued liability was approximately $51 million.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units of Plains AAP, L.P., to be administered by the compensation committee. At March 31, 2008, approximately 154,000 Class B units have been granted and the remaining units are reserved for future grants. The Class B restricted units are earned in 25% increments upon us achieving annualized distribution levels of $3.50, $3.75, $4.00 and $4.50 (or in some cases, within six months thereof). When earned, the Class B units are entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million per quarter. Assuming all 200,000 Class B units were granted and earned, the maximum participation would be 8% of Plains AAP, L.P. s distribution in excess of $11 million each quarter. Although the entire economic burden of the Class B units, which are equity classified, is borne solely by Plains AAP, L.P. and does not impact our cash or units outstanding, the intent of the Class B units is to provide a performance incentive and encourage retention for certain members of our senior management. Therefore, we recognize the grant date fair value of the Class B units as compensation expense over the service period. The expense is also reflected as a capital contribution and results in a corresponding credit to Partners Capital in our Condensed Consolidated Financial Statements. The total grant date fair value of the 154,000 Class B units outstanding at March 31, 2008 was approximately $34 million, of which approximately $3 million was recognized as expense during the three months ended March 31, 2008.

Other Consolidated Information

We refer to our LTIP Plans and the Class B units collectively as our equity compensation plans. The table below summarizes the expense recognized and the value of vestings (settled both in units and cash) related to our equity compensation plans (in millions):

	Three Months Ended March 31, 2008		2007	
Equity compensation expense	$	6	$	19
LTIP unit settled vestings	$		$	
LTIP cash settled vestings	$	1	$	
DER cash payments	$	1	$	1

Based on the March 31, 2008 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $53 million of additional expense over the life of our outstanding awards under our equity compensation plans related to the remaining unrecognized fair value. This estimate is based on the closing market price of our units of $47.54 at March 31, 2008. Actual amounts may differ materially as a result of a change in market price 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 Plan Fair Value Amortization (1)	
2008 (2)	$	21
2009		17
2010		10
2011		3
2012		2
Total	$	53

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at March 31, 2008.

(2) Includes equity compensation plan fair value amortization for the remaining nine months of 2008.

Note 10 Derivative Instruments and Hedging Activities

The derivative instruments we use consist primarily of futures and options contracts traded on the NYMEX, the ICE and over-the-counter, including commodity swap and option contracts entered into with financial institutions and other energy companies.

Summary of Financial Impact

A summary of the earnings impact of all derivative activities, including the change in fair value of open derivatives and settled derivatives recognized in earnings, is as follows (in millions, losses designated in parentheses):

	For the Three Months Ended March 31, 2008			For the Three Months Ended March 31, 2007		
	Mark-to-market, net	Settled	Total	Mark-to-market, net	Settled	Total
Commodity price risk hedging	$ (5)	$ 91	$ 86	$ (19)	$ 70	$ 51
Controlled trading program						
Interest rate risk hedging	2		2			
Currency exchange rate risk hedging	(2)	(2)	(4)	2	(1)	1
Total	$ (5)	$ 89	$ 84	$ (17)	$ 69	$ 52

The breakdown of the net mark-to-market impact to earnings between derivatives that do not qualify for hedge accounting and the ineffective portion of cash flow hedges is as follows (in millions, losses designated in parentheses):

	For the Three Months Ended March 31,	
	2008	2007
Derivatives that do not qualify for hedge accounting	$ (6)	$ (16)
Ineffective portion of cash flow hedges	1	(1)
Total	$ (5)	$ (17)

Derivatives that do not qualify for hedge accounting consist of (i) derivatives that are an effective element of our risk management strategy but are not consistently effective to qualify for hedge accounting pursuant to SFAS No. 133, *Accounting For Derivative Instruments and Hedging Activities,* as amended (SFAS 133) and (ii) certain transactions that have not been designated as hedges.

The following table summarizes the net assets and liabilities on our condensed consolidated balance sheet that are related to the fair value of our open derivative positions (in millions):

	March 31, 2008	December 31, 2007
Other current assets	$ 33	$ 56
Other long-term assets	30	26
Other current liabilities	(90)	(97)
Long-term debt under credit facilities and other (fair value hedge adjustment) (1)	1	1
Other long-term liabilities and deferred credits	(53)	(22)
Net liability	$ (79)	$ (36)

(1) Fair value hedge accounting was discounted for certain interest rate swaps subsequent to June 30, 2007. The related fair value adjustment to the underlying debt will be amortized over the remaining life of the underlying debt.

