PART IV

Item 15. *Exhibits and Financial Statement Schedules*

(a) (1) *Financial Statements*

See "Index to the Consolidated Financial Statements" set forth on Page F-1.

(2) *Financial Statement Schedules*

All schedules are omitted because they are either not applicable or the required information is shown in the consolidated financial statements or notes thereto.

(3) *Exhibits*

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	—	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	—	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	—	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	—	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	—	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	—	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).
3.12	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation,

		successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.14	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).
4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.6	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	—	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	—	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).

4.11	—	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	—	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.13	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	—	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	—	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	—	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17		Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	—	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the $6^1/_4$% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed September 28, 2005).
4.19	—	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.20	—	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.21	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	—	Second Amended and Restated Credit Agreement dated as of July 31, 2006 by and among Plains All American Pipeline, L.P., as US Borrower; PMC (Nova Scotia) Company and Plains Marketing Canada, L.P., as Canadian Borrowers; Bank of America, N.A., as Administrative Agent; Bank of America, N.A., acting through its Canada Branch, as Canadian Administrative Agent; Wachovia Bank, National Association and J. P. Morgan Chase Bank, N.A., as Co-Syndication Agents; Fortis Capital

Corp., Citibank, N.A., BNP Paribas, UBS Securities LLC, SunTrust Bank, and The Bank of Nova Scotia, as Co-Documentation Agents; the Lenders party thereto; and Banc of America Securities LLC and Wachovia Capital Markets, LLC, as Joint Lead Arrangers and Joint Book Managers (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 4, 2006).

10.2	—	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.3	—	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.4	—	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.5	—	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.6	—	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.7**	—	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.9**	—	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.10**	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.11**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	—	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).
10.14	—	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.15	—	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco

Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).

10.16	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.17	—	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18**	—	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.19**	—	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.20**	—	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.21**†	—	Directors' Compensation Summary.
10.22	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.23**	—	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.24**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.25**	—	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.26**	—	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	—	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	—	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.29	—	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.30	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.31**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005).
10.32**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16,

2005).

10.33	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.34	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.35**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.36**	—	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.37**	—	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.38**	—	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.39**	—	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.40	—	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P., PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
10.41**	—	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.42**	—	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.43	—	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.44	—	First Amendment to Second Restated Credit Agreement dated as of October 27, 2009, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, SOCIETE GENERALE, as Documentation Agent, Banc of America Securities LLC (“BAS”), BNP Paribas (“BNPP”) and Societe Generale, as joint lead arrangers, BAS and BNPP, as joint bookrunners, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 29, 2009).
10.45	—	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 7, 2008).
10.46	—	Contribution and Assumption Agreement dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed January 4, 2008).
10.47	—	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream

		Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.48**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.49**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.50**	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.51**	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.52**	—	Form of Amendment to LTIP grant letters (executive officers) (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.53**	—	Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2008).
12.1†	—	Computation of Ratio of Earnings to Fixed Charges
21.1†	—	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1†	—	Consent of PricewaterhouseCoopers LLP.
31.1†	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2†	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1†	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2†	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101†	—	The following financial information from the annual report on Form 10-K of Plains All American Pipeline, L.P. for the year ended December 31, 2009, formatted in XBRL (extensible Business Reporting Language): (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Partners' Capital, (v) Consolidated Statements of Comprehensive Income, (vi) Consolidated Statements of Changes in Accumulated Other Comprehensive Income and (vii) Notes to the Consolidated Financial Statements, tagged as blocks of text.

† Filed herewith

** Management compensatory plan or arrangement

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PLAINS ALL AMERICAN PIPELINE, L.P.

By: PAA GP LLC,
its general partner

By: Plains AAP, L.P.,
its sole member

By: PLAINS ALL AMERICAN GP LLC,
its general partner

By: /s/ GREG L. ARMSTRONG
Greg L. Armstrong,
Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)

February 26, 2010

By: /s/ AL SWANSON
Al Swanson,
Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)

February 26, 2010

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ GREG L. ARMSTRONG Greg L. Armstrong	Chairman of the Board, Chief Executive Officer and Director of Plains All American GP LLC (Principal Executive Officer)	February 26, 2010
/s/ HARRY N. PEFANIS Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 26, 2010
/s/ AL SWANSON Al Swanson	Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 26, 2010
/s/ TINA L. SUMMERS Tina L. Summers	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 26, 2010
/s/ EVERARDO GOYANES Everardo Goyanes	Director of Plains All American GP LLC	February 26, 2010
/s/ T. GEOFF MCKAY T. Geoff McKay	Director of Plains All American GP LLC	February 26, 2010
/s/ GARY R. PETERSEN Gary R. Petersen	Director of Plains All American GP LLC	February 26, 2010
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director of Plains All American GP LLC	February 26, 2010
/s/ ARTHUR L. SMITH Arthur L. Smith	Director of Plains All American GP LLC	February 26, 2010
/s/ J. TAFT SYMONDS J. Taft Symonds	Director of Plains All American GP LLC	February 26, 2010
/s/ CHRISTOPHER M. TEMPLE Christopher M. Temple	Director of Plains All American GP LLC	February 26, 2010

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES

INDEX TO THE CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Plains All American Pipeline, L.P.’s management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Management has used the framework set forth in the report entitled “Internal Control—Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) to evaluate the effectiveness of the Partnership’s internal control over financial reporting. Based on that evaluation, management has concluded that the Partnership’s internal control over financial reporting was effective as of December 31, 2009.

The effectiveness of the Partnership’s internal control over financial reporting as of December 31, 2009 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears on Page F-3.

/s/ GREG L. ARMSTRONG

Greg L. Armstrong
Chairman of the Board, Chief Executive Officer and
Director of Plains All American GP LLC
(Principal Executive Officer)

/s/ AL SWANSON

Al Swanson
Senior Vice President and Chief Financial Officer of
Plains All American GP LLC
(Principal Financial Officer)

February 26, 2010

Report of Independent Registered Public Accounting Firm

To the Board of Directors of the General Partner and Unitholders of
Plains All American Pipeline, L.P.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of cash flows, of changes in partners' capital, of comprehensive income, and of changes in accumulated other comprehensive income, present fairly, in all material respects, the financial position of Plains All American Pipeline, L.P. and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Partnership's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Partnership's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Houston, Texas
February 26, 2010

PricewaterhouseCoopers LLP

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

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 25	$ 11
Trade accounts receivable and other receivables, net	2,253	1,525
Inventory	1,157	801
Other current assets	223	259
Total current assets	3,658	2,596
PROPERTY AND EQUIPMENT	7,240	5,727
Accumulated depreciation	(900)	(668)
	6,340	5,059
OTHER ASSETS		
Linefill and base gas	501	425
Long-term inventory	121	139
Investment in unconsolidated entities	82	257
Goodwill	1,287	1,210
Other, net	369	346
Total assets	$ 12,358	$ 10,032
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 2,295	$ 1,507
Short-term debt (Note 4)	1,074	1,027
Other current liabilities	413	426
Total current liabilities	3,782	2,960
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	6	40
Senior notes, net of unamortized net discount of $14 and $6, respectively	4,136	3,219
Other long-term liabilities and deferred credits	275	261
Total long-term liabilities	4,417	3,520
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS' CAPITAL		
Common unitholders (136,135,988 and 122,911,645 units outstanding, respectively)	4,002	3,469
General partner	94	83
Total partners' capital excluding noncontrolling interest	4,096	3,552
Noncontrolling interest	63	—
Total partners' capital	4,159	3,552
Total liabilities and partners' capital	$ 12,358	$ 10,032

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

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

	Year Ended December 31, 2009	2008	2007
REVENUES			
Supply & Logistics segment revenues	$ 17,757	$ 29,348	$ 19,834
Transportation segment revenues	536	556	439
Facilities segment revenues	227	157	121
Total revenues	18,520	30,061	20,394
COSTS AND EXPENSES			
Purchases and related costs	16,656	28,479	19,001
Field operating costs	638	617	531
General and administrative expenses	211	160	164
Depreciation and amortization	236	211	180
Total costs and expenses	17,741	29,467	19,876
OPERATING INCOME	779	594	518
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	15	14	15
Interest expense (net of capitalized interest of $15, $17 and $14, respectively)	(224)	(196)	(162)
Other income, net	16	33	10
INCOME BEFORE TAX	586	445	381
Current income tax expense	(15)	(9)	(3)
Deferred income tax benefit/(expense)	9	1	(13)
NET INCOME	580	437	365
Less: Net income attributable to noncontrolling interest	(1)	—	—
NET INCOME ATTRIBUTABLE TO PLAINS	$ 579	$ 437	$ 365
NET INCOME ATTRIBUTABLE TO PLAINS:			
LIMITED PARTNERS	$ 443	$ 325	$ 286
GENERAL PARTNER	$ 136	$ 112	$ 79
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 3.34	$ 2.66	$ 2.47
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 3.32	$ 2.64	$ 2.45
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	130	120	113
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	131	121	114

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

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

	Year Ended December 31,		
	2009	2008	2007
		(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 580	$ 437	$ 365
Reconciliation of net income to net cash provided by operating activities:			
Depreciation and amortization	236	211	180
Equity compensation charge	68	24	49
Inventory valuation adjustments	—	168	1
Gain on sale of linefill	(4)	(3)	(12)
Gain on sale of investment assets	—	(12)	(4)
Deferred income tax (benefit)/expense	(9)	(1)	13
(Gain)/loss on foreign currency revaluation	(13)	22	—
Equity earnings in unconsolidated entities, net of distributions	(8)	(4)	(14)
Net cash received/(paid) for terminated interest rate and foreign currency hedging instruments	(9)	15	—
Net gain on purchase of remaining 50% interest in PNGS	(9)	—	—
Other	(6)	2	1
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	(744)	668	(739)
Inventory	(319)	(120)	340
Accounts payable and other current liabilities	602	(550)	616
Net cash provided by operating activities	365	857	796
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions, net of cash acquired (Note 3)	(219)	(709)	(127)
Additions to property, equipment and other	(460)	(589)	(548)
Investment in unconsolidated entities	(4)	(37)	(9)
Net cash paid for linefill in assets owned	(9)	(55)	(19)
Cash received for sale of noncontrolling interest in a subsidiary	26	—	—
Proceeds from sales of assets and other	6	51	40
Net cash used in investing activities	(660)	(1,339)	(663)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on revolving credit facilities	(19)	286	305
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	20	(196)	(359)
Repayment of PNGS debt	(446)	—	—
Proceeds from the issuance of senior notes	1,346	597	—
Repayments of senior notes	(430)	—	—
Net proceeds from the issuance of common units (Note 5)	458	315	383
Distributions paid to common unitholders (Note 5)	(468)	(418)	(370)
Distributions paid to general partner (Note 5)	(137)	(114)	(81)
Other financing activities	(12)	(6)	(2)
Net cash provided by/(used in) financing activities	312	464	(124)
Effect of translation adjustment on cash	(3)	5	4
Net increase/(decrease) in cash and cash equivalents	14	(13)	13
Cash and cash equivalents, beginning of period	11	24	11
Cash and cash equivalents, end of period	$ 25	$ 11	$ 24
Cash paid for interest, net of amounts capitalized	$ 214	$ 206	$ 186
Cash paid/(refunded) for income taxes, net	$ (5)	$ 15	$ 3

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN PARTNERS' CAPITAL
(in millions)

	Common Units		General Partner	Partners' Capital Excluding Noncontrolling Interest	Noncontrolling Interest	Partners' Capital
	Units	Amount				
Balance at December 31, 2006	**109**	**$ 2,906**	**$ 71**	**$ 2,977**	**$ —**	**$ 2,977**
Net income	—	286	79	365	—	365
Distributions	—	(370)	(81)	(451)	—	(451)
Issuance of common units	6	375	8	383	—	383
Issuance of common units under Long Term Incentive Plans ("LTIP")	1	17	—	17	—	17
Class B Units of Plains AAP, L.P. (Note 10)	—	2	1	3	—	3
Other comprehensive income	—	127	3	130	—	130
Balance at December 31, 2007	**116**	**$ 3,343**	**$ 81**	**$ 3,424**	**$ —**	**$ 3,424**
Net income	—	325	112	437	—	437
Distributions	—	(418)	(114)	(532)	—	(532)
Issuance of common units	7	309	6	315	—	315
Issuance of common units under LTIP	—	1	—	1	—	1
Class B Units of Plains AAP, L.P. (Note 10)	—	12	—	12	—	12
Other comprehensive loss	—	(103)	(2)	(105)	—	(105)
Balance at December 31, 2008	**123**	**$ 3,469**	**$ 83**	**$ 3,552**	**$ —**	**$ 3,552**
Sale of noncontrolling interest in a subsidiary	—	(37)	(1)	(38)	64	26
Net income	—	443	136	579	1	580
Distributions	—	(468)	(137)	(605)	—	(605)
Issuance of common units	11	447	9	456	—	456
Issuance of common units in connection with the PNGS Acquisition	2	91	2	93	—	93
Issuance of common units under LTIP	—	12	—	12	—	12
Class B Units of Plains AAP, L.P. (Note 10)	—	2	3	5	—	5
Distribution to noncontrolling interest	—	—	—	—	(2)	(2)
Other comprehensive income	—	46	2	48	—	48
Other	—	(3)	(3)	(6)	—	(6)
Balance at December 31, 2009	**136**	**$ 4,002**	**$ 94**	**$ 4,096**	**$ 63**	**$ 4,159**

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(in millions)

	Year Ended December 31, 2009	2008	2007
Net income attributable to Plains	$ 579	$ 437	$ 365
Other comprehensive income/(loss)	48	(105)	130
Comprehensive income	$ 627	$ 332	$ 495

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

	Derivative Instruments	Translation Adjustments	Other	Total
Balance at December 31, 2006	$ (20)	$ 70	$ —	$ 50
Reclassification adjustments	11	—	—	11
Net deferred gain on cash flow hedges	13	—	—	13
Currency translation adjustment	—	106	—	106
2007 Activity	24	106	—	130
Balance at December 31, 2007	$ 4	$ 176	$ —	$ 180
Reclassification adjustments	46	—	—	46
Net deferred gain on cash flow hedges	111	—	—	111
Currency translation adjustment	—	(262)	—	(262)
2008 Activity	157	(262)	—	(105)
Balance at December 31, 2008	$ 161	$ (86)	$ —	$ 75
Reclassification adjustments	8	—	—	8
Net deferred loss on cash flow hedges	(151)	—	—	(151)
Currency translation adjustment	—	192	—	192
Proportionate share of our unconsolidated entities' other comprehensive loss	—	—	(1)	(1)
2009 Activity	(143)	192	(1)	48
Balance at December 31, 2009	$ 18	$ 106	$ (1)	$ 123

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Organization and Basis of Presentation

Organization

Plains All American Pipeline, L.P. is a Delaware limited partnership formed in 1998. Our operations are conducted directly and indirectly through our primary operating subsidiaries. As used in this Form 10-K, the terms "Partnership," "Plains," "we," "us," "our," "ours" and similar terms refer to Plains All American Pipeline, L.P. and its subsidiaries, unless the context indicates otherwise.

