UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of The
Securities Exchange Act of 1934

Date of Report (Date of earliest event reported)—February 11, 2009

Plains All American Pipeline, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**1-14569**	**76-0582150**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

333 Clay Street, Suite 1600, Houston, Texas 77002
(Address of principal executive offices) (Zip Code)

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

(Former name or former address, if changed since last report.)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

o Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

o Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

o Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

o Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 9.01. Financial Statements and Exhibits

(d) Exhibit 99.1 – Press Release dated February 11, 2009.

Item 2.02 and Item 7.01. Results of Operations and Financial Condition; Regulation FD Disclosure

Plains All American Pipeline, L.P. (the "Partnership") today issued a press release reporting its fourth-quarter and annual 2008 results. We are furnishing the press release, attached as Exhibit 99.1, pursuant to Item 2.02 and Item 7.01 of Form 8-K. Pursuant to Item 7.01 we are providing detailed guidance for financial performance for the first quarter of calendar 2009 and for the full year. In accordance with General Instruction B.2. of Form 8-K, the information presented herein under this Item 7.01 shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), nor shall it be deemed incorporated by reference in any filing under the Exchange Act or Securities Act of 1933, as amended, except as expressly set forth by specific reference in such a filing.

Disclosure of First Quarter and Full Year 2009 Guidance

EBIT and EBITDA (each as defined below in Note 1 to the "Operating and Financial Guidance" table) are non-GAAP financial measures. Net income and cash flows from operating activities are the most directly comparable GAAP measures to EBIT and EBITDA. In Note 10 below, we reconcile EBITDA and EBIT to net income for the 2009 guidance periods presented. It is, however, impractical to reconcile EBIT and EBITDA to cash flows from operating activities for a forecasted period. We encourage you to visit our website at *www.paalp.com* (in particular the section entitled "Non-GAAP Reconciliation"), which presents a historical reconciliation of certain commonly used non-GAAP financial measures, including EBIT and EBITDA. We present EBIT and EBITDA because we believe they provide additional information with respect to both the performance of our fundamental business activities and our ability to meet our future debt service, capital expenditures and working capital requirements. We also believe that debt holders commonly use EBITDA to analyze partnership performance. In addition, we have highlighted the impact of our equity compensation plans on Segment Profit, EBITDA, Net Income and Net Income per Basic and Diluted Limited Partner Unit.

The following guidance for the three-month period ending March 31, 2009 and twelve-month period ending December 31, 2009 is based on assumptions and estimates that we believe are reasonable given our assessment of historical trends (modified for changes in market conditions), business cycles and other reasonably available information. Projections covering multi-quarter periods contemplate inter-period changes in future performance resulting from new expansion projects, seasonal operational changes (such as LPG sales) and acquisition synergies. Our assumptions and future performance, however, are both subject to a wide range of business risks and uncertainties, so no assurance can be provided that actual performance will fall within the guidance ranges. Please refer to information under the caption "Forward-Looking Statements and Associated Risks" below. These risks and uncertainties, as well as other unforeseeable risks and uncertainties, could cause our actual results to differ materially from those in the following table. The operating and financial guidance provided below is given as of the date hereof, based on information known to us as of February 10, 2009. We undertake no obligation to publicly update or revise any forward-looking statements.

Plains All American Pipeline, L.P.
Operating and Financial Guidance
(in millions, except per unit data)

	2009 Guidance [1]			
	3 Months Ending March 31,		12 Months Ending December 31,	
	Low	High	Low	High
Segment Profit				
Net revenues (including equity earnings from unconsolidated entities)	$ 444	$ 458	$ 1,753	$ 1,788
Field operating costs	(170)	(166)	(664)	(654)
General and administrative expenses	(48)	(46)	(189)	(184)
	226	246	900	950
Depreciation and amortization expense	(57)	(55)	(232)	(226)
Interest expense, net	(54)	(52)	(214)	(207)
Income tax expense	(3)	(2)	(11)	(8)
Other income (expense), net	2	2	6	6
Net Income	**$ 114**	**$ 139**	**$ 449**	**$ 515**
Net Income to Limited Partners	$ 81	$ 106	$ 312	$ 375
Basic Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	123	123	123	123
Net Income Per Unit	$ 0.66	$ 0.86	$ 2.54	$ 3.05
Diluted Net Income Per Limited Partner Unit				
Weighted Average Units Outstanding	124	124	124	124
Net Income Per Unit	$ 0.65	$ 0.85	$ 2.52	$ 3.02
EBIT	**$ 171**	**$ 193**	**$ 674**	**$ 730**
EBITDA	**$ 228**	**$ 248**	**$ 906**	**$ 956**
Selected Items Impacting Comparability				
Equity compensation charge	$ (7)	$ (7)	(29)	(29)
Excluding Selected Items Impacting Comparability				
Adjusted Segment Profit				
Transportation	$ 107	$ 112	$ 476	$ 488
Facilities	43	46	195	203
Marketing	83	95	258	288
Other Income (Expense), net	2	2	6	6
Adjusted EBITDA	$ 235	$ 255	$ 935	$ 985
Adjusted Net Income	$ 121	$ 146	$ 478	$ 544
Adjusted Basic Net Income per Limited Partner Unit	$ 0.72	$ 0.92	$ 2.76	$ 3.28
Adjusted Diluted Net Income per Limited Partner Unit	$ 0.71	$ 0.91	$ 2.73	$ 3.25

(1) The projected average foreign exchange rate is $1.18 CAD to $1 USD. The rate as of February 10, 2009 was $1.25 CAD to $1 USD. A $0.10 change in the fx rate will impact annual EBITDA by approximately $12 million.