The net liability related to the fair value of our open derivative positions consists of unrealized gains/losses recognized in earnings and unrealized gains/losses deferred to Accumulated Other Comprehensive Income (AOCI) as follows, by category (in millions, losses designated in parentheses):

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	March 31, 2008			December 31, 2007		
	Net Asset / (Liability)	Earnings	AOCI	Net Asset / (Liability)	Earnings	AOCI
Commodity price risk hedging	$ (76)	$ (53)	$ (23)	$ (38)	$ (48)	$ 10
Controlled trading program						
Interest rate risk hedging (1)	(2)	4	(6)	3	3	
Currency exchange rate risk hedging	(1)	(2)	1	(1)		(1)
	$ (79)	$ (51)	$ (28)	$ (36)	$ (45)	$ 9

(1) Amounts are presented on a net basis and include both the net asset/(liability) related to our interest rate derivatives and any fair value adjustment related to our underlying debt.

In addition to the $28 million of unrealized loss as of March 31, 2008 and the $9 million of unrealized gain as of December 31, 2007 deferred to AOCI for open derivative positions, AOCI also includes deferred losses of approximately $5 million and $5 million as of March 31, 2008 and December 31, 2007, respectively, that relate to terminated interest rate swaps that were cash settled in connection with the issuance and refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the underlying debt.

The total amount of deferred net loss recorded in AOCI is expected to be reclassified to future earnings, contemporaneously with the related physical purchase or delivery of the underlying commodity or payments of interest. Of the total net loss deferred in AOCI at March 31, 2008, a net loss of approximately $28 million will be reclassified into earnings in the next twelve months; the remaining net loss will be reclassified at various intervals (ending in 2016 for amounts related to our terminated interest rate swaps and 2010 for amounts related to our commodity price-risk hedging). Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions. During the three months ended March 31, 2008 and 2007, no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring.

We do not offset the assets and liabilities associated with the fair value of our derivatives with amounts we have recognized related to our right to receive or our obligation to pay cash collateral. When we deposit cash collateral with our brokers, we recognize a broker receivable which is a component of our accounts receivable. We recognized broker receivables of $149 million and $16 million as of March 31, 2008 and December 31, 2007.

In anticipation of closing the Rainbow acquisition, we recently entered into derivative instruments. See Note 4 for further discussion.

Adoption of SFAS 157

Effective January 1, 2008, we adopted SFAS 157 as discussed in Note 2, which, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS 157, fair value is the price that would be received from selling an asset, or paid to transfer a liability, in an orderly transaction between market participants at the measurement date. Whenever possible, we use market data that market participants would use when pricing an asset or liability. These inputs can be readily observable or market corroborated. We apply the market approach for recurring fair value measurements related to our derivatives. SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS 157 are as follows:

Level 1 Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives.

Level 2 Pricing inputs are other than quoted prices in active markets included in level 1, which are either directly or indirectly observable as of the reporting date. If the asset or liability has a specified term, a level 2 input must be observable for substantially the full term of the asset or liability.

Level 3 Pricing inputs include inputs that are unobservable for the asset or liability. Financial instruments that are valued based on a broker quotation are also included in level 3 if the broker quotation is considered to be an indicative quotation rather than a quotation at which the broker is ready and willing to transact.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2008. As required by SFAS 157, 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 and may affect the placement of assets and liabilities within the fair value hierarchy levels.

Recurring Fair Value Measures	**Fair Value as of March 31, 2008 (in millions)**			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
Commodity derivatives	$ 30	$	$ 29	$ 59
Interest rate derivatives			4	4
Foreign currency derivatives				
Total assets at fair value	$ 30	$	$ 33	$ 63
Liabilities:				
Commodity derivatives	$ (67)	$ (12)	$ (56)	$ (135)
Interest rate derivatives			(7)	(7)
Foreign currency derivatives			(1)	(1)
Total liabilities at fair value	$ (67)	$ (12)	$ (64)	$ (143)
Net asset/(liability) at fair value	$ (37)	$ (12)	$ (31)	$ (80)

The determination of the fair values above incorporates various factors required under SFAS 157. These factors include 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. 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 commodity derivatives that are exchange traded. Exchange-traded derivative contracts include futures and exchange-traded options. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy is a physical commodity supply contract that meets the definition of a derivative and is not exempted from SFAS 133 under the normal purchase/normal sale exemption. The fair value of this commodity derivative is measured with level 1 inputs for similar but not identical instruments and therefore must be included in level 2 of the fair value hierarchy.