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." We are also engaged in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Supply and Logistics. We previously referred to the Supply and Logistics segment as the Marketing segment. We revised the segment name to better describe the business activities conducted within that segment. See Note 15 for further discussion of our three operating segments.

Our 2% general partner interest is held by PAA GP LLC, a Delaware limited liability company, whose sole member is Plains AAP, L.P., a Delaware limited partnership. Plains All American GP LLC, a Delaware limited liability company, is Plains AAP, L.P.'s general partner. Plains All American GP LLC manages our operations and activities and employs our domestic officers and personnel. Our Canadian officers and personnel are employed by our subsidiary PMC (Nova Scotia) Company, the general partner of Plains Marketing Canada, L.P. 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. Plains AAP, L.P. and Plains All American GP LLC are essentially held by 13 owners with interests ranging from approximately 50% to less than 1%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present and discuss our consolidated financial position as of December 31, 2009 and 2008, and the consolidated results of our operations, cash flows, changes in partners' capital, comprehensive income and changes in accumulated other comprehensive income for the years ended December 31, 2009, 2008 and 2007. All significant intercompany transactions have been eliminated in consolidation, and certain reclassifications have been made to information from previous years to conform to the current presentation. These reclassifications do not affect net income. The accompanying consolidated financial statements include Plains and all of its wholly owned subsidiaries. Investments in entities over which we have significant influence but not control are accounted for by the equity method. We evaluate our equity investments for impairment in accordance with Financial Accounting Standards Board ("FASB") guidance with respect to the equity method of accounting for investments in common stock. An impairment of an equity investment results when factors indicate that the investment's fair value is less than its carrying value and the reduction in value is other than temporary in nature.

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

Note 2—Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. We make significant estimates with respect to (i) purchases and sales accruals, (ii) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (iii) mark-to-market gains and losses on derivative instruments (pursuant to guidance issued by the FASB regarding fair value measurements), (iv) accruals and contingent liabilities, (v) equity compensation plan accruals, (vi) property, plant and equipment and depreciation expense and (vii) allowance for doubtful accounts. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Revenue Recognition

Supply and Logistics Segment Revenues. Revenues from sales of crude oil, LPG and refined products are recognized at the time title to the product sold transfers to the purchaser, which occurs upon delivery of the product to the purchaser or its designee. Sales of crude oil, LPG and refined products consist of outright sales contracts and buy/sell arrangements as well as exchanges. Also, inventory purchases and sales under buy/sell transactions are treated as inventory exchanges and are presented net within Supply and Logistics segment revenues in our consolidated statements of operations.

Additionally, we may utilize derivatives in connection with the transactions described above. For commodity derivatives that are designated as cash flow hedges, derivative gains and losses are deferred to Accumulated Other Comprehensive Income ("AOCI") and recognized in revenues in the periods during which the underlying physical hedged transaction impacts earnings. For derivatives that do not qualify for hedge accounting or are not designated for hedge accounting, as well as ineffectiveness associated with cash flow hedges, are recognized in revenues each period.

Transportation Segment Revenues. Revenues from pipeline tariffs and fees are associated with the transportation of crude oil and refined products at a published tariff as well as revenues associated with line leases for committed space on a particular system that may or may not be utilized. Tariff revenues are recognized either at the point of delivery or at the point of receipt pursuant to specifications outlined in the regulated and non-regulated tariffs. Revenues associated with line-lease fees are recognized in the month to which the lease applies, whether or not the space is actually utilized and are subject to make up rights for take or pay arrangements. All pipeline tariff and fee revenues are based on actual volumes and rates. As is common in the industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We value the variance of allowance volumes to actual losses at the estimated net realizable value (including the impact of gains and losses from derivative related activities) at the time the variance occurred and the result is recorded as either an increase or decrease to tariff revenues. In addition, we have certain agreements that require counterparties to ship a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume is shipped (pursuant to specifications outlined in the tariffs) or when the counterparty's ability to make up the minimum volume has expired.

Facilities Segment Revenues. Storage and terminalling revenues include (i) storage fees that are generated when we lease storage capacity, (ii) terminalling fees, or throughput fees, that are generated when we receive crude oil, refined products, LPG or natural gas from one connecting pipeline and redeliver the applicable product to another connecting carrier, (iii) hub service fees for the movement of natural gas across our header systems and (iv) fees from LPG fractionation and isomerization services. We generate revenue through a combination of month-to-month and multi-year leases and processing arrangements. Storage fees resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. Terminal fees are recognized as the crude oil, LPG or refined product exits the terminal and is delivered to the connecting carrier or third-party terminal. Hub service fees are recognized in the period the natural gas moves across our header system. In addition, we have certain agreements that require counterparties to throughput a minimum volume over an agreed upon period. Revenue is recognized at the latter of when the volume exits the terminal or when the counterparty's ability to make up the minimum volume has expired.

Purchases and Related Costs

Purchases and related costs include (i) the cost of crude oil, LPG and refined products obtained in outright purchases; (ii) fees incurred for third-party transportation and storage, whether by pipeline, truck, ship or barge; (iii) interest cost attributable to borrowings for inventory stored in a contango market; (iv) performance-related bonus accruals; and (v) expenses of issuing letters of credit to support these purchases. These costs are recognized when incurred except in the case of products purchased, which are recognized at the time title transfers to us.

Field Operating Costs and General and Administrative Expenses

Field operating costs consist of various field operating expenses, including fuel and power costs, telecommunications, payroll and benefit costs (including equity compensation expense) for truck drivers and field personnel, maintenance and integrity management costs, regulatory compliance, environmental remediation, insurance, vehicle leases, and property taxes. General and administrative expenses consist primarily of payroll and benefit costs (including equity compensation expense), certain information system and legal costs, office rent, contract and consultant costs and audit and tax fees.

Foreign Currency Transactions

Certain of our subsidiaries are based in Canada and use the Canadian dollar as their functional currency. Assets and liabilities of subsidiaries with a Canadian dollar functional currency are translated at period-end rates of exchange, and revenues and expenses are translated at average exchange rates prevailing for each month. The resulting translation adjustments are made directly to a separate component of other comprehensive income in Partners' Capital reflected on our consolidated balance sheet.

Certain of our subsidiaries also enter into transactions and have monetary assets and liabilities that are denominated in a currency other than the entities' respective functional currencies. Gains and losses from the revaluation of foreign currency transactions and monetary assets and liabilities are included in the consolidated statements of operations. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a gain of approximately $13 million for the year ended December 31, 2009, a loss of approximately $22 million for the year ended December 31, 2008 and a gain of less than $1 million for the year ended December 31, 2007.

Cash and Cash Equivalents

Cash and cash equivalents consist of all demand deposits and funds invested in highly liquid instruments with original maturities of three months or less and typically exceed federally insured limits. We periodically assess the financial condition of the institutions where these funds are held and believe that our credit risk is minimal. In accordance with our policy, outstanding checks are classified as accounts payable rather than negative cash. As of December 31, 2009 and 2008, accounts payable included approximately $50 million and $44 million, respectively, of outstanding checks that were reclassified from cash and cash equivalents.

Accounts Receivable

Our accounts receivable are primarily from purchasers and shippers of crude oil and, to a lesser extent, purchasers of LPG, refined products and natural gas storage. These purchasers include, but are not limited to refineries, producers, 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 crude oil supply and logistics activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

During the last two years, U.S. and world financial markets and energy prices were extremely volatile and global economies substantially weakened. This financial market volatility combined with the fluctuation in energy prices experienced over the past two years has caused liquidity issues impacting many companies, which in turn have increased the potential credit risks associated with certain counterparties with which we do business.

To mitigate such credit risks, we have in place a rigorous credit review process. We closely monitor these conditions in order to make a determination with respect to the amount, if any, of credit to be extended to any given customer and the form and amount of financial performance assurances we require. Such financial assurances are commonly provided to us in the form of standby letters of credit, "parental" guarantees or advance cash payments. At December 31, 2009 and 2008, we had received approximately $212 million and $66 million, respectively, of advance cash payments from third parties to mitigate credit risk. In addition, we enter into netting arrangements with our counterparties. These arrangements cover a significant part 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 December 31, 2009 and 2008, substantially all of our net accounts receivable were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $9 million and $5 million at December 31, 2009 and 2008, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Inventory, Linefill, Base Gas and Long-term Inventory

Inventory primarily consists of crude oil, LPG, refined products and natural gas in pipelines, storage facilities and rail cars that are valued at the lower of cost or market, with cost determined using an average cost method within specific inventory pools.

At the end of each reporting period we assess the carrying value of our inventory and make any adjustments necessary to reduce the carrying value to the applicable net realizable value. During 2008 and 2007, we recorded non-cash charges of approximately $168 million and $1 million, respectively, related to the writedown of such inventory. During 2009, no such writedowns were recognized. Linefill, base gas and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil, LPG and natural gas. (See Note 3 for the fair value of assets and liabilities recognized as part of the PNGS acquisition.) Linefill is used to pack the pipeline such that when an incremental product is injected into or enters a pipeline it forces product out at another location. Base gas requirements of natural gas, as well as the minimum amount of crude oil and refined products is used to operate our storage and terminalling facilities, similar to linefill in the pipelines. During 2009, 2008 and 2007, we recorded gains of approximately $4 million, $3 million and $12 million, respectively, on the sale of pipeline linefill for proceeds of approximately $24 million, $23 million and $20 million, respectively.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that is needed for our commercial operations are included within specific inventory pools in Inventory (a current asset) in determining the average cost of operating inventory. At the end of each period, we reclassify the inventory not expected to be liquidated within the succeeding twelve months out of inventory, at average cost, and into long-term inventory, which is reflected as a separate line item within other assets on the consolidated balance sheet.

Inventory, linefill, base gas and long term inventory consisted of the following (barrels in thousands, cubic feet in millions and total value in millions):

	December 31, 2009				December 31, 2008			
	Volumes	Unit of Measure	Total Value	Price/ Unit (1)	Volumes	Unit of Measure	Total Value	Price/ Unit (1)
Inventory								
Crude oil	12,232	barrels	$ 886	$ 72.43	9,986	barrels	$ 421	$ 42.16
LPG	6,051	barrels	247	$ 40.82	7,748	barrels	370	$ 47.75
Refined products	283	barrels	21	$ 74.20	103	barrels	5	$ 48.54
Natural gas (2) (3)	181	cubic feet	1	$ 3.30	—	cubic feet	—	N/A
Parts and supplies	N/A		2	N/A	N/A		5	N/A
Inventory subtotal			1,157				801	
Linefill and base gas								
Crude oil	9,404	barrels	471	$ 50.09	9,148	barrels	422	$ 46.13
Natural gas (2) (3)	9,194	cubic feet	28	$ 3.04	—	cubic feet	—	N/A
LPG	52	barrels	2	$ 38.46	67	barrels	3	$ 44.78
Linefill and base gas subtotal			501				425	
Long-term inventory								
Crude oil	1,497	barrels	103	$ 68.80	1,781	barrels	121	$ 67.94
LPG	458	barrels	18	$ 39.30	363	barrels	18	$ 49.59
Long-term inventory subtotal			121				139	
Total			$ 1,779				$ 1,365	

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

(2) To account for the 6:1 mcf of natural gas to crude oil barrel ratio, the natural gas volumes can be converted to barrels by dividing by 6.

(3) In September 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC (“PNGS”). We historically accounted for our 50% indirect interest in PNGS under the equity method. As such, we did not have direct ownership of PNGS’s natural gas inventory or base gas. See Note 3 to our Consolidated Financial Statements for additional discussion regarding the PNGS acquisition.

Property, Plant and Equipment

In accordance with our capitalization policy, costs associated with acquisitions and improvements that expand our existing capacity, including related interest costs, are capitalized. For the years ended December 31, 2009, 2008 and 2007, capitalized interest was $15 million, $17 million and $14 million, respectively. We also capitalize expenditures for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production, and/or functionality of our existing assets. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are expensed as incurred.

Property, plant and equipment, net is stated at cost and consisted of the following (in millions):

	Estimated Useful Lives (Years)	December 31, 2009	December 31, 2008
Crude oil pipelines and facilities	30 - 50	$ 4,535	$ 3,934
Storage and terminal facilities	30 - 70	1,735	944
Trucking equipment and other	5 - 15	331	255
Construction in progress	—	476	474
Office property and equipment	3 - 5	84	75
Land and other	N/A	79	45
		7,240	5,727
Less accumulated depreciation		(900)	(668)
Property and equipment, net		$ 6,340	$ 5,059

Depreciation expense for the years ended December 31, 2009, 2008 and 2007 was $216 million, $196 million and $160 million, respectively.

We calculate our depreciation using the straight-line method, based on estimated useful lives and salvage values of our assets. These estimates are based on various factors including age and condition (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions and supply and demand in the area. When assets are put into service, we make estimates with respect to useful lives and salvage values that we believe are reasonable. However, subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year. Also, gains and losses on sales of assets and asset impairments are included as a component of depreciation and amortization in the consolidated statements of operations.

Equity Method of Accounting

Our investments in Frontier Pipeline Company (“Frontier”), Settoon Towing, LLC (“Settoon Towing”) and Butte Pipe Line Company (“Butte”) are accounted for under the equity method of accounting. Our ownership interests in Frontier, Settoon Towing and Butte are 22%, 50% and 22%, respectively. We do not consolidate any part of the assets or liabilities of our equity investees. Our share of net income or loss is reflected as one line item on the income statement and will increase or decrease, as applicable, the carrying value of our investments on the balance sheet. In addition, we include a proportionate share of our equity method investees’ unrealized gains and losses in other comprehensive income on our consolidated balance sheet. We also adjust our investment balances in these investees by the like amount. Distributions to the Partnership will reduce the carrying value of our investments and will be reflected on our cash flow statement netted against equity in earnings. In turn, contributions will increase the carrying value of our investments and will be reflected on our cash flow statement within investing activities.