Notes and Significant Assumptions:

1. *Definitions.*

EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes and depreciation and amortization expense
Segment Profit	Net revenues (including equity earnings, as applicable) less field operating costs and segment general and administrative expenses

Bbls/d	Barrels per day
Bcf	Billion cubic feet
LTIP	Long-Term Incentive Plan
LPG	Liquefied petroleum gas and other natural gas-related petroleum products (primarily propane and butane)
FX	Foreign currency exchange
General partner (GP)	As the context requires, "general partner" refers to any or all of (i) PAA GP LLC, the owner of our 2% general partner interest, (ii) Plains AAP, L.P., the sole member of PAA GP LLC and owner of our incentive distribution rights and (iii) Plains All American GP LLC, the general partner of Plains AAP, L.P.
Class B units	Class B units of Plains AAP, L.P.

2. *Business Segments*. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. The following is a brief explanation of the operating activities for each segment as well as key metrics.

a. *Transportation.* Our transportation segment operations generally consist of fee-based activities associated with transporting crude oil and refined products on pipelines, gathering systems, trucks and barges. We generate revenue through a combination of tariffs, third-party leases of pipeline capacity and transportation fees. We also include in this segment our equity earnings from our non-controlling interest in the Butte and Frontier pipeline systems and Settoon Towing.

Pipeline volume estimates are based on historical trends, anticipated future operating performance and completion of internal growth projects. Volumes are influenced by maintenance schedules at refineries, production declines, weather and other natural disasters including hurricanes, changes in the quantity of inventory held in tanks, and other external factors beyond our control. Segment profit is forecast using the volume assumptions in the table below, priced at forecasted tariff rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation. Actual segment profit could vary materially depending on the level and mix of volumes transported or expenses incurred during the period.

The following table summarizes our total pipeline volumes and highlights major systems that are significant either in total volumes transported or in contribution to total transportation segment profit.

	2009 Guidance	
	Three Months Ending March 31,	Twelve Months Ending December 31,
Average Daily Volumes (000 Bbls/d)		
All American	43	43
Basin	360	360
Capline	210	220
Line 63 / 2000	140	140
Salt Lake City Area Systems (1) (2)	140	145
West Texas / New Mexico Area Systems (1)	365	360
Rainbow	200	200
Manito	70	70
Rangeland	60	55
Refined Products	115	115
Other	1,157	1,217
	2,860	2,925
Trucking	100	110
	2,960	3,035
Average Segment Profit ($/Bbl)		
Excluding Selected Items Impacting Comparability	$ 0.41(3)	$ 0.44(3)

(1) The aggregate of multiple systems in the respective areas.
(2) With the completion of the new expansion project, reported volumes will increase approximately 40,000 Bbl/d. However, not all of the increase is incremental volume.
(3) Mid-point of guidance.

b. *Facilities*. Our facilities segment operations generally consist of fee-based activities associated with providing storage, terminalling and throughput services for crude oil, refined products and LPG, as well as LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. This segment also includes our equity earnings from our 50% investment in PAA/Vulcan Gas Storage, LLC, which owns and operates approximately 31 Bcf of underground natural gas storage capacity and is constructing an additional projected 19 Bcf of underground storage capacity.

Segment profit is forecast using the volume assumptions in the table below, priced at forecasted rates, less estimated field operating costs and G&A expenses. Field operating costs do not include depreciation.

	2009 Guidance	
	Three Months Ending March 31,	Twelve Months Ending December 31,
Operating Data		
Crude oil, refined products and LPG storage (MMBbls/Mo.)	56	57
Natural Gas Storage (Bcf/Mo.)	16	19
LPG Processing (MBbl/d)		

	18	18
Facilities Activities Total [1]		
Avg. Capacity (MMBbls/Mo.)	59	61
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability	$ 0.25[2]	$ 0.27[2]

(1) 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 barrel of crude oil 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.

(2) Mid-point of guidance.

c. *Marketing*. Our marketing segment operations generally consist of the following merchant activities:

- the purchase of U.S. and Canadian crude oil at the wellhead and the bulk purchase of crude oil at pipeline and terminal facilities, as well as the purchase of foreign cargoes at their load port and various other locations in transit;
- the storage of inventory during contango market conditions and the seasonal storage of LPG;
- the purchase of refined products and LPG from producers, refiners and other marketers;
- the resale or exchange of crude oil, refined products and LPG at various points along the distribution chain to refiners or other resellers to maximize profits; and
- the transportation of crude oil, refined products and LPG on trucks, barges, railcars, pipelines and ocean-going vessels to our terminals and third-party terminals.

The level of profit in the marketing segment is influenced by overall market structure and the degree of volatility in the crude oil market as well as variable operating expenses. Forecasted operating results for the three-month period ending March 31, 2009 reflect the current market structure and seasonal, weather-related variations in LPG sales. Variations in market structure or volatility could cause actual results to differ materially from forecasted results.

We forecast segment profit using the volume assumptions stated below, as well as estimates of unit margins, field operating costs, G&A expenses and carrying costs for contango inventory, based on current and anticipated market conditions. Field operating costs do not include depreciation. Realized unit margins for any given lease-gathered barrel could vary significantly based on a variety of factors including location, quality and contract structure. Accordingly, the projected segment profit per barrel can vary significantly even if aggregate volumes are in line with the forecasted levels.