Level 3

Included within level 3 of the fair value hierarchy are commodity derivatives that are not exchange traded, interest rate derivatives and foreign currency derivatives which are described as follows:

- Commodity Derivatives: Level 3 commodity derivatives include OTC commodity derivatives such as forwards, swaps and options. The fair value of OTC 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 and 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 the derivatives included in level 3 of the fair value hierarchy are classified as level 3 as 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.

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 measured at fair value using inputs classified as level 3 in the fair value hierarchy (in millions).

		Three Months Ended March 31, 2008
Balance as of January 1, 2008	$	(21)
Realized and unrealized gains (losses):		
Included in earnings[1]		(26)
Included in other comprehensive income		(5)
Purchases, issuances, sales and settlements		21
Transfers into or out of level 3[2]		
Balance as of March 31, 2008	$	(31)
Change in unrealized gains (losses) included in earnings relating to level 3 derivatives still held as of March 31, 2008[3]	$	(24)

(1) Gains and losses associated with level 3 commodity derivatives are reported in our condensed consolidated statements of operations as crude oil, refined products and LPG sales or purchases. Unrealized gains and losses associated with interest rate derivatives are reported in our condensed consolidated statements of operations as other income (expense) and realized gains and losses are reported in our condensed consolidated statements of operations as interest expense. Gains and losses associated with foreign currency derivatives are reported in our condensed consolidated statements of operations as either crude oil, refined products and LPG sales or other income (expense).

(2) Transfers into or out of level 3 represent existing assets or liabilities that were either previously categorized at a higher level for which the inputs to the model became unobservable or that were previously classified as level 3 for which the lowest significant input became observable during the period. There were no transfers into or out of level 3 during the period.

(3) The change in unrealized gains and losses related to our level 3 assets and liabilities still held at the end of the period are either recognized in earnings or deferred in AOCI through the application of hedge accounting. Unrealized gains and losses related to our level 3 derivatives that are still held at March 31, 2008 that are recognized in earnings are included in our condensed consolidated statements of operations as crude oil, refined products and LPG sales or purchases for our commodity derivatives, other income (expense) for our interest rate derivatives and crude oil, refined products and LPG sales for our foreign currency derivatives.

We believe an analysis of instruments classified as level 3 should be undertaken with the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and are therefore offset by the underlying hedged transactions. Accordingly, gains or losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business.

Note 11 Income Taxes

U.S. Federal and State Taxes

As a master limited partnership, we are not subject to U.S. federal income taxes; rather the tax effect of our operations is passed through to our unitholders. We are subject to state income taxes in some states but the expense is immaterial.

Canadian Federal and Provincial Taxes

Certain of our Canadian subsidiaries (acquired through the Pacific merger in 2006) are corporations for Canadian tax purposes, thus their operations are subject to Canadian federal and provincial income taxes. The remainder of our Canadian operations is conducted through an operating limited partnership, which is a flow-through entity for tax purposes. In June 2007, Canadian legislation was passed that imposes entity-level taxes on certain types of flow-through entities. The legislation refers to safe harbor guidelines that grandfather certain existing entities and delay the effective date of such legislation until 2011 provided that the entities do not exceed the normal growth guidelines. Although limited guidance is currently available, we believe that the legislation will apply to our Canadian partnerships. We believe that we are currently within the normal growth guidelines as defined in the legislation, which would delay the effective date for us until 2011. We continuously review acquisition opportunities, including Canadian opportunities which, if consumated, could cause us to exceed the normal growth guidelines. Included in our deferred income tax expense for the quarter ended March 31, 2008 is a credit related to a reduction in the rate applied to entities in Canada.

We adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48), an interpretation of SFAS No. 109 *Accounting for Income Taxes*, on January 1, 2007. The adoption of FIN 48 had no material impact on our financial statements. We recognize interest and penalties related to uncertain tax positions in income tax expense. At March 31, 2008, we have no material assets, liabilities or accrued interest associated with uncertain tax positions.

We file income tax returns in Canadian federal and various provincial jurisdictions. Generally, we are no longer subject to Canadian federal and provincial income tax examinations for years assessed before March 31, 2005.