Noncontrolling Interest

We account for noncontrolling interests in subsidiaries in accordance with FASB guidance specific to noncontrolling interests. FASB guidance requires all entities to report noncontrolling interests in subsidiaries (formerly referred to as minority interest) as a component of equity in the consolidated financial statements. Noncontrolling interest represents the portion of assets and liabilities in a subsidiary that is owned by a third-party. See Note 5 for additional discussion regarding our noncontrolling interests.

Asset Retirement Obligations

FASB guidance establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (i) the time of the liability recognition, (ii) initial measurement of the liability, (iii) allocation of asset retirement cost to expense, (iv) subsequent measurement of the liability and (v) financial statement disclosures. FASB guidance also requires that the cost for asset retirement should be capitalized as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method.

Some of our assets, primarily related to our transportation and facilities segments, have contractual or regulatory obligations to perform remediation and, in some instances, dismantlement and removal activities when the assets are abandoned. These obligations include varying levels of activity including disconnecting inactive assets from active assets, cleaning and purging assets, and in some cases, completely removing the assets and returning the land to its original state. These assets have been in existence for many years and with regular maintenance will continue to be in service for many years to come. It is not possible to predict when demand for these transportation or storage services will cease and we do not believe that such demand will cease for the foreseeable future. Accordingly, we believe the date when these assets will be abandoned is indeterminate. With no reasonably determinable abandonment date, we cannot reasonably estimate the fair value of the associated asset retirement obligations. We will record asset retirement obligations for these assets in the period in which sufficient information becomes available for us to reasonably determine the settlement dates.

A small portion of our contractual or regulatory obligations is related to assets that are inactive or that we plan to take out of service and, although the ultimate timing and costs to settle these obligations are not known with certainty, we have recorded a reasonable estimate of these obligations. We have estimated that the fair value of these obligations was approximately $5 million at December 31, 2009 and 2008.

Impairment of Long-Lived Assets

Long-lived assets with recorded values that are not expected to be recovered through future cash flows are written down to estimated fair value in accordance with FASB guidance with respect to the accounting for the impairment or disposal of long-lived assets. Under this guidance, a long-lived asset is tested for impairment when events or circumstances indicate that its carrying value may not be recoverable. The carrying value of a long-lived asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. If the carrying value exceeds the sum of the undiscounted cash flows, an impairment loss equal to the amount by which the carrying value exceeds the fair value of the asset is recognized.

We periodically evaluate property, plant and equipment for impairment when events or circumstances indicate that the carrying value of these assets may not be recoverable. The evaluation is highly dependent on the underlying assumptions of related cash flows. The subjective assumptions used to determine the existence of an impairment in carrying value include:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of “holding” versus “selling” an asset;
- the forecast of undiscounted expected future cash flow over the asset’s estimated useful life; and
- if an impairment exists, the fair value of the asset or asset group.

During 2009, we recognized impairments of less than $1 million for assets taken out of service. Impairments of approximately $5 million and less than $1 million were recognized during 2008 and 2007, respectively, and were predominantly related to assets that were taken out of service. These assets did not support spending the capital necessary to continue service and we utilized other assets to handle these activities.

Goodwill

In accordance with FASB guidance, we test goodwill at least annually (as of June 30) and on an interim basis if a triggering event occurs, such as an adverse change in business climate, to determine whether an impairment has occurred. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. A reporting unit is an operating segment or one level below an operating segment for which discrete financial information is available and regularly reviewed by segment management. Our reporting units are our operating segments. FASB guidance requires a two step approach to testing goodwill for impairment. In Step 1, we compare the fair value of the reporting unit with the respective book values, including goodwill, by using an income approach based on a discounted cash flow analysis. This approach requires us to make long-term forecasts of future revenues, expenses and other expenditures. Those forecasts require the use of various assumptions and estimates, the most significant of which are net revenues (total revenues less purchases and related costs), operating expenses, general and administrative expenses and the weighted-average cost of capital. Fair value of the reporting units is determined using significant unobservable inputs, or level 3 inputs in the fair value hierarchy. When the fair value is greater than book value, then the reporting unit's goodwill is not considered impaired. If the book value is greater than fair value, then we proceed to Step 2. In Step 2, we compare the implied fair value of the reporting unit's goodwill with the book value. A goodwill impairment loss is recognized if the carrying amount exceeds its fair value.

In addition, there is a potential indicator of impairment if a company's market capitalization is less than its book equity. Periodically, we compare our market capitalization to our book equity to determine if there is an indicator of potential impairment. Throughout 2009, our market capitalization exceeded the book value of our equity and thus, this indicated that there was no triggering event. There were no other indicators of potential impairment of our goodwill during 2009.

Through Step 1 of our annual testing of goodwill for potential impairment, we determined that the fair value of each reporting unit was greater than its respective book value, and therefore goodwill was not considered impaired. We will continue to monitor various potential indicators (including the financial markets) to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. We have not recognized any impairment of goodwill during the last three years.

The table below reflects our changes in goodwill (in millions):

	Transportation	Facilities	Supply & Logistics	Total [1]
Balance at December 31, 2007	**$ 404**	**$ 283**	**$ 385**	**$ 1,072**
2008 Goodwill Related Activity:				
Rainbow acquisition	194	—	—	194
Purchase accounting adjustments [2]	—	—	(12)	(12)
Foreign currency translation adjustments	(36)	—	(8)	(44)
Balance at December 31, 2008	**$ 562**	**$ 283**	**$ 365**	**$ 1,210**
2009 Goodwill Related Activity:				
PNGS acquisition	—	25	—	25
Other acquisitions	24	—	—	24
Purchase accounting adjustments [2]	(3)	—	—	(3)
Foreign currency translation adjustments	25	—	6	31
Balance at December 31, 2009	**$ 608**	**$ 308**	**$ 371**	**$ 1,287**

(1) As of December 31, 2009, we do not have any accumulated impairment losses.

(2) Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation. This preliminary goodwill balance may be adjusted when the purchase price allocation is finalized. See Note 3 for additional discussion of our acquisitions.

Other Assets, Net

Other assets, net of accumulated amortization consist of the following (in millions):

	2009	2008
Debt issue costs	$ 42	$ 34
Fair value of derivative instruments	77	148
Intangible assets	239	191
Other	65	10
	423	383
Less accumulated amortization	(54)	(37)
	$ 369	$ 346

Costs incurred in connection with the issuance of long-term debt and amendments to our credit facilities are capitalized and amortized using the straight-line method over the term of the related debt. Use of the straight-line method does not differ materially from the "effective interest" method of amortization. Fully amortized debt issue costs and the related accumulated amortization are written off in conjunction with the refinancing or termination of the applicable debt arrangement. We capitalized debt issue costs of approximately $12 million and $7 million in 2009 and 2008, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for the three years ended December 31, 2009, 2008 and 2007 was $19 million, $21 million and $13 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2009, 2008 and 2007 was $14 million, $15 million and $10 million, respectively.

Intangible assets that have finite lives are tested for impairment when events or circumstances indicate that the carrying value may not be recoverable. Our intangible assets that have finite lives consist of the following (in millions):

		December 31, 2009			December 31, 2008		
	Estimated Useful Lives (Years)	Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
Customer contracts and relationships	1-30	$ 171	$ (36)	$ 135	$ 151	$ (24)	$ 127
Emission reduction credits [1]	N/A	45	—	45	40	—	40
Property tax abatement	13	23	(1)	22	—	—	—
		$ 239	$ (37)	$ 202	$ 191	$ (24)	$ 167

(1) Emission reduction credits are finite lived and are subject to amortization from the date that they are first utilized. At December 31, 2009, none of our emission reduction credits were being utilized because the projects for which they were acquired are not in service.

We estimate that our amortization expense related to finite-lived intangible assets for the next five years will be as follows (in millions):

2010	$ 14
2011	$ 11
2012	$ 10
2013	$ 10
2014	$ 10

Environmental Matters

We record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our recording of these accruals coincides with our completion of a feasibility study or our commitment to a formal plan of action. We also record receivables for amounts recoverable from insurance or from third parties under indemnification agreements in the period that we determine the costs are probable of recovery.

We expense expenditures that relate to an existing condition caused by past operations that do not contribute to current or future profitability. We record environmental liabilities assumed in business combinations based on the estimated fair value of the environmental obligations caused by past operations of the acquired company. See Note 12 for further discussion of environmental remediation matters.

Income and Other Taxes

See Note 7 for discussion of U.S. federal and state taxes and Canadian federal and provincial taxes.

We estimate (i) income taxes in the jurisdictions in which we operate, (ii) net deferred tax assets and liabilities based on temporary differences that are expected to be recovered or settled at the enacted tax rates expected in future periods, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to our current tax positions. We have not recorded a valuation allowance against our deferred tax assets as we believe that it is more likely than not that they will be realized.

We adopted the provisions of the FASB guidance related to accounting for uncertainty in income taxes on January 1, 2007. Pursuant to this guidance, we must recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities, based on the technical merits of the tax position and also the past administrative practices and precedents of the taxing authority. As of December 31, 2009 and 2008, we have not recognized any material amounts in connection with uncertainty in income taxes.

Recent Accounting Pronouncements

In June 2009, the FASB issued guidance to establish the source of authoritative generally accepted accounting principles to be applied by nongovernmental entities in the preparation of financial statements. As this guidance is meant to establish the source of authoritative GAAP and to better organize current accounting guidance, it only affects the referencing to applicable guidance throughout the accompanying consolidated financial statements and the notes thereto. This guidance was effective for interim or annual periods ending after September 15, 2009; therefore, we adopted this guidance as of July 1, 2009. Our adoption did not have any material impact on our financial position, results of operations or cash flows.

In May 2009, the FASB issued guidance that establishes general standards of accounting for and disclosure of subsequent events or events that occur after the balance sheet date but before financial statements are issued. This guidance sets forth (i) the period after the balance sheet date during which management shall evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements, (ii) the circumstances under which an entity shall recognize events or transactions occurring after the balance sheet date in its financial statements and (iii) the disclosures that an entity shall make about events or transactions that occurred after the balance sheet date. This guidance was effective for interim or annual periods ending after June 15, 2009; therefore, we adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB issued guidance that increases the frequency of fair value disclosures from annual to quarterly in an effort to provide financial statement users with more timely and transparent information about the effects of current market conditions on financial instruments. This is intended to address concerns raised by some financial statement users about the lack of comparability resulting from the use of different measurement attributes for financial instruments. These disclosures are also intended to stimulate more robust discussions about financial instrument valuations between users and reporting entities. We adopted this guidance as of April 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In November 2008, the FASB issued guidance that addresses certain accounting considerations, including initial measurement, decreases in investment value, and changes in the level of ownership or degree of influence related to equity method investments. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In April 2008, the FASB issued guidance that amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under previous guidance over goodwill and other intangible assets. The intent of this guidance is to improve the consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure the fair value of the asset under generally accepted accounting principles. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In March 2008, the FASB issued guidance that amends previous guidance with respect to disclosures of derivative instruments and hedging activities. This guidance requires enhanced disclosures about (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under the guidance and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The provisions of this guidance were effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted this guidance as of January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows. See Note 6 for enhanced disclosure of derivative instruments and hedging activities.

In March 2008, the FASB issued guidance that addresses the application of the two-class method in determining income per unit for master limited partnerships having multiple classes of securities that may participate in partnership distributions. The two-class method is an earnings allocation formula that determines earnings per unit for each class of common units and participating securities according to participation rights in undistributed earnings. We adopted this guidance as of January 1, 2009. This guidance has been applied retrospectively for all financial statement periods presented. Adoption impacted the net income available to limited partners used in our computation of earnings per unit, but did not impact our net income, distributions to limited partners, financial position, results of operations or cash flows.

In December 2007, the FASB issued guidance regarding accounting for noncontrolling interests in consolidated financial statements. This guidance requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The guidance eliminates the diversity that currently exists in accounting for transactions between an entity and noncontrolling interests by requiring that they be treated as equity transactions. The provisions of this guidance were effective on a prospective basis for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We adopted this guidance as of January 1, 2009. Such adoption did not have any material impact on our consolidated financial position, results of operations or cash flows.

In December 2007, the FASB issued further guidance regarding accounting for business combinations. This guidance establishes principles and requirements for how an acquirer (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. The provisions of this guidance were effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. We adopted this guidance as of January 1, 2009. Adoption has impacted our accounting for acquisitions subsequent to that date.

Derivative Instruments and Hedging Activities

We identify the risks that underlie our core business activities and utilize risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange-rate risk. We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value per the guidance issued by the FASB. This guidance requires that changes in the fair value of derivative instruments be recognized currently in earnings unless specific hedge accounting criteria are met, in which case, changes in fair value of cash flow hedges are deferred in AOCI and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in current period earnings for (i) derivatives that do not qualify for hedge accounting and (ii) the portion of cash flow hedges that are not highly effective in offsetting changes in cash flows of hedged items. See Note 6 for further discussion.

Net Income Per Limited Partner Unit

Basic and diluted net income per unit is determined by dividing our limited partners' interest in net income by the weighted average number of limited partner units outstanding during the period. Pursuant to guidance issued by the FASB on the application of the two-class method for master limited partnerships ("MLPs"), the limited partners' interest in net income attributable to Plains is calculated by first reducing net income by the distribution pertaining to the current period's net income, which is to be paid in the subsequent quarter (including the incentive distribution interest in excess of the 2% general partner interest). Then, the remaining undistributed earnings or excess distributions over earnings, if any, are allocated to the general partner and limited partners in accordance with the contractual terms of the partnership agreement. The adoption of this guidance resulted in a change to our calculation of earnings per unit by using distributions applicable to the period rather than distributions paid in the period (applicable to the previous period). Also, in accordance with this guidance, earnings per unit for prior periods were recast to conform to this revised calculation.