	2009 Guidance	
	Three Months Ending March 31,	Twelve Months Ending December 31,
Average Daily Volumes (MBbl/d)		
Crude Oil Lease Gathering	640	640
LPG Sales	165	105
Refined Products	30	30
Waterborne foreign crude imported	75	75
	910	850
Segment Profit per Barrel ($/Bbl)		
Excluding Selected Items Impacting Comparability	$ 1.09[1]	$ 0.88[1]

(1) Mid-point of guidance.

3. *Depreciation and Amortization.* We forecast depreciation and amortization based on our existing depreciable assets, forecasted capital expenditures and projected in-service dates. Depreciation is computed using the straight-line method over estimated useful lives, which range from 3 years (for office furniture and equipment) to 40 years (for certain pipelines, crude oil terminals and facilities). Depreciation may vary during any one period due to gains and losses on intermittent sales of assets, asset retirement obligations, or asset impairments.

4. *Selected Items Impacting Comparability*. Our actual results will reflect certain mark-to-market items such as gains and losses related to derivative activities, gains and losses from unrealized foreign currency transactions, and inventory revaluation adjustments. Our adjusted results exclude these selected items impacting comparability until such time that the underlying and offsetting physical transaction settles. Although the economics of these transactions as a whole are embedded in our guidance presented here, our selected items impacting comparability do not reflect these items as there is no accurate way to forecast the magnitude and timing. The timing of when these items will impact our results is primarily dependent on the timing of the purchase or sale of the underlying inventory which is dependent on market variables and other factors. The magnitude of these items is dependent on market prices and exchange rates at a point in time. As such, our actual results could differ materially from our projections.

5. *Capital Expenditures and Acquisitions*. Although acquisitions constitute a key element of our growth strategy, the forecasted results and associated

estimates do not include any forecasts for acquisitions that may be made after the date hereof. Capital expenditures during calendar 2009 are forecasted to be approximately $295 million for expansion projects with an additional $70 to $80 million for maintenance projects. Following are some of the more notable projects and forecasted expenditures for the year:

		Calendar 2009 (in millions)	
Expansion Capital			
· St. James Phase III [1]		$85	
· Kerrobert pumping project		34	
· Cushing - Phase VII		29	
· Rangeland tankage and connections		29	
· Nipisi storage and truck terminal		20	
· Patoka Phase II		20	
· Paulsboro tankage		13	
· Other projects, including acquisition related expansion projects [2]		65	
		295	
Maintenance Capital	$70		$80
Total Projected Capital Expenditures (excluding acquisitions)	$365		$375

(1) Includes a dock and condensate tanks.

(2) Primarily pipeline connections, upgrades and truck stations, new tank construction and refurbishing, and carry-over of projects started in 2008.

6. *Capital Structure.* This guidance is based on our capital structure as of December 31, 2008.

7. *Interest Expense*. Debt balances are projected based on estimated cash flows, estimated distribution rates, forecasted capital expenditures for maintenance and expansion projects, expected timing of collections and payments, and forecasted levels of inventory and other working capital sources and uses. Interest rate assumptions for variable rate debt are based on the current forward LIBOR curve.

Included in interest expense are commitment fees, amortization of long-term debt discounts or premiums, deferred amounts associated with terminated interest-rate hedges and interest on short-term debt for non-contango inventory (primarily hedged LPG inventory and New York Mercantile Exchange and IntercontinentalExchange margin deposits). Interest expense is net of amounts capitalized for major expansion capital projects and does not include interest on borrowings for inventory stored in a contango market. We treat interest on contango-related borrowings as carrying costs of crude oil and include it in purchases and related costs.

8. *Net Income per Unit.* Basic net income per limited partner unit is calculated by dividing net income allocated to limited partners by the basic weighted average units outstanding during the period.

	Guidance (in millions, except per unit data)			
	Three Months Ending March 31, 2009		Twelve Months Ending December 31, 2009	
	Low	High	Low	High
Numerator for basic and diluted earnings per limited partner unit:				
Net Income	$ 114	$ 139	$ 449	$ 515
General partner's incentive distribution	(36)	(36)	(151)	(151)
General partner's incentive distribution reduction	5	5	19	19
	83	108	317	383
General partner 2% ownership	(2)	(2)	(5)	(8)
Net income available to limited partners	$ 81	$ 106	$ 312	$ 375
Denominator:				
Denominator for basic earnings per limited partner unit-weighted average number of limited partner units	123	123	123	123
Effect of dilutive securities: Weighted average LTIP units	1	1	1	1
Denominator for diluted earnings per limited partner unit-weighted average number of limited partner units	124	124	124	124
Basic net income per limited partner unit	$ 0.66	$ 0.86	$ 2.54	$ 3.05
Diluted net income per limited partner unit	$ 0.65	$ 0.85	$ 2.52	$ 3.02

In conjunction with the Pacific and Rainbow acquisitions, the general partner reduced the amounts due it as incentive distributions by an aggregate amount of $75 million. Approximately $38 million of this reduction was realized as of December 31, 2008. Incentive distributions will be reduced by $21 million in 2009, $11 million in 2010 and $5 million in 2011.

The relative amount of the incentive distribution varies directionally with the number of units outstanding and the level of the distribution on the units. Based on the current number of units outstanding, each $0.05 per unit annual increase or decrease in the distribution relative to forecasted amounts decreases or increases, respectively, net income available for limited partners by approximately $6 million ($0.05 per unit) on an annualized basis.