Note 12 Commitments and Contingencies

Litigation

Pipeline Releases. In January 2005 and December 2004, we experienced two unrelated releases of crude oil that reached rivers located near the sites where the releases originated. 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. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the Environmental Protection Agency (the EPA), the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4 million to $5 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. The EPA has referred these two crude oil releases, as well as several other smaller releases, to the U.S. Department of Justice (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 the DOJ and the 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. We understand that the maximum permissible penalty, if any, that the EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. We believe that several mitigating circumstances and factors exist that are likely to substantially reduce any penalty that might be imposed by the EPA, and will continue to engage in discussions with the EPA and the DOJ with respect to such mitigating circumstances and factors, as well as the injunctive remedies proposed.

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.

The People of the State of California v. Pacific Pipeline System, LLC (PPS). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when Line 63 was severed as a result of a landslide caused by heavy rainfall in the Pyramid Lake area of Los Angeles County. Total projected emergency response, remediation and restoration costs are approximately $26 million, substantially all of which have been incurred and recovered under a pre-existing PPS pollution liability insurance policy.

In connection with this release, in March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four-count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleges the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. The fines that can be assessed against PPS for the violations of the strict liability statutes are based, in large measure, on the volume of unrecovered crude oil that was released into the environment, and, therefore, the maximum state fine, if any, that can be assessed is estimated to be approximately $1.4 million, in the aggregate. This amount is subject to a downward adjustment with respect to actual volumes of crude oil recovered and the State of California has the discretion to further reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the alleged offenses cannot be ascertained. We will defend against these charges. In addition to these fines, the State of California has indicated that it may seek to recover approximately $150,000 in natural resource damages against PPS in connection with this matter. The mitigating factors may also serve as a basis for a downward adjustment of any natural resource damages amount. We believe that the alleged violations are without merit and intend to defend against them, and that defenses and mitigating factors should apply. We are in settlement discussions with the State of California.

The EPA is also pursuing a claim in connection with this release and has referred this matter to the DOJ for the initiation of proceedings to assess civil penalties against PPS. We understand that the maximum permissible penalty, if any, that the EPA could assess under relevant statutes would be approximately $4.2 million. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty that might be imposed by the EPA, and intend to pursue discussions with the EPA regarding such defenses and mitigating circumstances and factors. Because of the uncertainty associated with these factors, the final amount of the penalty that will be claimed by the EPA cannot be ascertained. While we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter involves the allocation of responsibility for remediation of MTBE contamination at the Pacific Atlantic Terminals LLC (PAT) facility at Paulsboro, New Jersey. The estimated maximum potential remediation cost ranges up to $12 million. Both Exxon and GATX were prior owners of the terminal. 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. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. We intend to vigorously defend against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in mitigative costs or the imposition of fines and penalties.

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 and in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental

We have in the past experienced and in the future likely will experience releases of crude oil into the environment from our pipeline and storage operations. We also may discover environmental impacts from past releases that were previously unidentified. Although we maintain a program designed to help prevent releases, damages and liabilities incurred due to any such environmental releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (decrease) the rate of releases from such assets as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. The inclusion of additional miles of pipe in our operations may, however, 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 Energy LLC 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, including a Section 308 request received in late October 2007 with respect to a 400-barrel release of crude oil, a portion of which reached a tributary of the Colorado River in a remote area of West Texas.

At March 31, 2008, our reserve for environmental liabilities totaled approximately $35 million, of which approximately $14 million is classified as short-term and $21 million is classified as long-term. At March 31, 2008, we have recorded receivables totaling approximately $6 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 all known facts 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 in excess of this reserve may be higher and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Other. 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 properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

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. 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 13 Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Marketing. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative (G&A) expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our available cash (as defined in our partnership agreement) to our unitholders. We look at each period s earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which act to partially offset the wear and tear and age-related decline in the value of our principal fixed assets. These maintenance investments are a component of field operating costs included in segment profit or in maintenance capital, depending on the nature of the cost. Maintenance capital, which is deducted in determining available cash, consists of capital expenditures required either to maintain the existing operating capacity of partially or fully depreciated assets or to extend their useful lives. Capital expenditures made to expand our existing capacity, whether through construction or acquisition, are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures associated with existing assets that do not extend the useful life, improve the efficiency of the asset, or expand the operating capacity are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (in millions).