The following table sets forth the computation of basic and diluted earnings per limited partner unit for the years ended 2009, 2008, and 2007:

	Year Ended December 31,		
	2009	2008	2007
Numerator for basic and diluted earnings per limited partner unit:			
Net income attributable to Plains	$ 579	$ 437	$ 365
Less: General partner's incentive distribution paid [(1)]	(127)	(106)	(73)
Subtotal	452	331	292
Less: General partner 2% ownership [(1)]	(9)	(6)	(6)
Net income available to limited partners	443	325	286
Adjustment in accordance with application of the two-class method for MLPs [(1)]	(9)	(5)	(8)
Net income available to limited partners in accordance with the application of the two-class method for MLPs	$ 434	$ 320	$ 278
Denominator:			
Basic weighted average number of limited partner units outstanding	130	120	113
Effect of dilutive securities:			
Weighted average LTIP units [(2)]	1	1	1
Diluted weighted average number of limited partner units outstanding	131	121	114
Basic net income per limited partner unit	$ 3.34	$ 2.66	$ 2.47
Diluted net income per limited partner unit	$ 3.32	$ 2.64	$ 2.45

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

(2) Our LTIP awards (described in Note 10) that contemplate the issuance of common units are considered dilutive unless (i) vesting occurs only upon the satisfaction of a performance condition and (ii) that performance condition has yet to be satisfied. LTIP awards that are deemed to be dilutive are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in guidance issued by the FASB.

Note 3—Acquisitions and Dispositions

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

2009 Acquisitions

PNGS Acquisition. On September 3, 2009, we acquired the remaining 50% indirect interest in PAA Natural Gas Storage, LLC ("PNGS") for an aggregate purchase price of $215 million ("PNGS Acquisition"). The $215 million purchase price consisted of $90 million in cash paid at closing, approximately $91 million in equivalent value of PAA common units (1,907,305 PAA common units based on a 20 business-day average closing price per unit) issued to Vulcan at closing, and up to $40 million of deferred/contingent cash consideration. The deferred/contingent consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of this contingent consideration is approximately $34 million. As a result of the transaction, we now own 100% of PNGS's natural gas storage business and related operating entities, which are accounted for on a consolidated basis beginning in September 2009. We historically accounted for our 50% indirect interest in PNGS under the equity method. We recorded a net gain of approximately $9 million, recorded in other income, in connection with (i) adjusting our previously owned 50% investment in PNGS to fair value and (ii) terminating an agreement to supply natural gas to PNGS.

PNGS currently owns and operates two natural gas storage facilities located in Louisiana and Michigan that have an aggregate working gas storage capacity of 40 billion cubic feet ("Bcf") and an aggregate peak injection and withdrawal capacity of 1.7 Bcf per day and 3.2 Bcf per day, respectively. PNGS also leases storage capacity and pipeline transportation capacity from third parties from time to time in order to increase its operational flexibility and enhance the services it offers its customers. As of December 31, 2009, PNGS had 3 Bcf of storage capacity under lease from third parties and had secured the right to 379 MMcf per day of firm transportation service on various pipelines. Substantially all of PNGS's revenues are derived from the provision of firm storage services under multi-year, fee-based contracts. The gas storage operations are reflected in our facilities segment.

The purchase price consisted of the following (in millions):

Cash	$	90
PAA equity		91
Paid at closing		181
Fair value of contingent consideration [(1)]		34
Total purchase price	$	215

(1) The deferred contingent cash consideration is payable in cash in two installments of $20 million each upon the achievement of certain performance milestones and events expected to occur over the next several years. The fair value of the deferred contingent cash consideration was based on a discounted cash flow model utilizing a discount rate of approximately 9%.

The allocation of fair value to the assets and liabilities acquired in the PNGS Acquisition is as follows (in millions):

Property, plant and equipment	$	791
Base gas		28
Goodwill		25
Intangible assets		23
Working capital and other long-term assets and liabilities		9
Debt		(446)
Total	$	430

Other 2009 Acquisitions. During 2009, we completed six additional acquisitions for an aggregate consideration of approximately $178 million. These acquisitions included an additional 21% undivided joint interest in Capline and associated tankage, as well as various crude oil pipelines and pipeline systems that are all included within our transportation segment. We also acquired a natural gas processing business, a refined products terminal and various crude oil storage tanks and other related assets that are all included within our facilities segment. The goodwill associated with such acquisitions was approximately $24 million. As of December 31, 2009, purchase price allocations have not been finalized for all acquisitions.

2008 Acquisitions

Rainbow. In May 2008, we completed the acquisition of Rainbow Pipe Line Company, Ltd. ("Rainbow") for approximately $687 million (the Canadian dollar ("CAD") to U.S. dollar ("USD") foreign exchange rate at the date of closing was $0.993:1). The assets acquired include approximately (i) 480 miles of mainline crude oil pipelines, (ii) 119 miles of gathering pipelines, (iii) 570,000 barrels of tankage along the system and (iv) 1 million barrels of crude oil linefill. The system has a throughput capacity of approximately 200,000 barrels per day. The acquired operations are reflected primarily in our transportation segment. The goodwill associated with this acquisition was approximately $194 million. In anticipation of closing the Rainbow acquisition, we entered into forward currency exchange contracts, which exchanged Canadian dollars and U.S. 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. We recognized a gain on those positions of approximately $8 million and $3 million, respectively, which is reflected in our consolidated results of operations in the "Interest income and other income (expense), net" line.

The purchase price consisted of the following (in millions):

Cash payment to sellers	$ 659
Assumption of Rainbow debt (at estimated fair value)	26
Estimated transaction costs	2
Total purchase price	$ 687

The purchase price allocation is as follows (in millions):

Property, plant and equipment	$ 425
Pipeline linefill in owned assets	143
Intangible assets	52
Goodwill	191
Future income tax liability	(110)
Assumption of working capital and other long-term assets and liabilities, including cash [1]	(14)
Total	$ 687

(1) Includes approximately $16 million associated with environmental liabilities.

During 2008, we completed one additional acquisition for aggregate consideration of approximately $44 million. This acquisition is reflected in our facilities segment and included the purchase of a storage facility and other assets. There was no goodwill associated with this acquisition.

2007 Acquisitions

During 2007, we completed four acquisitions for aggregate consideration of approximately $123 million. These acquisitions included (i) a commercial refined products supply and marketing business (reflected in our supply and logistics segment) for approximately $8 million in cash, (ii) a trucking business (reflected in our transportation segment) for approximately $9 million in cash, (iii) the Bumstead LPG storage facility located near Phoenix, Arizona (reflected in our facilities segment) for approximately $52 million in cash and (iv) the Tirzah LPG storage facility and other assets located near York County, South Carolina (reflected in our facilities segment) for approximately $54 million in cash. The goodwill associated with these acquisitions was approximately $12 million.

Dispositions

During 2009, 2008 and 2007, we sold various property and equipment for proceeds totaling approximately $4 million, $12 million and $13 million, respectively. A loss of less than $1 million, a gain of approximately $6 million and a loss of $7 million were recognized in 2009, 2008 and 2007, respectively, related to these sales.

Note 4—Debt

Debt consists of the following (in millions):

	December 31, 2009	December 31, 2008
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.5% and 2.3% at December 31, 2009 and 2008, respectively	$ 300	$ 280
Senior unsecured revolving credit facility, bearing interest at a rate of 0.8% and 1.1% at December 31, 2009 and 2008, respectively [(1)]	772	746
Other	2	1
Total short-term debt	1,074	1,027
Long-term debt:		
4.75% senior notes due August 2009 [(2)]	—	175
4.25% senior notes due September 2012 [(3)]	500	—
7.75% senior notes due October 2012	200	200
5.63% senior notes due December 2013	250	250
7.13 % senior notes due June 2014 [(4)]	—	250
5.25% senior notes due June 2015	150	150
6.25% senior notes due September 2015	175	175
5.88% senior notes due August 2016	175	175
6.13% senior notes due January 2017	400	400
6.50% senior notes due May 2018	600	600
8.75% senior notes due May 2019	350	—
5.75% senior notes due January 2020	500	—
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized premium/(discount), net	(14)	(6)
Long-term debt under credit facilities and other [(1)]	6	40
Total long-term debt [(1)] [(5)]	4,142	3,259
Total debt	$ 5,216	$ 4,286

(1) At December 31, 2009 and 2008, we have classified $772 million and $746 million, respectively, of borrowings under our senior unsecured revolving credit facility as short-term. These borrowings are designated as working capital borrowings, must be repaid within one year, and are primarily for hedged LPG and crude oil inventory and New York Mercantile Exchange ("NYMEX") and IntercontinentalExchange ("ICE") margin deposits.

(2) We repaid our $175 million 4.75% senior notes on August 15, 2009.

(3) These notes were issued in July 2009 and the proceeds are being used to supplement capital available from our hedged inventory facility. At December 31, 2009, approximately $222 million had been used to fund hedged inventory and would be classified as short-term debt if funded on our credit facilities.

(4) On October 5, 2009 we redeemed all of our outstanding $250 million 7.13% senior notes due 2014. In conjunction with the early redemption, we recognized a loss of approximately $4 million.

(5) Our fixed rate senior notes have a face value of approximately $4.2 billion as of December 31, 2009. We estimate the aggregate fair value of these notes as of December 31, 2009 to be approximately $4.4 billion. Our fixed-rate senior notes are traded among institutions, which trades are routinely published by a reporting service. Our determination of fair value is based on reported trading activity near year end.

Credit Facilities

In October 2009, we renewed our 364-day committed hedged inventory credit facility, which matures in October 2010. The new committed facility replaced a similar $525 million facility that was scheduled to mature on November 5, 2009. The new facility has a borrowing capacity of $500 million, which may be increased to $1.2 billion subject to obtaining additional lender commitments. Borrowings under this facility will be used to finance the purchase of hedged crude oil inventory for storage activities and foreign imports. At December 31, 2009, borrowings of approximately $300 million were outstanding under this facility. At December 31, 2008, borrowings of approximately $280 million were outstanding under our previous $525 million committed hedged inventory facility.

As of both December 31, 2009 and 2008, the aggregate borrowing capacity of our senior unsecured revolving credit facility was $1.6 billion (including the sub-facility for Canadian borrowings of $600 million). This credit facility has a maximum debt coverage ratio of 4.75 to 1.0 (5.5 to 1.0 during an acquisition period) and a maturity date of July 2012. Also, the senior unsecured revolving credit facility can be expanded to $2.0 billion, subject to additional lender commitments. At December 31, 2009 and 2008, amounts outstanding under this facility and together with committed letters of credit were $849 million and $836 million, respectively.

Senior Notes

In September 2009, we completed the issuance of $500 million of 5.75% senior notes due January 15, 2020. The senior notes were sold at 99.523% of face value. Interest payments are due on January 15 and July 15 of each year, beginning on January 15, 2010. We used the net proceeds from this offering to repay outstanding borrowings under our credit facilities, a portion of which was used to fund the cash requirements of the PNGS Acquisition (which included repayment of all of PNGS's debt). See Note 3 for further discussion of the PNGS Acquisition.

In July 2009, we completed the issuance of $500 million of 4.25% senior notes due September 1, 2012. The senior notes were sold at 99.802% of face value. Interest payments are due on March 1 and September 1 of each year, beginning on March 1, 2010. We used the net proceeds from this offering to supplement the capital available under our existing hedged inventory facility to fund working capital needs associated with base levels of routine foreign crude oil import and for seasonal LPG inventory requirements. Concurrent with the issuance of these senior notes, we entered into interest rate swaps whereby we receive fixed payments at 4.25% and pay three-month LIBOR plus a spread on a notional principal amount of $150 million maturing in two years and an additional $150 million notional principal amount maturing in three years.

In April 2009, we completed the issuance of $350 million of 8.75% senior notes due May 1, 2019. The senior notes were sold at 99.994% of face value. Interest payments are due on May 1 and November 1 of each year, beginning on November 1, 2009. We used the net proceeds from this offering to reduce outstanding borrowings under our credit facilities.

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. In November 2008, the outstanding senior notes were exchanged for similar notes registered under the Securities Act.

In each instance, the notes were co-issued by Plains All American Pipeline, L.P. and a 100% owned consolidated finance subsidiary (neither of which have independent assets or operations) and are fully and unconditionally guaranteed, jointly and severally, by most of our subsidiaries. See Note 13 for information regarding our guarantor and non-guarantor subsidiaries.

Covenants and Compliance

Our credit agreements and the indentures governing the senior notes contain cross-default provisions. Our credit agreements prohibit distributions on, or purchases or redemptions of, units if any default or event of default is continuing. In addition, the agreements contain various covenants limiting our ability to, among other things:

- incur indebtedness if certain financial ratios are not maintained;
- grant liens;
- engage in transactions with affiliates;
- enter into sale-leaseback transactions; and
- sell substantially all of our assets or enter into a merger or consolidation.

Our senior unsecured revolving credit facility treats a change of control as an event of default and also requires us to maintain a debt-to-EBITDA coverage ratio that will not be greater than 4.75 to 1.0 on outstanding debt, and 5.5 to 1.0 on all outstanding debt during an acquisition period (generally, the period consisting of three fiscal quarters following an acquisition greater than $50 million).

For covenant compliance purposes, letters of credit and borrowings to fund hedged inventory and margin requirements are excluded when calculating the debt coverage ratio.

A default under our credit facility would permit the lenders to accelerate the maturity of the outstanding debt. As long as we are in compliance with our credit agreements, our ability to make distributions of available cash is not restricted. As of December 31, 2009, we were in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

In connection with our crude oil supply and logistics activities, we provide certain suppliers with irrevocable standby letters of credit to secure our obligation for the purchase of crude oil. 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 December 31, 2009 and 2008, we had outstanding letters of credit of approximately $76 million and $51 million, respectively.

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2009 was approximately 11 years and the aggregate maturities for the next five years and thereafter are as follows (in millions):

Calendar Year	Payment
2010	$ —
2011	—
2012	700
2013	250
2014	—
Thereafter	3,200
Total [1]	$ 4,150

[1] Excludes aggregate unamortized net discount of $14 million and an adjustment of $1 million related to a fair value hedge.

Note 5—Partners' Capital and Distributions

Units Outstanding

Partners' capital at December 31, 2009 consists of 136,135,988 common units outstanding, representing a 98% effective aggregate ownership interest in the Partnership and its subsidiaries after giving effect to the 2% general partner interest.

Distributions

We distribute 100% of our available cash within 45 days after the end of each quarter to unitholders of record and to our general partner. Available cash is generally defined as all of our cash and cash equivalents on hand at the end of each quarter, less reserves established by our general partner for future requirements.

General Partner Incentive Distributions

Our general partner is entitled to receive incentive distributions if the amount we distribute with respect to any quarter exceeds levels specified in our partnership agreement. Under the quarterly incentive distribution provisions, the general partner is typically entitled, without duplication, to 15% of amounts we distribute in excess of $0.450 per unit, referred to as our minimum quarterly distributions ("MQD"), 25% of the amounts we distribute in excess of $0.495 per unit and 50% of amounts we distribute in excess of $0.675 per unit (referred to as "incentive distributions").