9. *Equity Compensation Plans*. The majority of grants outstanding under our equity compensation plans (LTIP and Class B units) contain vesting criteria that are based on a combination of performance benchmarks and service period. The grants will vest in various percentages, typically on the later to occur of specified earliest vesting dates and the dates on which minimum distribution levels are reached. Among the various grants outstanding as of February 10, 2009, estimated vesting dates range from May 2009 to January 2016 and minimum annualized distribution levels range from $2.80 to $4.50. For some awards, a percentage of any remaining units will vest on a date certain in 2011 or 2012 and all others are forfeited.

On January 14, 2009, we declared an annualized distribution of $3.57 payable on February 13, 2009 to our unitholders of record as of February 3, 2009. We have made the assessment that a $3.75 distribution level is probable of occuring and accordingly, for grants that vest at annualized distribution levels of $3.75 or less, guidance includes an accrual over the applicable service period at an assumed market price of $40.00 per unit as well as the fair value associated with awards that will vest on a date certain The actual amount of equity compensation expense amortization in any given period will be directly influenced by (i) our unit price at the end of each reporting period, (ii) our unit price on the date of actual vesting, (iii) the amount of the amortization in the early years, (iv) the probability assessment of achieving future distribution rates, and (v) new equity compensation award grants. For example, a $3.00 change in the unit price assumption at March 31, 2009 would change the first-quarter equity compensation expense by approximately $2 million. Therefore, actual net income

could differ materially from our projections.

10. *Reconciliation of EBITDA and EBIT to Net Income.* The following table reconciles the three-month and twelve month guidance ranges ending March 31, 2009 and December 31, 2009, respectively, for EBITDA and EBIT to net income.

	Three Months Ending March 31, 2009		Twelve Months Ending December 31, 2009	
	Low	High	Low	High
	(in millions)		(in millions)	
Reconciliation to Net Income				
EBITDA	$ 228	$ 248	$ 906	$ 956
Depreciation and amortization	57	55	232	226
EBIT	171	193	674	730
Interest expense	54	52	214	207
Income tax expense	3	2	11	8
Net Income	$ 114	$ 139	$ 449	$ 515

Forward-Looking Statements and Associated Risks

All statements included in this report, other than statements of historical fact, are forward-looking statements, including, but not limited to, statements identified by the words “anticipate,” “believe,” “estimate,” “expect,” “plan,” “intend” and “forecast,” as well as similar expressions and statements regarding our business strategy, plans and objectives of our management 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 are reasonable assumptions. Certain factors could cause actual results to differ materially from 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 success 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;
- our ability to obtain debt or equity financing on satisfactory terms to fund expansion projects,

working capital requirements and the repayment or refinancing of indebtedness;

- the future performance of acquired assets and businesses and the risks associated with operating in lines of business that are distinct and separate from our historical operations;
- unanticipated changes in crude oil market structure and volatility (or lack thereof);
- the impact of current and future laws, rulings, governmental regulations and 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 deteriorated 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.

We undertake no obligation to publicly update or revise any forward-looking statements. Further information on risks and uncertainties is available in our filings with the Securities and Exchange Commission, which information is incorporated by reference herein.

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 hereunto 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: February 11, 2009

By: /s/ AL SWANSON

Name: Al Swanson

Title: *Senior Vice President and Chief Financial Officer*

PLAINS ALL AMERICAN PIPELINE, L.P.

News Release

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FOR IMMEDIATE RELEASE

Plains All American Pipeline, L.P. Reports Solid Fourth-Quarter and Full-Year 2008 Results

(Houston – February 11, 2009) Plains All American Pipeline, L.P. (NYSE: PAA) today reported net income of $98 million, or $0.56 per diluted limited partner unit, for the fourth quarter 2008 and net income of $437 million, or $2.67 per diluted limited partner unit for the full year 2008. Net income for the fourth quarter 2007 was $77 million, or $0.47 per diluted limited partner unit, and net income for the full year 2007 was $365 million, or $2.52 per diluted limited partner unit.

The Partnership reported earnings before interest, taxes, depreciation and amortization ("EBITDA") of $213 million and $852 million for the respective fourth-quarter and full-year 2008 periods, compared with reported EBITDA for the comparable 2007 periods of $164 million and $723 million. (See the section of this release entitled "Non-GAAP Financial Measures" and the attached tables for discussion of EBITDA and other non-GAAP financial measures, and reconciliations of such measures to the comparable GAAP measures.)

"2008 represents another year of solid execution for the Partnership," stated Greg L. Armstrong, Chairman and CEO of Plains All American. "In addition to delivering solid operating and financial results in a volatile and challenging environment, we consummated two strategic and accretive acquisitions for $731 million, invested approximately $491 million in organic growth capital and increased our limited partner distributions in 2008 by more than 6%."

Armstrong continued, "Despite challenging domestic and global energy and capital market conditions, PAA's business model has performed as designed, we continue to have solid demand for our assets and services, and we have a strong capital structure, significant liquidity and healthy distribution coverage. As a result of these factors, we believe that we are well positioned to continue to execute our business plan, continue our track record of performing in-line with operational and financial guidance and create long-term value for our stakeholders."

Reported results for the periods ended December 31, 2008 were impacted by certain selected items that impact comparability between reporting periods. These items are excluded from adjusted results, as further described in the table below. The fourth quarter's reported results were also impacted by a number of other items including the carryover impact from recent hurricanes, resolution of pipeline tariff protests, a linefill related gain and various other items that largely offset each other and were not excluded from adjusted results.

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The Partnership's fourth-quarter 2008 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $121 million, $0.74 and $236 million, respectively. The Partnership's fourth-quarter 2007 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA were $80 million, $0.50 and $167 million, respectively. On a comparable basis, fourth-quarter 2008 adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA increased 51%, 48% and 41%, respectively, over the corresponding metrics for the fourth quarter 2007.