	Transportation	Facilities	Marketing	Total
Three Months Ended March 31, 2008				
Revenues:				
External Customers	$ 125	$ 33	$ 7,037	$ 7,195
Intersegment (1)	80	26		106
Total revenues of reportable segments	$ 205	$ 59	$ 7,037	$ 7,301
Equity earnings of unconsolidated entities	$ 1	$ 1	$	$ 2
Segment profit (2) (3) (4)	$ 89	$ 31	$ 57	$ 177
SFAS 133 impact (2)	$	$	$ (7)	$ (7)
Maintenance capital	$ 14	$ 5	$ 1	$ 20
Three Months Ended March 31, 2007				
Revenues:				
External Customers	$ 102	$ 26	$ 4,102	$ 4,230
Intersegment (1)	76	19	9	104
Total revenues of reportable segments	$ 178	$ 45	$ 4,111	$ 4,334
Equity earnings of unconsolidated entities	$ 1	$ 2	$	$ 3
Segment profit (2) (3) (4)	$ 73	$ 22	$ 66	$ 161
SFAS 133 impact (2)	$	$	$ (17)	$ (17)
Maintenance capital	$ 3	$ 4	$ 4	$ 11

(1) Intersegment sales are conducted at arms length.

(2) Amounts related to SFAS 133 are included in marketing revenues and impact segment profit. The SFAS 133 charge within the marketing segment for the three-month period ended March 31, 2008 does not include a $2 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net but does not impact segment profit.

(3) Marketing segment profit includes interest expense on contango inventory purchases of approximately $6 million and $11 million for the three months ended March 31, 2008 and 2007, respectively.

(4) The following table reconciles segment profit to consolidated income before cumulative effect of change in accounting principle (in millions):

	For the Three Months Ended March 31, 2008	2007
Segment profit	$ 177	$ 161
Depreciation and amortization	(48)	(40)
Interest expense	(42)	(41)
Interest income and other income (expense), net	3	5
Income tax benefit	2	
Net income	$ 92	$ 85

Note 14 Supplemental Condensed Consolidating Financial Information

Some, but not all of our 100% owned subsidiaries have issued full, unconditional, and joint and several guarantees of our Senior Notes. Given that certain, but not all, subsidiaries are guarantors of our Senior Notes, we are required to present the following supplemental condensed consolidating financial information. For purposes of the following footnote, Plains All American is referred to as Parent. Also, see Note 12 to our consolidated financial statements included in Part IV of our Annual Report on Form 10-K for the year ended December 31, 2007 for detail of which subsidiaries are classified as Guarantor Subsidiaries and which subsidiaries are classified as Non-Guarantor Subsidiaries.

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 Parent s 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 (all amounts in millions):

Condensed Consolidating Balance Sheet
As of March 31, 2008

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,118	$ 1,690	$ 99	$ (244)	$ 3,663
Property plant and equipment, net		3,868	626		4,494
Investment in unconsolidated entities	3,954	863		(4,590)	227
Other assets	23	1,260	318		1,601
Total assets	$ 6,095	$ 7,681	$ 1,043	$ (4,834)	$ 9,985
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 144	$ 3,711	$ 243	$ (233)	$ 3,865
Long-term debt	2,621	15			2,636
Other long-term liabilities		153	1		154
Total liabilities	2,765	3,879	244	(233)	6,655
Partners capital	3,330	3,802	799	(4,601)	3,330
Total liabilities and partners capital	$ 6,095	$ 7,681	$ 1,043	$ (4,834)	$ 9,985

As of December 31, 2007

	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,277	$ 3,858	$ 91	$ (2,553)	$ 3,673
Property plant and equipment, net		3,791	628		4,419
Investment in unconsolidated entities	3,881	863		(4,529)	215
Other assets	22	1,259	318		1,599
Total assets	$ 6,180	$ 9,771	$ 1,037	$ (7,082)	$ 9,906
LIABILITIES AND PARTNERS CAPITAL					
Total current liabilities	$ 134	$ 5,911	$ 237	$ (2,553)	$ 3,729
Long-term debt	2,622	2			2,624
Other long-term liabilities		128	1		129
Total liabilities	2,756	6,041	238	(2,553)	6,482
Partners capital	3,424	3,730	799	(4,529)	3,424
Total liabilities and partners capital	$ 6,180	$ 9,771	$ 1,037	$ (7,082)	$ 9,906

	Condensed Consolidating Statement of Operations Three Months Ended March 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 329	$ 30	$	$ 359
Field operating costs		(132)	(12)		(144)
General and administrative expenses		(37)	(3)		(40)
Depreciation and amortization	(1)	(43)	(4)		(48)
Operating income (loss)	(1)	117	11		127
Equity earnings in unconsolidated entities	133	11		(142)	2
Interest expense	(43)	1			(42)
Interest and other income (expense), net	2	1			3
Income tax benefit		2			2
Net income (loss)	$ 91	$ 132	$ 11	$ (142)	$ 92