Per unit cash distributions on our outstanding units and the portion of the distributions representing an excess over the MQD were as follows:

	Year					
	2009		2008		2007	
	Distribution (1)	Excess over MQD	Distribution (1)	Excess over MQD	Distribution (1)	Excess over MQD
First Quarter	$ 0.8925	$ 0.4425	$ 0.8500	$ 0.4000	$ 0.8000	$ 0.3500
Second Quarter	$ 0.9050	$ 0.4550	$ 0.8650	$ 0.4150	$ 0.8125	$ 0.3625
Third Quarter	$ 0.9050	$ 0.4550	$ 0.8875	$ 0.4375	$ 0.8300	$ 0.3800
Fourth Quarter	$ 0.9200	$ 0.4700	$ 0.8925	$ 0.4425	$ 0.8400	$ 0.3900

(1) Distributions represent those declared and paid in the applicable period.

In order to enhance our distribution coverage ratio and liquidity following a significant acquisition, our general partner may agree to reduce the amounts due to it as incentive distributions. Upon closing of the Pacific acquisition in November 2006 and the Rainbow acquisition in May 2008, our general partner agreed to reduce the amounts due to it as incentive distributions. Additionally, in connection with the PNGS Acquisition, our general partner agreed to further reduce its incentive distributions by an aggregate of $8 million over the next two years—$1.25 million per quarter for the first four quarters and $0.75 million per quarter for the next four quarters. This incentive distribution reduction became effective upon payment of our November 2009 quarterly distribution of $0.9200 per limited partner unit. The total reduction in incentive distributions related to the Pacific, Rainbow and PNGS acquisitions is $83 million as displayed on an annual basis in the following table (in millions):

Acquisition	2007	2008	2009	2010	2011	Total
Pacific	$ 20	$ 15	$ 15	$ 10	$ 5	$ 65
Rainbow	—	3	6	1	—	10
PNGS	—	—	1	5	2	8
Total	$ 20	$ 18	$ 22	$ 16	$ 7	$ 83

Following the distribution in February 2010 (as discussed below), the aggregate remaining incentive distribution reductions will be approximately $18 million.

Total cash distributions made were as follows (in millions, except per unit amounts):

	Distributions Paid				Distributions per limited partner unit
	Common	General Partner			
Year	Units	Incentive	2%	Total	
2009	$ 468	$ 127	$ 10	$ 605	$ 3.62
2008	$ 418	$ 106	$ 8	$ 532	$ 3.50
2007	$ 370	$ 73	$ 8	$ 451	$ 3.28

On January 20, 2010, we declared a cash distribution of $0.9275 per unit on our outstanding common units. The distribution was paid on February 12, 2010 to unitholders of record on February 2, 2010, for the period October 1, 2009 through December 31, 2009. The total distribution paid was approximately $166 million, with approximately $126 million paid to our common unitholders and $3 million and $37 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Noncontrolling Interest in a Subsidiary

During the fourth quarter of 2008, we completed construction on a 94-mile expansion of the Salt Lake City Area system from Wahsatch, Utah to Salt Lake City. During the first quarter of 2009, this pipeline became fully operational. Pursuant to a master formation agreement, we contributed the pipeline with a book value of approximately $254 million to a newly formed joint venture, SLC Pipeline LLC ("SLC Pipeline"). Holly Energy Partners-Operating, L.P. ("HEP") contributed approximately $26 million in cash for a 25% ownership in SLC Pipeline. We own the remaining 75% interest in SLC Pipeline and control the joint venture, and therefore, have consolidated the financial results. We recognized a loss in partners' capital of approximately $38 million related to the formation of the SLC Pipeline joint venture during 2009. This loss represents the difference between HEP's contribution of cash and the book value of its 25% interest in the net assets of SLC Pipeline. As of December 31, 2009, the noncontrolling interest on the balance sheet consists solely of HEP's interest in the net assets of SLC Pipeline.

Equity Offerings

During the three years ended December 31, 2009, we completed the following equity offerings of our common units (in millions, except unit and per unit data):

Period	Units Issued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds
September 2009 [1]	5,290,000	$ 46.70	$ 247	$ 5	$ (6)	$ 246
March 2009 [1]	5,750,000	36.90	212	4	(6)	210
2009 Total	**11,040,000**		**$ 459**	**$ 9**	**$ (12)**	**$ 456**
May 2008 [1]	6,900,000	$ 46.31	$ 320	$ 6	$ (11)	$ 315
2008 Total	**6,900,000**		**$ 320**	**$ 6**	**$ (11)**	**$ 315**
June 2007 [2]	6,296,172	$ 59.56	$ 375	$ 8	$ —	$ 383
2007 Total	**6,296,172**		**$ 375**	**$ 8**	**$ —**	**$ 383**

(1) These offerings of common units were underwritten transactions that required us to pay a gross spread. The net proceeds from these offerings were used to reduce outstanding borrowings under our credit facilities and for general partnership purposes.

(2) This offering was a direct placement of common units, did not involve underwriters and did not require a gross spread. However, the gross unit price includes the discount to market required to execute this transaction. The net proceeds of this offering were used (i) to fund expansion capital programs; (ii) to fund the acquisition of the Bumstead LPG storage business, which we acquired in 2007 for approximately $52 million; (iii) to repay indebtedness under our senior unsecured credit facility; and (iv) for general partnership purposes.

PNGS Acquisition

In September 2009, we issued 1,907,305 common units valued at approximately $91 million in order to satisfy a portion of the PNGS Acquisition purchase price. In conjunction with the issuance, we received a contribution from our general partner of approximately $2 million. See Note 3 for further discussion.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the board of directors of Plains All American GP LLC to issue grants of Class B units of Plains AAP, L.P. ("Class B units"). At December 31, 2009, grants of approximately 165,500 Class B units were outstanding, of which 38,500 were earned. A total of 34,500 Class B units are reserved for future issuances. See Note 10 for further discussion of Class B units.

Canadian Withholding Tax

For federal income tax purposes, we are treated as a partnership. Our unitholders are required to report their share of our income, gains, losses and deductions on their federal income tax return. In certain cases, we are subject to, and have paid, Canadian income and withholding taxes. The withholding tax payments are considered to be paid on behalf of our unitholders and thus are treated as distributions for financial reporting purposes. During 2009, we paid approximately $6 million of Canadian withholding taxes.

Note 6—Derivatives and Hedging Instruments

We identify the risks that underlie our core business activities and utilize risk management strategies to mitigate those risks when we determine that there is value in doing so. We use various derivative instruments to (i) manage our exposure to commodity price risk as well as to optimize our profits, (ii) manage our exposure to interest rate risk and (iii) manage our exposure to currency exchange-rate risk. Our policy is to use derivative instruments only for risk management purposes. Our commodity risk management policies and procedures are designed to monitor NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations, delivery schedules and storage capacity to help ensure that our hedging activities address our risks. Our interest rate and foreign currency risk management policies and procedures are designed to monitor our positions and ensure that those positions are consistent with our objectives and approved strategies. Our policy is to formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives and strategies for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged transaction, the nature of the risk being hedged and how the hedging instrument's effectiveness will be assessed. Both at the inception of the hedge and on an ongoing basis, we assess whether the derivatives used in a transaction are highly effective in offsetting changes in cash flows or the fair value of hedged items. A discussion of our derivative activities by risk category follows.

Commodity Price Risk Hedging

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

The material commodity related risks inherent in our business activities can be summarized into the following general categories:

Commodity Purchases and Sales — In the normal course of our supply and logistics operations, we purchase and sell crude oil, LPG, and refined products. We use derivatives to manage the associated risks and to optimize profits. As of December 31, 2009, material net derivative positions related to these activities included:

- An approximate 173,900 barrel per day net long position (total of 5.2 million barrels) associated with our crude oil activities, which was unwound ratably during January 2010 to match monthly average pricing.

- An approximate 17,500 barrel per day (total of 13.1 million barrels) net short spread position which hedge a portion of our anticipated crude oil lease gathering purchases through January 2012. These derivatives protect our margin on future floating price crude oil purchase commitments. These derivatives in the aggregate do not result in exposure to outright price movements.

- A net short spread position averaging approximately 8,300 barrels per day (total of 6 million barrels) of calendar spread call options for the period February 2010 through January 2012. These derivatives in the aggregate do not result in exposure to outright price movements.

- An average of approximately 4,200 barrels per day (total of 1.1 million barrels) of butane/West Texas Intermediate ("WTI") spread positions, which hedge specific butane sales contracts that are priced as a fixed percentage of WTI and

  continue through September 2010.

- Approximately 18,500 barrels per day on average (total of 6.7 million barrels) of crude oil basis differential hedges through December 2010.

- An approximate 5,600 barrels per day (total of 0.5 million barrels) of propane swaps to hedge committed sales of propane inventory through March 2010.

Storage Capacity Utilization — We own approximately 57 million barrels of crude oil, LPG and refined products storage capacity that is not used in our transportation operations. This storage may be leased to third parties or utilized in our own supply and logistics activities, including for the storage of inventory in a contango market. For capacity allocated to our supply and logistics operations we have utilization risk if the market structure is backwardated. As of December 31, 2009, we used derivatives to manage the risk of not utilizing approximately 3 million barrels per month of storage capacity through 2011. These positions are a combination of calendar spread options and NYMEX futures contracts. These positions involve no outright price exposure, but instead represent potential offsetting purchases and sales between time periods (first month versus second month for example).

Inventory Storage — At times, we elect to purchase and store crude oil, LPG and refined products inventory in conjunction with our supply and logistics activities. These activities primarily relate to the seasonal storage of LPG inventories and contango market storage activities. When we purchase and store barrels, we enter into physical sales contracts or use derivatives to mitigate price risk associated with the inventory. As of December 31, 2009, we had approximately 8.2 million barrels of inventory hedged with derivatives.

We also purchase foreign cargoes of crude oil and may enter into derivatives to mitigate various price risks associated with the purchase and ultimate sale of foreign crude inventory. As of December 31, 2009, we had approximately 2.6 million barrels of crude oil derivatives hedging the anticipated sale of foreign crude inventory and 2.2 million barrels of crude oil spread positions hedging the anticipated purchase of foreign crude inventory.

Pipeline Loss Allowance Oil — As is common in the pipeline transportation industry, our tariffs incorporate a loss allowance factor that is intended to, among other things, offset losses due to evaporation, measurement and other losses in transit. We utilize derivative instruments to hedge a portion of the anticipated sales of the allowance oil that is to be collected under our tariffs. As of December 31, 2009, we had entered into a net short position consisting of crude oil futures and swaps to manage the risk associated with the anticipated sale of an average of approximately 2,300 barrels per day (total of 2.4 million barrels) from January 2010 through December 2012. In addition, we had a long put option position of approximately 1 million barrels through December 2012 and a net long call option position of approximately 2 million barrels through December 2011, which provide upside price participation.

Diluent Purchases — We use diluent in our Canadian crude oil pipeline operations and have used derivative instruments to hedge the anticipated forward purchases of diluent and diluent inventory. As of December 31, 2009, we had an average of 2,400 barrels per day of natural gasoline/WTI spread positions (approximately 1.3 million barrels) that run through mid-2011 and an average of 3,300 barrels per day of short crude oil futures (approximately 0.6 million barrels) to hedge condensate through the second quarter of 2010.

Natural Gas Purchases — Our gas storage facilities require minimum levels of natural gas ("base gas") to operate. For our natural gas storage facilities that are under construction, we anticipate purchasing base gas in future periods as construction is completed. We use derivatives to hedge anticipated purchases of natural gas. As of December 31, 2009, we have a net long position of approximately 3 Bcf consisting of natural gas futures contracts through August 2010.

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

Interest Rate Risk Hedging

We use interest rate derivatives to hedge interest rate risk associated with anticipated debt issuances and in certain cases, outstanding debt instruments. The derivative instruments we use to manage this risk consist primarily of interest rate swaps and treasury locks. As of December 31, 2009, AOCI includes deferred losses of $8 million that relate to terminated interest rate swaps and treasury locks that were designated for hedge accounting. These terminated interest rate derivatives were cash settled in connection with the issuance and refinancing of debt agreements. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the forecasted debt instruments.

As of December 31, 2009, we had four outstanding interest rate swaps by which we receive fixed interest payments and pay floating-rate interest payments based on three-month LIBOR plus an average spread of 2.42% on a semi-annual basis. The swaps have an aggregate notional amount of $300 million with fixed rates of 4.25%. Two of the swaps terminate in 2011 and two of the swaps terminate in 2012.

Currency Exchange Rate Risk Hedging

We use foreign currency derivatives to hedge foreign currency risk associated with our exposure to fluctuations in the USD-to-CAD exchange rate. Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments primarily include forward exchange contracts and foreign currency forwards and options. As of December 31, 2009, AOCI includes net deferred gains of $15 million that relate to open and settled forward exchange contracts that were designated for hedge accounting. These forward exchange contracts hedge the cash flow variability associated with CAD-denominated interest payments on a CAD-denominated intercompany note as a result of changes in the foreign exchange rate.

As of December 31, 2009, our outstanding foreign currency derivatives also include derivatives used to hedge CAD-denominated crude oil purchases and sales. We may from time to time hedge the commodity price risk associated with a CAD-denominated commodity transaction with a USD-denominated commodity derivative. In conjunction with entering into the commodity derivative we enter into a foreign currency derivative to hedge the resulting foreign currency risk. These foreign currency derivatives are generally short-term in nature and are not designated for hedge accounting.