The Partnership's adjusted net income, adjusted net income per diluted limited partner unit and adjusted EBITDA for the full year 2008 were $472 million, $2.96 and $887 million, respectively. These metrics for 2007 were $431 million, $3.09 and $779 million, respectively. On a comparative basis, 2008 adjusted net income and adjusted EBITDA increased 10% and 14%, respectively, over 2007, while adjusted net income per diluted limited partner unit decreased approximately 4% between periods.

The following table summarizes selected items that the Partnership believes impact comparability of financial results between reporting periods:

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007
	(In millions, except per unit data)			
Selected items impacting comparability				
Equity compensation benefit/(charge) [1]	$ 2	$ (6)	$ (21)	$ (44)
Inventory valuation adjustments net of related gains/(losses) from derivative activities [2] [3]	(16)	—	(11)	—
Gains/(losses) from derivative activities [2] [4]	4	(9)	7	(24)
Net loss on foreign currency revaluation	(13)	—	(21)	—
Gains on Rainbow acquisition-related foreign currency and linefill hedges	—	—	11	—
Gain on sale of linefill	—	12	—	12
Deferred income tax expense	—	—	—	(10)

Selected items impacting comparability	(23)	(3)	(35)	(66)
Less: GP 2% portion of selected items impacting comparability	—	—	1	1
LP 98% portion of selected items impacting comparability	$ (23)	$ (3)	$ (34)	$ (65)
Impact to basic net income per limited partner unit	$ (0.19)	$ (0.02)	$ (0.29)	$ (0.57)
Impact to diluted net income per limited partner unit	$ (0.18)	$ (0.03)	$ (0.29)	$ (0.57)

(1) The equity compensation benefit for the three months and charge for the twelve months ended December 31, 2008 and 2007 excludes the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans for the three months and twelve months ended December 31, 2008 is less than $1 million and approximately $3 million, respectively. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans for the three months and twelve months ended December 31, 2007 is $1 million and $5 million, respectively.

(2) Beginning with the first quarter of 2008, gains and losses from derivative activities related to revalued inventory are included in the line item "Inventory valuation adjustments net of gains and losses from related derivative activities"; gains and losses from derivative activities not related to revalued inventory are included in the line item "Gains and losses from derivative activities".

(3) Includes a net inventory valuation adjustment of $81 million and $146 million for the three months and twelve months ended December 31, 2008, respectively. Also includes gains from related derivative activities of $65 million and $134 million for the three months and twelve months ended December 31, 2008, respectively.

(4) The gain from derivative activities for both the three months and twelve months ended December 31, 2008 includes a $3 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The loss from derivative activities for the three months and twelve months ended December 31, 2007 includes a $2 million gain and $3 million gain, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

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The following tables present certain selected financial information by segment for the fourth-quarter and full-year reporting periods (amounts in millions):

	Three Months Ended December 31, 2008			Three Months Ended December 31, 2007		
	Transportation Operations	Facilities Operations	Marketing Operations	Transportation Operations	Facilities Operations	Marketing Operations
Revenues (1)	$ 246	$ 77	$ 4,755	$ 200	$ 57	$ 6,293
Purchases and related costs (1)	(21)	—	(4,663)	(22)	—	(6,197)
Field operating costs (excluding equity compensation charge) (1)	(85)	(28)	(47)	(75)	(21)	(39)
Equity compensation charge - operations	—	—	—	(1)	—	—
Segment G&A expenses (excluding equity compensation benefit/(charge)) (2)	(13)	(5)	(15)	(12)	(5)	(13)
Equity compensation benefit/(charge) - general and administrative	1	—	1	(3)	(1)	(2)
Equity earnings in unconsolidated entities	2	2	—	2	1	—
Reported segment profit	$ 130	$ 46	$ 31	$ 89	$ 31	$ 42
Selected items impacting comparability of segment profit (3):						
Equity compensation (benefit)/charge (4)	(1)	—	(1)	3	1	2
Inventory valuation adjustments net of related (gains)/losses from derivative activities (5) (6)	—	—	16	—	—	—
(Gains)/losses from derivative activities (5) (7)	—	—	(1)	—	—	11
Net loss on foreign currency revaluation	—	—	13	—	—	—
Gain on sale of linefill	—	—	—	—	—	(12)
Segment profit excluding selected items impacting comparability	$ 129	$ 46	$ 58	$ 92	$ 32	$ 43
Maintenance capital	$ 16	$ 8	$ 1	$ 13	$ 4	$ 2

	Twelve Months Ended December 31, 2008			Twelve Months Ended December 31, 2007		
	Transportation Operations	Facilities Operations	Marketing Operations	Transportation Operations	Facilities Operations	Marketing Operations
Revenues (1)	$ 927	$ 270	$ 29,350	$ 771	$ 210	$ 19,858
Purchases and related costs (1)	(88)	—	(28,873)	(80)	—	(19,366)
Field operating costs (excluding equity compensation charge) (1)	(331)	(104)	(185)	(288)	(84)	(154)
Equity compensation charge - operations	(1)	—	—	(5)	—	—
Segment G&A expenses (excluding equity compensation charge) (2)	(56)	(18)	(63)	(50)	(18)	(52)
Equity compensation charge - general and administrative	(11)	(4)	(8)	(19)	(8)	(17)
Equity earnings in unconsolidated entities	5	9	—	5	10	—
Reported segment profit	$ 445	$ 153	$ 221	$ 334	$ 110	$ 269
Selected items impacting comparability of segment profit (3):						
Equity compensation charge (4)	11	3	7	22	6	16
Inventory valuation adjustments net of related (gains)/losses from derivative activities (5) (6)	—	—	11	—	—	—
(Gains)/losses from derivative activities (5) (7)	—	—	(4)	—	—	27
Net loss on foreign currency revaluation	—	—	21	—	—	—
Gain on sale of linefill	—	—	—	—	—	(12)
Segment profit excluding selected items impacting comparability	$ 456	$ 156	$ 256	$ 356	$ 116	$ 300
Maintenance capital	$ 54	$ 23	$ 4	$ 34	$ 10	$ 6

(1) Includes intersegment amounts.