	Three Months Ended March 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues (1)	$	$ 301	$ 29	$	$ 330
Field operating costs		(116)	(9)		(125)
General and administrative expenses		(48)	1		(47)
Depreciation and amortization	(1)	(34)	(5)		(40)
Operating income (loss)	(1)	103	16		118
Equity earnings in unconsolidated entities	126	16		(139)	3
Interest expense	(41)				(41)
Interest and other income (expense), net	1	4			5
Net income (loss)	$ 85	$ 123	$ 16	$ (139)	$ 85

(1) Net operating revenues are calculated as Total revenues less Crude oil, refined products and LPG purchases and related costs.

	Condensed Consolidating Statements of Cash Flows Three Months Ended March 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 91	$ 132	$ 11	$ (142)	$ 92
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	1	43	4		48
SFAS 133 mark-to-market adjustment		5			5
Gain on linefill		(3)			(3)
Equity compensation charge		6			6
Gain on foreign currency revaluation		(3)			(3)
Equity earnings in unconsolidated entities, net of distributions	(130)	(11)		142	1
Deferred income tax benefit		(3)			(3)
Changes in assets and liabilities, net of acquisitions	175	155	36		366
Net cash provided by operating activities	137	321	51		509
CASH FLOWS FROM INVESTING ACTIVITIES					
Additions to property and equipment		(98)	(51)		(149)
Investment in unconsolidated entities	(13)				(13)
Proceeds from sales of assets		10			10
Net cash used in investing activities	(13)	(88)	(51)		(152)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility		(181)			(181)
Net repayments on short-term letter of credit and hedged inventory facility		(62)			(62)
Distributions paid to common unitholders and general partner	(124)				(124)
Net cash used in financing activities	(124)	(243)			(367)
Effect of translation adjustment on cash		3			3
Net decrease in cash and cash equivalents		(7)			(7)
Cash and cash equivalents, beginning of period	1	23			24
Cash and cash equivalents, end of period	$ 1	$ 16	$	$	$ 17

	Three Months Ended March 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES:					
Net income	$ 85	$ 123	$ 16	$ (139)	$ 85
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	1	34	5		40
SFAS 133 mark-to-market adjustment		17			17
Inventory valuation adjustment		1			1
Gain on sale of investment assets		(4)			(4)
Equity compensation charge		19			19
Equity earnings in unconsolidated entities, net of distributions	(126)	(16)		139	(3)
Changes in assets and liabilities, net of acquisitions	155	82	(20)		217
Net cash provided by operating activities	115	256	1		372
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquistion		(17)			(17)
Additions to property and equipment		(133)	(1)		(134)
Investment in unconsolidated entities	(9)				(9)
Cash paid for linefill in assets owned		(4)			(4)
Proceeds from sales of assets		4			4
Net cash used in investing activities	(9)	(150)	(1)		(160)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on working capital revolving credit facility		(70)			(70)
Net repayments on short-term letter of credit and hedged inventory facility		(32)			(32)
Distributions paid to common unitholders	(88)				(88)
Distributions paid to general partner	(17)				(17)
Net cash used in financing activities	(105)	(102)			(207)
Effect of translation adjustment on cash		1			1
Net increase in cash and cash equivalents	1	5			6
Cash and cash equivalents, beginning of period	2	9			11
Cash and cash equivalents, end of period	$ 3	$ 14	$	$	$ 17

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 2007 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.

Highlights First Quarter of 2008 and 2007 (in millions, except per unit data)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007	Favorable/(Unfavorable) Variance $	Favorable/(Unfavorable) Variance %
Net income	$ 92	$ 85	$ 7	8%
Earnings per basic limited partner unit	$ 0.58	$ 0.62	$ (0.04)	(6)%
Earnings per diluted limited partner unit	$ 0.57	$ 0.61	$ (0.04)	(7)%
Basic weighted average units outstanding	116	109	7	6%
Diluted weighted average units outstanding	117	111	6	5%

Key items impacting the first three months of 2008 include:

Income Statement

Segment profit and net income increased approximately 10% and 8%, respectively, compared to the first quarter of 2007 while diluted earnings per unit decreased approximately 7%. The increases were driven by increased segment profit in the transportation and facilities segments, partially offset by decreased segment profit in the marketing segment. Included in these results were:

- Increased earnings resulting from acquisition and expansion activities;
- Decreased earnings resulting from less favorable market conditions compared to the first quarter of 2007;
- A loss of approximately $5 million related to the mark-to-market impact for open derivative instruments (compared to a loss of approximately $17 million for the first quarter of 2007); and

•Equity compensation plan expense of $6 million compared to approximately $19 million for the three months ended March 31, 2007. The decreased expense is primarily the result of the decrease in unit price for the first quarter of 2008 compared to the increase in unit price for the first quarter of 2007. The impact of the change in unit price was offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence in the first three months of 2007.