At December 31, 2009, our open foreign exchange derivatives included forward exchange contracts that exchange CAD for USD on a net basis as follows (in millions):

	CAD	USD	Average Exchange Rate
2010	$ 43	$ 39	CAD $1.14 to USD $1.00
2011	$ 15	$ 15	CAD $1.01 to USD $1.00
2012	$ 15	$ 15	CAD $1.01 to USD $1.00
2013	$ 9	$ 9	CAD $1.00 to USD $1.00

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

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. All of our commodity derivatives that qualify for hedge accounting are designated as cash flow hedges. Therefore, the corresponding changes in fair value for the effective portion of the hedges are deferred to AOCI and recognized in earnings in the periods during which the underlying physical transactions impact earnings. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective in offsetting changes in cash flows of the hedged items, are recognized in earnings each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

A summary of the impact of our derivative activities recognized in earnings for the twelve months ended December 31, 2009 is as follows (in millions, losses designated in parentheses):

Year Ended December 31, 2009

		Derivatives in Cash Flow Hedging Relationships			
	Location of gain/(loss)	**AOCI Reclass (1)**	**Ineffective Portion (2)**	**Derivatives Not Designated as a Hedge (3)**	**Total**
Commodity contracts.......	Supply and Logistics segment revenues	$ (90)	$ (8)	$ (10)	$ (108)
	Transportation segment revenues	4	—	—	4
	Facilities segment revenues	(1)	—	—	(1)
	Purchases and related costs	69	—	122	191
Interest Rate Contracts.....	Other income, net	—	—	(1)	(1)
	Interest expense	(1)	—	3	2
Foreign Exchange Contracts.....................	Supply and Logistics segment revenues	—	—	7	7
	Purchases and related costs	1	—	3	4
	Other income, net	10	—	(7)	3
Total Gain/(Loss) on Derivatives Recognized in Income		**$ (8)**	**$ (8)**	**$ 117**	**$ 101**

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

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

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

The following table summarizes the derivative assets and liabilities on our consolidated balance sheet as of December 31, 2009 (in millions):

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as hedging instruments:				
Commodity contracts	Other current assets	$ 153	Other current liabilities	$ (140)
	Other long-term assets	34	Other long-term liabilities	(1)
Interest rate contracts	Other current assets	—	Other current liabilities	—
	Other long-term assets	—	Other long-term liabilities	—
Foreign exchange contracts	Other current assets	—	Other current liabilities	—
	Other long-term assets	2	Other long-term liabilities	—
Total derivatives designated as hedging instruments		$ 189		$ (141)
Derivatives not designated as hedging instruments:				
Commodity contracts	Other current assets	$ 34	Other current liabilities	$ (91)
	Other long-term assets	41	Other long-term liabilities	(34)
Interest rate contracts	Other current assets	1	Other current liabilities	—
	Other long-term assets	1	Other long-term liabilities	—
Foreign exchange contracts	Other current assets	2	Other current liabilities	(3)
	Other long-term assets	—	Other long-term liabilities	—
Total derivatives not designated as hedging instruments		$ 79		$ (128)
Total derivatives		$ 268		$ (269)

As of December 31, 2009, there was a net gain of $18 million deferred in AOCI. The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the earnings recognition of the underlying hedged physical transaction, (ii) interest expense accruals associated with underlying debt instruments or (iii) the recognition of a foreign currency gain or loss upon the remeasurement of certain CAD-denominated intercompany interest receivables. Of the total net gain deferred in AOCI at December 31, 2009, a net loss of approximately $25 million is expected to be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 96% is expected to be reclassified to earnings prior to 2013 with the remaining deferred gain being reclassified to earnings through 2019. These amounts are predominately based on market prices at the current period end, thus actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2009, we reclassed a deferred gain of approximately $5 million from AOCI to other income as a result of anticipated hedge transactions that are no longer considered to be probable of occurring. During the year ended December 31, 2008, no amounts were reclassed from AOCI as a result of anticipated hedge transactions that were no longer considered to be probable of occurring.

Amounts of loss recognized in AOCI on derivatives (effective portion) during the year ended December 31, 2009 are as follows (in millions):

	For the Year Ended December 31, 2009
Commodity contracts	$ (145)
Foreign exchange contracts	(4)
Interest rate contracts	(2)
Total	$ (151)

We do not enter into master netting agreements with our over-the-counter derivative counterparties, nor do we 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. The account equity in our brokerage accounts is a combination of our cash balance and the fair value of our open derivatives within our brokerage account. When our account equity is less than our initial margin requirement we are required to post margin. Our broker receivable was approximately $53 million and $81 million as of December 31, 2009 and 2008, respectively. At December 31, 2009 and December 31, 2008, none of our outstanding derivatives contained credit-risk related contingent features that would result in a material adverse impact to us upon any change in our credit ratings.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment which does affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of December 31, 2009 (in millions)				Fair Value as of December 31, 2008 (in millions)			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Commodity derivatives	$ 251	$ —	$ 11	$ 262	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives	—	—	2	2	—	—	5	5
Foreign currency derivatives	—	—	4	4	—	—	18	18
Total assets at fair value	$ 251	$ —	$ 17	$ 268	$ 235	$ 9	$ 135	$ 379
Liabilities:								
Commodity derivatives	$ (224)	$ —	$ (42)	$ (266)	$ (330)	$ —	$ (56)	$ (386)
Foreign currency derivatives	—	—	(3)	(3)	—	—	(5)	(5)
Total liabilities at fair value	$ (224)	$ —	$ (45)	$ (269)	$ (330)	$ —	$ (61)	$ (391)
Net asset/(liability) at fair value	$ 27	$ —	$ (28)	$ (1)	$ (95)	$ 9	$ 74	$ (12)

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

Level 1

Included within level 1 of the fair value hierarchy are exchange-traded commodity derivatives such as futures, options and swaps. The fair value of exchange-traded commodity derivatives is based on unadjusted quoted prices in active markets and is therefore classified within level 1 of the fair value hierarchy.

Level 2

Included within level 2 of the fair value hierarchy as of December 31, 2008 is a physical commodity supply contract that meets the definition of a derivative but does not qualify for the NPNS scope exception as set forth in FASB guidance. 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 the following derivatives:

- Commodity Derivatives: Level 3 commodity derivatives include over-the-counter commodity derivatives such as forwards, swaps and options and certain physical commodity contracts. The fair value of our level 3 commodity derivatives is based on either an indicative broker or dealer price quotation or a valuation model. Our valuation models utilize inputs such as price, volatility and correlation and do not involve significant management judgments.

- Interest Rate Derivatives: Level 3 interest rate derivatives include interest rate swaps. The fair value of our interest rate derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward LIBOR curves and forward Treasury yields that are obtained from pricing services.

- Foreign Currency Derivatives: Level 3 foreign currency derivatives include foreign currency swaps, forward exchange contracts and options. The fair value of our foreign currency derivatives is based on indicative broker or dealer price quotations. Broker or dealer price quotations are corroborated with objective inputs including forward CAD/USD forward exchange rates that are obtained from pricing services.

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

Rollforward of Level 3 Net Liability

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

	Year Ended December 31, 2009	2008
Beginning Balance	$ 74	$ (21)
Unrealized gains/(losses):		
Included in earnings [1]	46	68
Included in other comprehensive income	(43)	35
Settlements and derivatives entered into during the period	(105)	(8)
Ending Balance	$ (28)	$ 74
Change in unrealized gains/(losses) included in earnings relating to level 3 derivatives still held at the end of the periods	$ 31	$ 44

(1) Unrealized gains and losses associated with level 3 commodity derivatives are reported in our consolidated statements of operations as supply and logistics segment revenues. Gains and losses associated with interest rate derivatives are reported in our consolidated statements of operations as either other income, net or interest expense. Gains and losses associated with foreign currency derivatives are reported in our consolidated statements of operations as either supply and logistics segment revenues, purchases and related costs, or other income, net.

We believe that a proper analysis of our level 3 gains or losses must incorporate the understanding that these items are generally used to hedge our commodity price risk, interest rate risk and foreign currency exchange risk and are therefore offset by the underlying transactions.

Note 7—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. Although, we are subject to state income taxes in some states, the impact to the years ended December 31, 2009, 2008 and 2007 was immaterial.

Canadian Federal and Provincial Taxes

Certain of our Canadian subsidiaries 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 has historically been treated as a flow-through entity for tax purposes. This entity is subject to Canadian legislation passed in June 2007 that imposes entity-level taxes on certain types of flow-through entities. This legislation includes safe harbor guidelines that grandfather certain existing entities (which, we believe, would include us) and delays the effective date of such legislation until 2011.

Additionally, in December 2008, the Fifth Protocol to the U.S./Canada Tax Treaty was ratified and contained language that increases the withholding tax on dividends and intercompany interest effective in 2010. As a result of these collective changes, we are in the process of reviewing our Canadian structure.

Tax Components

Components of income tax expense are as follows (in millions):

	Year Ended December 31,		
	2009	2008	2007
Current tax expense:			
State income tax	$ 2	$ 1	$ 1
Canadian federal and provincial income tax	13	8	2
Total current tax expense	$ 15	$ 9	$ 3
Deferred tax (benefit)/expense:			
State income tax	$ —	$ —	$ 1
Canadian federal and provincial income tax	(9)	(1)	12
Total deferred tax (benefit)/expense	$ (9)	$ (1)	$ 13
Total income tax expense	$ 6	$ 8	$ 16

The difference between tax expense based on the statutory federal income tax rate and our effective tax expense is summarized as follows (in millions):

	Year Ended December 31,		
	2009	2008	2007
Income before tax	$ 586	$ 445	$ 381
Partnership earnings not subject to current Canadian tax	(585)	(422)	(369)
	$ 1	$ 23	$ 12
Canadian federal and provincial corporate tax rate	29.0%	29.5%	32.1%
Income tax at statutory rate	$ —	$ 7	$ 4
Current tax expense:			
Canadian period tax as a result of book versus tax differences	4	4	(2)
Canadian permanent differences between book and tax	9	(3)	—
State income tax	2	1	1
Current income tax expense	$ 15	$ 9	$ 3
Deferred tax expense:			
State deferred income tax	—	—	1
Canadian deferred tax (benefit)/expense as a result of book versus tax differences	(4)	(4)	2
Canadian flow-through entities deferred tax (benefit)/expense as a result of book versus tax differences	(5)	3	10
Deferred income tax (benefit)/expense	$ (9)	$ (1)	$ 13
Total income tax expense	$ 6	$ 8	$ 16

Deferred tax assets and liabilities, which are included net within other long-term liabilities and deferred credits in our consolidated balance sheet, result from the following (in millions):

	December 31,	
	2009	2008
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 13	$ 9
Total deferred tax assets	13	9
Deferred tax liabilities:		
Property, plant and equipment in excess of tax values	(134)	(118)
Total deferred tax liabilities	(134)	(118)
Net deferred tax liabilities	$ (121)	$ (109)

Generally, tax returns for our Canadian entities are open to audit from 2005 through 2009. Our U.S. and state tax years are open to examination from 2006 to 2009.

Note 8—Major Customers and Concentration of Credit Risk

Marathon Petroleum Company, LLC accounted for 14%, 14% and 19% of our revenues for each of the three years ended December 31, 2009, 2008 and 2007, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12%, 12% and 11% of our revenues for the years ended December 31, 2009, 2008 and 2007, respectively. No other customers accounted for 10% or more of our revenues during any of the three years ended December 31, 2009. The majority of revenues from these customers pertain to our supply and logistics operations. We believe that the loss of these customers would have only a short-term impact on our operating results. There is risk, however, that we would not be able to identify and access a replacement market at comparable margins.

Financial instruments that potentially subject us to concentrations of credit risk consist principally of trade receivables. Our accounts receivable are primarily from purchasers and shippers of crude oil. This industry concentration has the potential to impact our overall exposure to credit risk in that the customers may be similarly affected by changes in economic, industry or other conditions. We review credit exposure and financial information of our counterparties and generally require letters of credit for receivables from customers that are not considered creditworthy, unless the credit risk can otherwise be reduced. See Note 2 for additional discussion of our accounts receivable and our review of credit exposure.

Note 9—Related Party Transactions

Reimbursement of Expenses of Our General Partner and its Affiliates

We do not pay our general partner a management fee, but we do reimburse our general partner for all direct and indirect costs of services provided to us or incurred on our behalf, including the costs of employee, officer and director compensation and benefits allocable to us as well as all other expenses necessary or appropriate to the conduct of our business (other than expenses related to grants of Class B units). We record these costs on the accrual basis in the period in which our general partner incurs them. Our partnership agreement provides that our general partner will determine the expenses that are allocable to us in any reasonable manner determined by our general partner in its sole discretion. Total costs reimbursed by us to our general partner for the years ended December 31, 2009, 2008 and 2007 were $328 million, $289 million and $287 million, respectively.

Vulcan Energy Corporation

As of December 31, 2009, Vulcan Energy Corporation ("Vulcan Energy") and its affiliates owned approximately 50% of our general partner interest, as well as approximately 9% of our outstanding limited partner units.

Voting Agreement. In August 2005, Vulcan Energy's ownership interest in our general partner increased from 44% to over 50%. At the closing of the transaction, Vulcan Energy entered into a voting agreement that restricts its ability to unilaterally elect or remove our independent directors, and separately, our CEO and COO agreed, subject to certain ongoing conditions, to waive certain change-of-control payment rights that would otherwise have been triggered by the increase in Vulcan Energy's ownership interest. These ownership changes to our general partner had no material impact on us.

Another owner of Plains All American GP LLC, Lynx Holdings I, LLC, agreed to restrict certain of its voting rights with respect to its approximate 1.4% membership interest in Plains All American GP LLC.

Administrative Services Agreement. On October 14, 2005, Plains All American GP LLC ("GP LLC") and Vulcan Energy entered into an Administrative Services Agreement, effective as of September 1, 2005 (the "Services Agreement"). Pursuant to the Services Agreement, GP LLC provides administrative services to Vulcan Energy for consideration of an annual fee, plus certain expenses. Effective October 1, 2006, the annual fee for providing these services was increased to $1 million. Beginning in October 2008, the Services Agreement automatically renews for successive one-year periods unless either party provides written notice of its intention to terminate the Services Agreement. Pursuant to the agreement, Vulcan Energy has appointed certain employees of GP LLC as officers of Vulcan Energy for administrative efficiency. Under the Services Agreement, Vulcan Energy acknowledges that conflicts may arise between itself and GP LLC. If GP LLC believes that a specific service is in conflict with the best interest of GP LLC or its affiliates then GP LLC is entitled to suspend the provision of that service and such a suspension will not constitute a breach of the Services Agreement.

Omnibus Agreement. PAA, GP LLC, certain affiliated entities and Vulcan Energy are parties to an amended and restated omnibus agreement dated as of July 23, 2004. Pursuant to this agreement, Vulcan Energy has agreed, so long as Vulcan Energy or any of its affiliates owns an interest, directly or indirectly, in GP LLC, not to engage in or acquire any business engaged in the following activities:

- crude oil storage, terminalling and gathering activities in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than entities affiliated with Vulcan Energy and its affiliates (collectively, the "Vulcan entities") or GP LLC, PAA, its operating partnerships and any controlled affiliates (collectively, the "Plains entities");

- crude oil marketing activities; and
- transportation of crude oil by pipeline in any state in the United States (except for Hawaii), the Outer Continental Shelf of the United States or any province or territory in Canada, for any person other than the Plains entities.