(2) Segment general and administrative expenses (G&A) reflect direct costs attributable to each segment and an allocation of other expenses to the segments based on the business activities that existed at that time. The proportional allocations by segment require judgment by management and will continue to be based on the business activities that exist during

each period.

(3) Excludes deferred income tax expense and the gains on Rainbow acquisition-related foreign currency and linefill hedges as they do not impact segment profit.

(4) The equity compensation benefit for the three months and charge for the twelve months ended December 31, 2008 and 2007 excludes the portion of the equity compensation expense represented by grants under the LTIP Plans that, pursuant to the terms of the grant, will be settled in cash only and have no impact on diluted units. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans for the three months and year ended December 31, 2008 is less than $1 million and approximately $3 million, respectively. The portion of the equity compensation expense attributable to the cash portion of the LTIP Plans for the three months and twelve months ended December 31, 2007 is $1 million and $5 million, respectively.

(5) Beginning with the first quarter of 2008, gains and losses from derivative activities related to revalued inventory are included in the line item "Inventory valuation adjustments net of gains and losses from related derivative activities"; gains and losses from derivative activities not related to revalued inventory are included in the line item "Gains and losses from derivative activities".

(6) Includes a net inventory valuation adjustment of $81 million and $146 million for the three months and twelve months ended December 31, 2008, respectively. Also includes gains from related derivative activities of $65 million and $134 million for the three months and twelve months ended December 31, 2008, respectively.

(7) The gain from derivative activities for both the three months and twelve months ended December 31, 2008 includes a $3 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The loss from derivative activities for the three months and twelve months ended December 31, 2007 includes a $2 million gain and $3 million gain, respectively, related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

Adjusted segment profit for the Transportation segment for the fourth quarter and full year of 2008 increased 40% and 28%, respectively, over corresponding 2007 results due principally to contributions from the Partnership's Rainbow Pipe Line acquisition, which closed in May 2008, higher average tariffs, an increase in pipeline loss allowance revenue and the impact of a gain related to linefill, partially offset by higher operating expenses.

Adjusted segment profit for the Facilities segment for the fourth quarter and full year of 2008 increased 44% and 34%, respectively, over comparable 2007 metrics primarily due to capacity increases resulting from expansions at the Cushing, St. James and Martinez facilities and the contributions of LPG storage facility acquisitions.

Adjusted segment profit for the Marketing segment for the fourth quarter of 2008 was $58 million representing a 35% increase over the comparable 2007 metrics. The fourth-quarter 2008 results reflect improved gathering margins. The fourth-quarter 2007 results were negatively impacted by the transitional effects of a change in the crude oil market structure. Full-year 2008 adjusted segment profit decreased by 15% from comparable 2007 metrics. Lease gathering margins were stronger in 2008 than 2007. However, the 2007 results benefited from a contango crude oil market structure (which existed during the first half of the year), favorable crude oil differentials and favorable LPG margins.

The Partnership's basic weighted average units outstanding for the fourth quarter of 2008 totaled 123 million (124 million diluted) as compared to 116 million (117 million diluted) in last year's fourth quarter. At December 31, 2008, the Partnership had approximately 123 million units outstanding, long-term debt of approximately $3.3 billion and a long-term debt-to-total capitalization ratio of 48%.

The Partnership has declared a quarterly distribution of $0.8925 per unit ($3.57 per unit on an annualized basis) payable February 13, 2009 on its outstanding limited partner units. This distribution payment represents an increase of approximately 5% over the quarterly distribution of $0.85 per unit paid in February 2008 and is unchanged from the November 2008 distribution level.

Prior to its February 12 conference call, the Partnership will furnish a current report on Form 8-K, which will include material in this press release and financial and operational guidance for the first quarter and full year 2009. A copy of the Form 8-K will be available on the Partnership's website at www.paalp.com.

Non-GAAP Financial Measures

In this release, the Partnership's EBITDA disclosure is not presented in accordance with generally accepted accounting principles and is not intended to be used in lieu of GAAP presentations of net income or cash flows from operating activities. EBITDA is presented because we believe it provides additional information with respect to both the performance of our fundamental business activities as well as our ability to meet our future debt service, capital expenditures and working capital requirements. We also believe that debt holders commonly use EBITDA to analyze Partnership performance. In addition, we present selected items that impact the comparability of our operating results as additional information that may be helpful to your understanding of our financial results. We consider an understanding of these selected items impacting comparability to be material to our evaluation of our operating results and prospects. Although we present selected items that we consider in evaluating our performance, you should also

be aware that the items presented do not represent all items that affect comparability between the periods presented. Variations in our operating results are also caused by changes in volumes, prices, exchange rates, mechanical interruptions, acquisitions and numerous other factors. These types of variations are not separately identified in this release, but will be discussed, as applicable, in management's discussion and analysis of operating results in our Annual Report on Form 10-K.