Balance Sheet and Capital Structure

•Capital expenditures for internal growth projects of $124 million for the first quarter of 2008, which represent approximately 33% of the 2008 planned expansion capital expenditures.

Acquisitions and Internal Growth Projects

The following table summarizes our capital expenditures incurred in the periods indicated (in millions):

	Three Months Ended March 31,			
	2008		2007	
Acquisition capital	$		$	24
Investment in unconsolidated entities		13		9
Internal growth projects		124		131
Maintenance capital		20		11
	$	157	$	175

Pending Acquisition

During April 2008, we signed a definitive agreement to acquire all of the shares of Rainbow Pipe Line Company, Ltd. (Rainbow) for approximately Canadian $540 million in cash. In conjunction with signing the agreement, we paid a deposit of approximately $54 million. Rainbow s assets include approximately 480 miles of mainline crude oil pipelines, approximately 140 miles of gathering pipelines and approximately 570,000 barrels of tankage along the system. Upon closing, we will also acquire approximately 1 million barrels of crude oil linefill at a value based on crude oil prices at such time. The system currently has a throughput capacity of approximately 200,000 barrels per day and 2007 volumes on the system averaged approximately 195,000 barrels per day. The acquisition is expected to close in the second quarter of 2008 and the acquired operations will be reflected primarily in our transportation segment. The transaction is subject to receipt of regulatory approvals and satisfaction of customary closing conditions.

In anticipation of closing the Rainbow acquisition, we recently entered into forward currency exchange contracts, which exchange Canadian dollars and US dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. Additionally, we entered into a financial option strategy, whereby we established a minimum and maximum per barrel price to hedge the commodity price risk associated with the anticipated purchase of crude oil linefill.

Internal Growth Projects

We forecast approximately $380 million in capital expenditures for expansion projects during calendar year 2008, of which approximately $124 million was incurred in the first three months. These projects include the construction and expansion of pipeline systems and crude oil and LPG storage facilities. Following are some of the more notable projects undertaken in 2008 and the estimated expenditures for the year (in millions):

Projects		**2008**
Patoka tankage	$	43
Kerrobert facility		36
Paulsboro tankage		30
Fort Laramie tank expansion		22
West Hynes tankage		13
Edmonton tankage and connections		12
Bumstead expansion		10
Pier 400 (1)		10
Other projects (2)		204
Total	$	380

(1) This project requires approval from a number of city and state regulatory agencies in California. Accordingly, the timing and amount of additional costs, if any, related to Pier 400 are not certain at this time.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carryover of projects started in 2007, including the Salt Lake City pipeline for which estimated costs have increased approximately $50 million over previous estimates primarily due to weather related factors and adverse soil conditions.

We forecast approximately $60 million in capital expenditures for maintenance projects during calendar year 2008, of which approximately $20 million was incurred in the first three months.

Results of Operations

	Three Months Ended March 31,			
	2008		**2007**	
	(in millions)			
Transportation segment profit	$	89	$	73
Facilities segment profit		31		22
Marketing segment profit		57		66
Total segment profit		177		161
Depreciation and amortization		(48)		(40)
Interest expense		(42)		(41)
Interest income and other income (expense), net		3		5
Income tax benefit		2		
Net income	$	92	$	85

Analysis of Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. 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 investment. See Note 13 to our Condensed Consolidated Financial Statements for further discussion on how we evaluate segment performance.