These restrictions are subject to specified permitted exceptions and may be terminated by Vulcan Energy upon certain change of control events involving Vulcan Energy. The omnibus agreement further permits, except as otherwise restricted by the omnibus agreement or any other agreement, each Vulcan entity to engage in any business activity, including those that may be in direct competition with the Plains entities. Further, any owner of equity interests in Vulcan Energy may make passive investments in PAA's competitors so long as such owner does not directly or indirectly use any knowledge or confidential information it received through the ownership by a Plains entity to compete, or to engage in or become interested financially in any person that competes, in the restricted activities described above.

Crude Oil Purchases. From August 2005 to May 2007, Calumet Florida L.L.C ("Calumet") was owned by Vulcan Resources Florida, Inc., the majority of which is owned by Paul G. Allen. In May 2007, Calumet was sold and ceased to be related to Vulcan Energy. In 2007, until the date that Calumet ceased to be related to Vulcan Energy, we purchased crude oil from Calumet for approximately $17 million.

Investment in PAA/Vulcan Gas Storage, LLC

In September 2005, we and Vulcan Gas Storage LLC, a subsidiary of Vulcan LLC, an investment arm of Paul G. Allen, formed PAA/Vulcan Gas Storage, LLC to acquire ECI (now known as PAA Natural Gas Storage, LLC or "PNGS"), an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage each made an initial cash investment of approximately $113 million and Bluewater Natural Gas Storage, LLC, a subsidiary of PAA/Vulcan, entered into a $90 million credit facility contemporaneously with closing.

From September 2005 until September 3, 2009, we owned 50% of PAA/Vulcan and Vulcan Gas Storage LLC owned the other 50%. Giving effect to all contributions and distributions made during the period from January 1, 2007 through September 3, 2009, we and Vulcan Gas Storage each made a net contribution of $39 million. Such contributions and distributions did not result in an increase or decrease to our ownership interest.

On September 3, 2009, one of our subsidiaries acquired the remaining 50% interest in PAA/Vulcan from Vulcan Gas Storage LLC, which resulted in our ownership of a 100% interest in PNGS. See Note 3 for further discussion of the PNGS Acquisition.

Note 10—Equity Compensation Plans

Our general partner has adopted the Plains All American GP LLC 1998 Long-Term Incentive Plan (the "1998 Plan"), the 2005 Long-Term Incentive Plan (the "2005 Plan") and the PPX Successor Long-Term Incentive Plan (the "PPX Successor Plan") for employees and directors as well as 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 1.6 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 is entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

In accordance with FASB guidance regarding share-based payments, 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 we amortize that expense over the service period.

When awards with performance conditions that were previously considered improbable of occurring become probable of occurring, we incur additional LTIP compensation expense necessary to adjust the life-to-date accrued liability associated with these awards. Our DER awards typically contain performance conditions based on the attainment of certain annualized distribution levels and become earned upon 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 December 31, 2009 , the following LTIP awards were outstanding (units in millions):

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date 2010	2011	2012	2013
0.6(1)	$3.20	0.6	—	—	—
1.5(2)	$3.50 - $4.50	—	0.5	0.8	0.1
1.8(3)	$3.50 - $4.25	0.5	0.3	0.8	0.2
3.9(4) (5)		1.1	0.8	1.6	0.3

(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 period.

(2) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.50 and vest upon the later of a certain date or the attainment of such levels. If the performance conditions are not attained while the grantee remains employed by us, or the grantee does not meet employment requirements, these awards will be forfeited. For purposes of this disclosure, the awards are presented above based on an estimate of future distribution levels and assuming that all grantees remain employed by us through the vesting date.

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

(4) Approximately 2.0 million of our approximately 3.9 million outstanding LTIP awards also include DERs, of which 1.0 million are currently earned.

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

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

	Year Ended December 31, 2009 Units	2009 Weighted Average Grant Date Fair Value per Unit	2008 Units	2008 Weighted Average Grant Date Fair Value per Unit	2007 Units	2007 Weighted Average Grant Date Fair Value per Unit
Outstanding at beginning of period....	3.9	$ 36.44	3.6	$ 37.75	3.0	$ 31.94
Granted	0.6	32.20	0.5	31.79	1.6	47.25
Vested	(0.6)	34.55	(0.1)	32.44	(0.7)	34.86
Cancelled or forfeited	(0.1)	37.82	(0.1)	36.14	(0.3)	36.00
Acquired [1]	0.1	26.24	—	—	—	—
Outstanding at end of period........................	3.9	$ 36.40	3.9	$ 36.44	3.6	$ 37.75

(1)As a result of the PNGS Acquisition, LTIP awards that were granted to PNGS employees in prior years are now included in our consolidated outstanding LTIP awards.

Our accrued liability at December 31, 2009 related to all outstanding LTIP awards and DERs is approximately $87 million, which includes an accrual associated with our assessment that an annualized distribution of $3.90 is probable of occurring. We have not deemed a distribution of more than $3.90 to be probable. At December 31, 2008, the accrued liability was approximately $55 million.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the issuance of up to 200,000 Class B units of Plains AAP, L.P. Class B units become earned in various 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 unit awards are entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million (as adjusted for debt service costs and excluding special distributions funded by debt) 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 (as adjusted) each quarter. The following table contains a summary of Class B unit awards that were (i) reserved for future grants, (ii) outstanding and (iii) earned for the years ended December 31, 2009 and 2008:

	Reserved for Future Grants	Outstanding	Outstanding Units Earned	Grant Date Fair Value Of Outstanding Class B Units (1) (in millions)
Balance as of December 31, 2008	46,000	154,000	21,000	$ 34
Class B unit issuance	(11,500)	11,500	—	2
Class B units earned	—	—	17,500	—
Balance as of December 31, 2009	34,500	165,500	38,500	$ 36

(1) Of the grant date fair value, approximately $5 million and $12 million was recognized as expense during the years ended December 31, 2009 and 2008, respectively.

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 thus, results in a corresponding credit to Partners' Capital in our Consolidated Financial Statements.

Other Consolidated Equity Compensation Information

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

	Year Ended December 31, 2009	2008	2007
Equity compensation expense	$ 68	$ 24	$ 49
LTIP unit vestings	$ 19	$ 1	$ 17
LTIP cash settled vestings	$ 8	$ 2	$ 16
DER cash payments	$ 4	$ 4	$ 4

Approximately 0.5 million and 0.3 million units were issued in 2009 and 2007, respectively, in connection with the settlement of vested awards. The remaining 0.1 million, 0.1 million and 0.4 million of awards that vested during 2009, 2008 and 2007, respectively, were settled in cash. Based on the December 31, 2009 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $52 million of additional expense over the life of our outstanding awards related to the remaining unrecognized fair value. This estimate is based on the closing market price of our units of $52.85 at December 31, 2009. Actual amounts may differ materially as a result of a change in the market price of our units and/or probability assessment regarding future distributions. We estimate that the remaining fair value will be recognized in expense as shown below (in millions):

Year	Equity Compensation Plan Fair Value Amortization (1) (2)
2010	$ 30
2011	14
2012	7
2013	1
2014	—
Total	$ 52

(1) Amounts do not include fair value associated with awards containing performance conditions that are not considered to be probable of occurring at December 31, 2009.

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

Note 11—Commitments and Contingencies

Commitments

We lease certain real property, equipment and operating facilities under various operating and capital leases. We also incur costs associated with leased land, rights-of-way, permits and regulatory fees, the contracts for which generally extend beyond one year but can be cancelled at any time should they not be required for operations. Future non-cancelable commitments related to these items at December 31, 2009, are summarized below (in millions):

2010	$ 79
2011	62
2012	54
2013	33
2014	23
Thereafter	240
Total	$ 491

Expenditures related to leases for 2009, 2008 and 2007 were $90 million, $82 million and $51 million, respectively.

Contingencies

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 U.S. 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 $5 million to $6 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. 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 DOJ and EPA. Our assessment is that it is probable we will pay penalties related to the releases. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We have accrued our current estimate of the likely penalties as a loss contingency, which is included in the estimated aggregate costs set forth above. We understand that the maximum permissible penalty, if any, that EPA could assess with respect to the subject releases under relevant statutes would be approximately $6.8 million. Such statutes contemplate the potential for substantial reduction in penalties based on mitigating circumstances and factors. We believe that several of such circumstances and factors exist, and thus have been a primary focus in our discussions with the DOJ and EPA with respect to these matters.

SemCrude L.P., et al — Debtors (U.S. Bankruptcy Court — Delaware). We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude, which commenced in July 2008. As a result of our statutory protections and contractual rights of setoff, substantially all of our pre-petition claims against SemCrude should be satisfied. Certain creditors of SemCrude and its affiliates have challenged our contractual and statutory rights to setoff certain of our payables to the debtor against our receivables from the debtor. The aggregate amount subject to challenge is approximately $23 million. Certain SemCrude creditors have also filed state court actions alleging a producer’s lien on crude oil sold to SemCrude, and the continuation of such lien when SemCrude sold the oil to subsequent purchasers such as us. These suits may be consolidated and heard in the U.S. Bankruptcy Court in Delaware. We intend to vigorously defend our contractual and statutory rights.

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

United States of America 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 the pipeline 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 September 2008, the EPA filed a civil complaint against PPS, a subsidiary acquired in the Pacific merger, in connection with the Pyramid Lake release. The complaint, which was filed in the Federal District Court for the Central District of California, Civil Action No. CV085768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately $3.7 million. In January 2010, the DOJ, EPA and PPS entered into a proposed consent decree, which will be published in the Federal Register and then be subject to a 30-day public comment period. If there are no objections prior to the end of the public comment period, the Court is expected to sign the consent decree. After the consent decree becomes effective, PPS will pay a civil penalty of $1.3 million and comply with other requirements set forth in the consent decree, which include performance of additional remediation and restoration tasks. Total projected costs associated with this additional work are estimated at less than $6 million. PPS is also prohibited from transferring ownership of Line 63 to an unaffiliated entity unless the transferee agrees in writing to be bound by any provisions of the consent decree that have not been previously satisfied. This prohibition on transfer will not apply if PPS retains a portion of ownership and continues as operator of the line.

ExxonMobil Corp. v. GATX Corp. (Superior Court of New Jersey — Gloucester County). This Pacific legacy matter was filed by ExxonMobil in April 2003 and involves the allocation of responsibility for remediation of MTBE and other petroleum product contamination at the Pacific Atlantic Terminals LLC (“PAT”) facility at Paulsboro, New Jersey. We estimate that the maximum potential cost to effectively remediate ranges up to $10 million although the New Jersey Department of Environmental Protection (“NJDEP”) is asserting a much larger expenditure. Both ExxonMobil and GATX were prior owners of the terminal. We contend that ExxonMobil and GATX are primarily responsible for the majority of the remediation costs. We are in dispute with Kinder Morgan (as successor in interest to GATX) regarding the indemnity by GATX in favor of Pacific in connection with Pacific’s purchase of the facility. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the MTBE contamination.

New Jersey Dep’t of Environmental Protection v. ExxonMobil Corp. et al. In a matter related to ExxonMobil v. GATX, in June 2007, the NJDEP brought suit against GATX and Exxon to recover natural resources damages associated with, and to require remediation of, the contamination. ExxonMobil and GATX have filed third-party demands against PAT, seeking indemnity and contribution. NJDEP environmental consultants have asserted a significant clean-up expense as indicated. Discussions with the NJDEP have commenced.

EPA v. Rocky Mountain Pipeline System. In February 2009, we received a request for information from EPA regarding aspects of the fuel handling activities of Rocky Mountain Pipeline System (“RMPS”), a subsidiary acquired in the Pacific merger, at two truck terminals in Colorado. These activities, performed at the request of customers, included the mixture of certain blendstocks with gasoline. We provided the information requested, and cooperated in EPA's investigation of such activities. In January 2010, we received a notice of violations from EPA, alleging failure of RMPS to comply with provisions of the Clean Air Act ("CAA") related to registration, sampling, recording and reporting in connection with such activities. EPA further alleges that the violations occurred on an ongoing basis from October 2006 through February 2009. We plan to engage in discussion with EPA, and to emphasize factors intended to mitigate the severity of any penalties imposed. In December 2009, RMPS self-reported late filing of certain reports required under Clean Air Act Diesel Fuel Regulations. All reports have been filed.

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

General. We, in the ordinary course of business, are a claimant and/or a defendant in various legal proceedings. To the extent we are able to assess the likelihood of a negative outcome for these proceedings, our assessments of such likelihood range from remote to probable. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We do not believe that the outcome of these legal proceedings, individually or in the aggregate, will have a materially adverse effect on our financial condition, results of operations or cash flows.

Environmental

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 an inspection program designed to help prevent releases, damages and liabilities incurred due to any such releases from our assets may substantially affect our business. As we expand our pipeline assets through acquisitions, we typically improve on (reduce) the releases from such assets (in terms of frequency or volume) as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. However, the inclusion of additional miles of pipe in our operations may result in an increase in the absolute number of releases company-wide compared to prior periods. We experienced such an increase in connection with the Pacific acquisition, which added approximately 5,000 miles of pipeline to our operations, and in connection with the purchase of assets from Link in April 2004, which added approximately 7,000 miles of pipeline to our operations. As a result, we have also received an increased number of requests for information from governmental agencies with respect to such releases of crude oil (such as EPA requests under Clean Water Act Section 308), commensurate with the scale and scope of our pipeline operations, 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. See "—Pipeline Releases" above.

At December 31, 2009, our reserve for environmental liabilities totaled approximately $62 million, of which approximately $10 million is classified as short-term and $52 million is classified as long-term. At December 31, 2009, we have recorded receivables totaling approximately $3 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

In some cases, the actual cash expenditures may not occur for three to five years. Our estimates used in these reserves are based on known facts and believed to be relevant at the time and our assessment of the ultimate outcome. Among the many uncertainties that impact our estimates are the necessary regulatory approvals for, and potential modification of, our remediation plans, the limited amount of data available upon initial assessment of the impact of soil or water contamination, changes in costs associated with environmental remediation services and equipment and the possibility of existing legal claims giving rise to additional claims. Therefore, although we believe that the reserve is adequate, costs incurred may be in excess of the reserve and may potentially have a material adverse effect on our financial condition, results of operations, or cash flows.

Insurance

A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and 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 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 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 and wind damage exposures, incorporate higher retention in our insurance arrangements, pay higher premiums or some combination of such actions.