A reconciliation of EBITDA to net income and cash flows from operating activities for the periods presented is included in the tables attached to this release. In addition, the Partnership maintains on its website (www.paalp.com) a reconciliation of all non-GAAP financial information, such as EBITDA, to the most comparable GAAP measures. To access the information, investors should click on the "Investor Relations" link on the Partnership's home page and then the "Non-GAAP Reconciliation" link on the Investor Relations page.

Conference Call

The Partnership will host a conference call at 11:00 AM (Eastern) on Thursday, February 12, 2009 to discuss the following items:

1. The Partnership's performance for the three and twelve months ended December 31, 2008;
2. The status of major expansion projects;
3. Capitalization and liquidity;
4. Financial and operating guidance for the first quarter and full year 2009; and
5. The Partnership's outlook for the future.

Webcast Instructions

To access the Internet webcast, please go to the Partnership's website at www.paalp.com, choose "Investor Relations," and then choose "Conference Calls." Following the live webcast, the call will be archived for a period of sixty (60) days on the Partnership's website.

If you are unable to participate in the webcast, please dial 877-709-8150, or, for international callers, 201-689-8354, at approximately 10:55 AM (Eastern). No password or reservation number is required. You may access the slide presentation accompanying the conference call a few minutes prior to the call under the Conference Call Summaries portion of the Conference Calls tab of the Investor Relations section of PAA's website at www.paalp.com.

Telephonic Replay Instructions

To listen to a telephonic replay of the conference call, please dial 877-660-6853, or, for international callers, 201-612-7415, and enter account number 232 and replay ID number 270348. The replay will be available beginning Thursday, February 12, 2009, at approximately 1:00 PM (Eastern) and continue until 11:59 PM (Eastern) Thursday, March 12, 2009.

Plains All American Pipeline, L.P. is a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil, refined products and liquefied petroleum gas and other natural gas related petroleum products. Through its 50% ownership in PAA/Vulcan Gas Storage LLC, the partnership is also engaged in the development and operation of natural gas storage facilities. The Partnership is headquartered in Houston, Texas.

Forward Looking Statements

Except for the historical information contained herein, the matters discussed in this news release are forward-looking statements that involve certain risks and uncertainties that could cause actual results to differ materially from results anticipated in the forward-looking statements. These risks and uncertainties include, among other things: 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 success 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; unanticipated changes in crude oil market structure and volatility (or lack thereof); the impact of current and future laws, rulings, governmental regulations and 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 deteriorated 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.

CONSOLIDATED STATEMENTS OF OPERATIONS
(In millions, except per unit data)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007
REVENUES	$ 4,943	$ 6,447	$ 30,061	$ 20,394
COSTS AND EXPENSES				
Purchases and related costs	4,550	6,116	28,479	19,001
Field operating costs	159	136	617	531
General and administrative expenses	31	36	160	164
Depreciation and amortization	61	45	211	180
Total costs and expenses	4,801	6,333	29,467	19,876
OPERATING INCOME	142	114	594	518
OTHER INCOME/(EXPENSE)				
Equity earnings in unconsolidated entities	4	3	14	15
Interest expense	(53)	(41)	(196)	(162)
Interest income and other income (expense), net	6	2	33	10
Income before tax	99	78	445	381
Current income tax expense	—	(1)	(9)	(3)
Deferred income tax expense	(1)	—	1	(13)
NET INCOME	$ 98	$ 77	$ 437	$ 365
NET INCOME - LIMITED PARTNERS	$ 69	$ 55	$ 325	$ 286
NET INCOME - GENERAL PARTNER	$ 29	$ 22	$ 112	$ 79
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.56	$ 0.48	$ 2.70	$ 2.54
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.56	$ 0.47	$ 2.67	$ 2.52
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	123	116	120	113
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	124	117	121	114

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OPERATING DATA [1]	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007
Transportation activities (Average Daily Volumes, thousands of barrels):				
Tariff activities				
All American	45	45	45	47
Basin	394	368	377	378
Capline	222	242	219	235
Line 63/Line 2000	135	168	147	175
Salt Lake City Area Systems [2]	88	99	93	101
West Texas/New Mexico Area Systems [2]	386	350	372	369
Manito	71	70	70	73
Rainbow	192	N/A	129	N/A
Rangeland	58	59	58	63
Refined products	105	107	109	109
Other	1,233	1,250	1,232	1,162
Tariff activities total	2,929	2,758	2,851	2,712

Trucking	101	101	97	105
Transportation activities total	3,030	2,859	2,948	2,817
Facilities activities (Average Monthly Volumes):				
Crude oil, refined products, and LPG storage (average monthly capacity in millions of barrels)	55	50	53	46
Natural gas storage, net to our 50% interest (average monthly capacity in billions of cubic feet)	16	13	14	13
LPG processing (average throughput in thousands of barrels per day)	17	16	17	18
Facilities activities total (average monthly capacity in millions of barrels) [3]	58	52	56	48
Marketing activities (Average Daily Volumes, thousands of barrels):				
Crude oil lease gathering	645	672	658	685
Refined products	33	14	26	11
LPG sales	157	123	103	90
Waterborne foreign crude imported	66	59	80	71
Marketing activities total	901	868	867	857

[1] 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.
[2] The aggregate of multiple systems in the respective areas. The volumes for the West Texas/New Mexico Area Systems for the three and twelve months ended December 31, 2007 previously included amounts for the Mesa system, which has been reclassified to “Other” for all periods presented.
[3] In order to calculate total facilities activities volume add: (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.