Transportation

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

	Three Months Ended March 31,		Favorable (Unfavorable) Variance	
	2008	2007	$	%
Operating Results [1] (in millions, except per barrel amounts)				
Revenues				
Tariff activities	$ 174	$ 153	$ 21	14%
Trucking	31	25	6	24%
Total transportation revenues	205	178	27	15%
Costs and Expenses				
Trucking costs	(21)	(18)	(3)	(17)%
Field operating costs (excluding equity compensation charge)	(79)	(66)	(13)	(20)%
Equity compensation charge - operations [2]		(2)	2	100%
Segment G&A expenses (excluding equity compensation charge) [3]	(14)	(13)	(1)	(8)%
Equity compensation charge - general and administrative [2]	(3)	(7)	4	57%
Equity earnings in unconsolidated entities	1	1		
Segment profit	$ 89	$ 73	$ 16	22%
Maintenance capital	14	3	11	367%
Segment profit per barrel	$ 0.36	$ 0.31	$ 0.05	16%

	Three Months Ended March 31,		Favorable (Unfavorable) Variance	
	2008	2007	Volumes	%
Average Daily Volumes (in thousands of barrels) [4]				
Tariff activities				
All American	46	50	(4)	(8)%
Basin	363	342	21	6%
Capline	190	235	(45)	(19)%
Line 63/Line 2000	162	181	(19)	(10)%
Salt Lake City Area System	97	96	1	1%
West Texas/New Mexico Area Systems	377	368	9	2%
Manito	69	74	(5)	(7)%
Rangeland	62	64	(2)	(3)%
Refined products	115	115		
Other	1,180	1,085	95	9%
Tariff activities total	2,661	2,610	51	2%
Trucking	97	109	(12)	(11)%
Transportation activities total	**2,758**	**2,719**	**39**	**1%**

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

(2) Compensation expense related to our equity compensation plans.

(3) Segment G&A expenses reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on management s assessment of the business activities for that period. The proportional allocations by segment require judgment by management and may be adjusted in the future based on the business activities that exist during each period.

(4) 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:

Operating Revenues and Volumes. As noted in the table above, our transportation segment revenues and volumes increased for the first quarter of 2008 compared to the first quarter of 2007. The table below presents the significant variances in revenues (in millions) and average daily volumes (thousands of barrels per day) between the comparative periods:

	Revenues	Volumes
2008 compared to 2007		
Increase due to:		
Loss allowance [1]	$ 10	
Expansion project [2]	2	31
Capline system [3]	(3)	(45)
Turnaround [4]	1	55
Trucking [5]	6	(12)
Other [6]	11	10
Total variance	$ 27	39

(1) As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the average market value at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. Loss allowance revenues increased for the first quarter of 2008 compared to the first quarter of 2007 by approximately $10 million primarily due to increased commodity prices. Volumes related to loss allowance are excluded from our calculation of average daily volumes.

(2) The Cheyenne expansion project, completed during the latter half of 2007, contributed approximately $2 million in additional revenues and approximately 31 thousand barrels per day in additional volumes for the first quarter of 2008 compared to the first quarter of 2007.

(3) Due to refinery downtime, our Capline system experienced a temporary decline in volumes and revenues for the first quarter of 2008 compared to the first quarter of 2007. Although similar declines could occur in future periods, we expect the volumes and revenues to increase for the second quarter of 2008.

(4) In the first quarter of 2007, turnaround maintenance was required on the refinery that is served by our Cushing-to-Broome pipeline system. In the first quarter of 2008, there was no such requirement and thus, our volumes on that system were higher for the first quarter of 2008 than in the comparable period of 2007.

(5) Trucking revenues increased due to an acquisition during the first quarter of 2007 and an increase in rates during the second quarter of 2007. Volumes decreased due to a reduced number of shorter hauls in favor of more profitable longer hauls.

(6) Miscellaneous revenue and volume variances on various systems.

Field Operating Costs. The 2008 increased costs primarily relate to (i) utilities costs, which increased due to higher market prices, (ii) payroll and employee benefits partially relating to retention compensation attributable to the relocation and integration of the SCADA system control room for pipelines acquired in the Pacific acquisition, (iii) additional pipeline inspection and integrity maintenance costs, and (iv) increased maintenance costs.

General and Administrative Expenses. Our G&A expenses were impacted in 2008 by equity compensation charges that decreased in 2008 compared to 2007 primarily as a result of the decrease in unit price for the first quarter of 2008 compared to the increase in unit price for the first quarter of 2007. The impact of the change in unit price was offset by additional LTIP grants that are considered probable of vesting and additional expense for Class B units. The Class B plan was not in existence in the first quarter of 2007.

Maintenance Capital. The increase in maintenance capital for the first quarter of 2008 compared to the first quarter of 2007 is primarily due to the timing of current projects and projects that were carried over from 2007. In addition, maintenance capital in the first quarter of 2007 was lower than forecast.