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

CONDENSED CONSOLIDATED BALANCE SHEET DATA
(In millions)

	December 31, 2008	December 31, 2007
ASSETS		
Current assets	$ 2,596	$ 3,673
Property and equipment, net	5,059	4,419
Pipeline linefill in owned assets	425	284
Long-term inventory	139	74
Investment in unconsolidated entities	257	215
Goodwill	1,210	1,072
Other long-term assets, net	346	169
Total assets	$ 10,032	$ 9,906
LIABILITIES AND PARTNERS’ CAPITAL		
Current liabilities	$ 2,960	$ 3,729
Long-term debt under credit facilities and other	40	1
Senior notes, net of unamortized discount	3,219	2,623
Other long-term liabilities and deferred credits	261	129
Total liabilities	6,480	6,482
Partners’ capital	3,552	3,424
Total liabilities and partners’ capital	$ 10,032	$ 9,906

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COMPUTATION OF BASIC AND DILUTED EARNINGS PER LIMITED PARTNER UNIT

(In millions, except per unit data)

	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Numerator for basic and diluted earnings per limited partner unit:				
Net income	$ 98	$ 77	$ 437	$ 365
Less: General partner's incentive distribution paid	(28)	(21)	(106)	(73)
Subtotal	70	56	331	292
Less: General partner 2% ownership	(1)	(1)	(6)	(6)
Net income available to limited partners	69	55	325	286
Denominator:				
Basic weighted average number of limited partner units outstanding	123	116	120	113
Effect of dilutive securities:				
Weighted average LTIP units	1	1	1	1
Diluted weighted average number of limited partner units outstanding	124	117	121	114
Basic net income per limited partner unit	$ 0.56	$ 0.48	$ 2.70	$ 2.54
Diluted net income per limited partner unit	$ 0.56	$ 0.47	$ 2.67	$ 2.52

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FINANCIAL DATA RECONCILIATIONS

(In millions)

	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Earnings before interest, taxes, depreciation and amortization ("EBITDA")				
Net income reconciliation				
Net income	$ 98	$ 77	$ 437	$ 365
Add: Interest expense	53	41	196	162
Add: Income tax expense	1	1	8	16
Earnings before interest and taxes ("EBIT")	152	119	641	543
Add: Depreciation and amortization	61	45	211	180
EBITDA	$ 213	$ 164	$ 852	$ 723

	Three Months Ended December 31, 2008	Three Months Ended December 31, 2007	Twelve Months Ended December 31, 2008	Twelve Months Ended December 31, 2007
Cash flow from operating activities reconciliation				
EBITDA	$ 213	$ 164	$ 852	$ 723
Current income tax expense	—	(1)	(9)	(3)
Interest expense	(53)	(41)	(196)	(162)
Net change in assets and liabilities, net of acquisitions	414	(289)	166	218
Other items to reconcile to cash flows from operating activities:				
Equity earnings in unconsolidated entities, net of distributions	(1)	(3)	(4)	(14)
Gain on sale of investment assets	—	—	(12)	(4)
(Gain)/loss on sale of linefill	1	(12)	(3)	(12)
Loss on foreign currency revaluation	24	3	22	—
Net cash received for termination of interest rate and foreign currency hedging instruments	17	—	15	—
Equity compensation (benefit)/charge	(2)	7	24	49
Other	3	—	2	1
Net cash provided by (used in) operating activities	$ 616	$ (172)	$ 857	$ 796

	Three Months Ended	Twelve Months Ended

	December 31,		December 31,	
	2008	2007	2008	2007
Funds flow from operations ("FFO")				
Net income	$ 98	$ 77	$ 437	$ 365
Equity earnings in unconsolidated entities, net of distributions	(1)	(3)	(4)	(14)
Depreciation and amortization	61	45	211	180
Deferred income tax expense	1	—	(1)	13
Non-cash amortization of terminated interest rate and foreign currency hedging instruments	—	—	—	1
FFO	159	119	643	545
Maintenance capital	(25)	(19)	(81)	(50)
FFO after maintenance capital	$ 134	$ 100	$ 562	$ 495

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PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
FINANCIAL SUMMARY (unaudited)

FINANCIAL DATA RECONCILIATIONS

(In millions, except per unit data) (continued)

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007
Net income and earnings per limited partner unit excluding selected items impacting comparability				
Net income	$ 98	$ 77	$ 437	$ 365
Selected items impacting comparability	23	3	35	66
Adjusted net income	$ 121	$ 80	$ 472	$ 431
Net income available for limited partners under EITF 03-06	$ 69	$ 55	$ 325	$ 286
Limited partners' 98% of selected items impacting comparability	23	3	34	65
Adjusted limited partners' net income	$ 92	$ 58	$ 359	$ 351
Adjusted basic net income per limited partner unit	$ 0.75	$ 0.50	$ 2.99	$ 3.11
Adjusted diluted net income per limited partner unit	$ 0.74	$ 0.50	$ 2.96	$ 3.09
Basic weighted average units outstanding	123	116	120	113
Diluted weighted average units outstanding	124	117	121	114

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2008	2007	2008	2007
EBITDA excluding selected items impacting comparability				
EBITDA	$ 213	$ 164	$ 852	$ 723
Selected items impacting comparability [(1)]	23	3	35	56
Adjusted EBITDA	$ 236	$ 167	$ 887	$ 779

[(1)] The twelve-month period ended December 31, 2007 excludes deferred income tax expense as it does not impact EBITDA.

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