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 12—Environmental Remediation

We currently own or lease, and in the past have owned and leased, properties where hazardous liquids, including hydrocarbons, are or have been handled. These properties and the hazardous liquids or associated wastes disposed thereon may be subject to CERCLA, RCRA and state and Canadian federal and provincial laws and regulations. Under such laws and regulations, we could be required to remove or remediate hazardous liquids or associated wastes (including wastes disposed of or released by prior owners or operators) and to clean up contaminated property (including contaminated groundwater).

We maintain insurance of various types with varying levels of coverage that we consider adequate under the circumstances to cover our operations and properties. The insurance policies are subject to deductibles and retention levels that we consider reasonable and not excessive. Consistent with insurance coverage generally available in the industry, in certain circumstances our insurance policies provide limited coverage for losses or liabilities relating to gradual pollution, with broader coverage for sudden and accidental occurrences.

In conjunction with our acquisitions, we typically make an assessment of potential environmental exposure and determine whether to negotiate an indemnity, what the terms of any indemnity should be and whether to obtain environmental risk insurance, if available. These contractual indemnifications typically are subject to specific monetary requirements that must be satisfied before indemnification will apply, and have term and total dollar limits. For instance, in connection with the purchase of former Texas New Mexico ("TNM") pipeline assets from Link in 2004, we identified a number of environmental liabilities for which we received a purchase price reduction from Link and recorded a total environmental reserve of $20 million, of which we agreed in an arrangement with TNM to bear the first $11 million in costs of pre-May 1999 environmental issues. TNM also agreed to pay all costs in excess of $20 million (excluding certain deductibles). TNM's obligations are guaranteed by Shell Oil Products ("SOP"). As of December 31, 2009, we had incurred approximately $16 million of remediation costs associated with these sites, while SOP's share has been approximately $6 million. In another example, as a result of our merger with Pacific, we assumed liability for a number of ongoing remediation sites associated with releases from pipeline or storage operations. We have evaluated each of the sites requiring remediation and developed reserve estimates for the Pacific sites, which total approximately $18 million at December 31, 2009.

In connection with the acquisition of certain crude oil transmission and gathering assets from SOP in 2002, SOP purchased an environmental insurance policy covering known and unknown environmental matters associated with operations prior to closing. We are a named beneficiary under the policy, which has a $100,000 deductible per site, an aggregate coverage limit of $70 million, and expires in 2012.

Other assets we have acquired or will acquire in the future may have environmental remediation liabilities for which we are not indemnified.

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. See Note 11 for further environmental discussion.

Note 13—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:

- we are referred to as “Parent;”

- the “Guarantor Subsidiaries” are all subsidiaries other than the Non-Guarantor subsidiaries defined below; and

- The “Non-Guarantor Subsidiaries” as of December 31, 2009 include two California Public Utilities Commission regulated entities, our natural gas storage subsidiaries and other minor 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 Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent's investments in its subsidiaries and the Guarantor Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting (in millions):

Condensed Consolidating Balance Sheet

	As of December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 3,428	$ 3,831	$ 209	$ (3,810)	$ 3,658
Property, plant and equipment, net	—	4,606	1,734	—	6,340
Investment in unconsolidated entities	5,295	1,652	—	(6,865)	82
Other assets	29	2,342	367	(460)	2,278
Total assets	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 456	$ 6,849	$ 287	$ (3,810)	$ 3,782
Long-term debt	4,137	15	450	(460)	4,142
Other long-term liabilities	—	271	4	—	275
Total liabilities	4,593	7,135	741	(4,270)	8,199
Partners' capital excluding noncontrolling interest	4,096	5,233	1,569	(6,802)	4,096
Noncontrolling interest	63	63	—	(63)	63
Total partners' capital	4,159	5,296	1,569	(6,865)	4,159
Total liabilities and partners' capital	$ 8,752	$ 12,431	$ 2,310	$ (11,135)	$ 12,358

	As of December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$ 2,698	$ 2,789	$ 110	$ (3,001)	$ 2,596
Property, plant and equipment, net	—	4,410	649	—	5,059
Investment in unconsolidated entities	4,388	895	—	(5,026)	257
Other assets	27	1,777	316	—	2,120
Total assets	$ 7,113	$ 9,871	$ 1,075	$ (8,027)	$ 10,032
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 304	$ 5,411	$ 246	$ (3,001)	$ 2,960
Long-term debt	3,257	2	—	—	3,259
Other long-term liabilities	—	260	1	—	261
Total liabilities	3,561	5,673	247	(3,001)	6,480
Partners' capital excluding noncontrolling interest	3,552	4,198	828	(5,026)	3,552
Noncontrolling interest	—	—	—	—	—
Total partners' capital	3,552	4,198	828	(5,026)	3,552
Total liabilities and partners' capital	$ 7,113	$ 9,871	$ 1,075	$ (8,027)	$ 10,032

Condensed Consolidating Statements of Operations

	Twelve Months Ended December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues[1]	$ —	$ 1,707	$ 157	$ —	$ 1,864
Field operating costs	—	(589)	(49)	—	(638)
General and administrative expenses	—	(196)	(15)	—	(211)
Depreciation and amortization	(4)	(200)	(32)	—	(236)
Operating income/(loss)	(4)	722	61	—	779
Equity earnings in unconsolidated entities	822	64	—	(871)	15
Interest income (expense)	(234)	14	(4)	—	(224)
Other income, net	(4)	20	—	—	16
Income tax expense	—	(6)	—	—	(6)
Net income	580	814	57	(871)	580
Less: Net income attributable to noncontrolling interest	(1)	(1)	—	1	(1)
Net income attributable to Plains	$ 579	$ 813	$ 57	$ (870)	$ 579

	Year Ended December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 1,469	$ 113	$ —	$ 1,582
Field operating costs	—	(575)	(42)	—	(617)
General and administrative expenses	—	(149)	(11)	—	(160)
Depreciation and amortization	(3)	(187)	(21)	—	(211)
Operating income/(loss)	(3)	558	39	—	594
Equity earnings in unconsolidated entities	629	45	—	(660)	14
Interest expense	(195)	(1)	—	—	(196)
Other income, net	6	26	1	—	33
Income tax expense	—	(8)	—	—	(8)
Net income	$ 437	$ 620	$ 40	$ (660)	$ 437

	Year Ended December 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues [1]	$ —	$ 1,271	$ 122	$ —	$ 1,393
Field operating costs	—	(493)	(38)	—	(531)
General and administrative expenses	—	(161)	(3)	—	(164)
Depreciation and amortization	(3)	(157)	(20)	—	(180)
Operating income/(loss)	(3)	460	61	—	518
Equity earnings in unconsolidated entities	524	66	—	(575)	15
Interest expense	(161)	(1)	—	—	(162)
Other income, net	5	5	—	—	10
Income tax expense	—	(16)	—	—	(16)
Net income	$ 365	$ 514	$ 61	$ (575)	$ 365

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

	Year Ended December 31, 2009				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 580	$ 814	$ 57	$ (871)	$ 580
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	4	200	32	—	236
Equity compensation expense	—	67	1	—	68
Equity earnings in unconsolidated entities	(818)	(61)	—	871	(8)
Other	—	(50)	—	—	(50)
Changes in assets and liabilities, net of acquisitions	(616)	165	(10)	—	(461)
Net cash provided by/(used in) operating activities	(850)	1,135	80	—	365
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	—	(219)	—	—	(219)
Additions to property and equipment	—	(387)	(73)	—	(460)
Investment in unconsolidated entities	(4)	—	—	—	(4)
Cash received for sale of noncontrolling interest in a subsidiary	—	26	—	—	26
Net cash paid for linefill in assets owned	—	(9)	—	—	(9)
Proceeds from sales of assets and other	—	6	—	—	6
Net cash used in investing activities	(4)	(583)	(73)	—	(660)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings on revolving credit facility	95	(114)	—	—	(19)
Net repayments on short-term letter of credit and hedged inventory facility	—	20	—	—	20
Repayment of PNGS debt	—	(446)	—	—	(446)
Proceeds from issuance of senior notes	1,346	—	—	—	1,346
Repayments of senior notes	(430)	—	—	—	(430)
Net proceeds from the issuance of common units	458	—	—	—	458
Distributions paid to common unitholders and general partner	(605)	—	—	—	(605)
Other financing activities	(11)	1	(2)	—	(12)
Net cash provided by/(used in) financing activities	853	(539)	(2)	—	312
Effect of translation adjustment on cash	—	(3)	—	—	(3)
Net increase/(decrease) in cash and cash equivalents	(1)	10	5	—	14
Cash and cash equivalents, beginning of period	2	9	—	—	11
Cash and cash equivalents, end of period	$ 1	$ 19	$ 5	$ —	$ 25

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2008				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 437	$ 620	$ 40	$ (660)	$ 437
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	3	187	21	—	211
Inventory valuation adjustment	—	168	—	—	168
Equity compensation expense	—	24	—	—	24
Gain on foreign currency revaluation	—	22	—	—	22
Equity earnings in unconsolidated entities, net of distributions	(622)	(42)	—	660	(4)
Deferred income tax benefit	—	(1)	—	—	(1)
Other	17	(15)	—	—	2
Changes in assets and liabilities, net of acquisitions	(375)	389	(16)	—	(2)
Net cash provided by/(used in) operating activities	(540)	1,352	45	—	857
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	—	(709)	—	—	(709)
Additions to property and equipment	—	(544)	(45)	—	(589)
Investment in unconsolidated entities	(37)	—	—	—	(37)
Net cash paid for linefill in assets owned	—	(55)	—	—	(55)
Proceeds from sales of assets and other	—	51	—	—	51
Net cash used in investing activities	(37)	(1,257)	(45)	—	(1,339)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings on revolving credit facility	204	82	—	—	286
Net repayments on short-term letter of credit and hedged inventory facility	—	(196)	—	—	(196)
Proceeds from issuance of senior notes	597	—	—	—	597
Net proceeds from the issuance of common units	315	—	—	—	315
Distributions paid to common unitholders and general partner	(532)	—	—	—	(532)
Other financing activities	(6)	—	—	—	(6)
Net cash provided by/(used in) financing activities	578	(114)	—	—	464
Effect of translation adjustment on cash	—	5	—	—	5
Net increase/(decrease) in cash and cash equivalents	1	(14)	—	—	(13)
Cash and cash equivalents, beginning of period	1	23	—	—	24
Cash and cash equivalents, end of period	$ 2	$ 9	$ —	$ —	$ 11

	Condensed Consolidating Statements of Cash Flows Year Ended December 31, 2007				
	Parent	**Combined Guarantor Subsidiaries**	**Combined Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 365	$ 514	$ 61	$ (575)	$ 365
Reconciliation of net income to net cash provided by operating activities:					
Depreciation and amortization	3	157	20	—	180
Equity compensation expense	—	49	—	—	49
Equity earnings in unconsolidated entities, net of distributions	(524)	(65)	—	575	(14)
Deferred income tax expense	—	13	—	—	13
Other	—	(14)	—	—	(14)
Changes in assets and liabilities, net of acquisitions	232	42	(57)	—	217
Net cash provided by operating activities	76	696	24	—	796
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of cash acquired	—	(127)	—	—	(127)
Additions to property and equipment	—	(524)	(24)	—	(548)
Investment in unconsolidated entities	(9)	—	—	—	(9)
Cash paid for linefill in assets owned	—	(19)	—	—	(19)
Proceeds from sales of assets and other	—	40	—	—	40
Net cash used in investing activities	(9)	(630)	(24)	—	(663)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net borrowings on revolving credit facility	—	305	—	—	305
Net repayments on short-term letter of credit and hedged inventory facility	—	(359)	—	—	(359)
Net proceeds from the issuance of common units	383	—	—	—	383
Distributions paid to common unitholders and general partner	(451)	—	—	—	(451)
Other financing activities	—	(2)	—	—	(2)
Net cash used in financing activities	(68)	(56)	—	—	(124)
Effect of translation adjustment on cash	—	4	—	—	4
Net increase/(decrease) in cash and cash equivalents	(1)	14	—	—	13
Cash and cash equivalents, beginning of period	2	9	—	—	11
Cash and cash equivalents, end of period	$ 1	$ 23	$ —	$ —	$ 24

Note 14—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total [(1)]
		(in millions, except per unit data)			
2009					
Revenues	$ 3,302	$ 4,282	$ 4,857	$ 6,078	$ 18,520
Gross margin [(2)]	$ 302	$ 237	$ 218	$ 231	$ 990
Operating income	$ 256	$ 183	$ 166	$ 173	$ 779
Net income	$ 211	$ 136	$ 122	$ 110	$ 580
Net income attributable to Plains	$ 211	$ 136	$ 122	$ 110	$ 579
Basic net income per limited partner unit	$ 1.42	$ 0.79	$ 0.65	$ 0.53	$ 3.34
Diluted net income per limited partner unit	$ 1.41	$ 0.78	$ 0.65	$ 0.52	$ 3.32
Cash distributions per common unit [(3)]	$ 0.8925	$ 0.9050	$ 0.9050	$ 0.9200	$ 3.62
2008					
Revenues	$ 7,195	$ 9,060	$ 8,862	$ 4,943	$ 30,061
Gross margin [(2)]	$ 167	$ 132	$ 282	$ 173	$ 754
Operating income	$ 127	$ 81	$ 243	$ 142	$ 594
Net income	$ 92	$ 41	$ 206	$ 98	$ 437
Basic net income per limited partner unit	$ 0.56	$ 0.09	$ 1.42	$ 0.56	$ 2.66
Diluted net income per limited partner unit	$ 0.56	$ 0.09	$ 1.41	$ 0.56	$ 2.64
Cash distributions per common unit [(3)]	$ 0.8500	$ 0.8650	$ 0.8875	$ 0.8925	$ 3.50

(1) The sum of the four quarters may not equal the total year due to rounding.

(2) Gross margin is calculated as Total revenues less (i) Purchases and related costs, (ii) Field operating costs and (iii) Depreciation and amortization.

(3) Represents cash distributions declared and paid in the applicable period.

Note 15—Operating Segments

We manage our operations through three operating segments: (i) Transportation, (ii) Facilities, and (iii) Supply and Logistics. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates 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 acts 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 for the replacement of partially or fully depreciated assets in order to maintain the service capability, level of production, and/or functionality of our existing assets. Capital expenditures made to expand the existing earnings capacity of our assets are considered expansion capital expenditures, not maintenance capital. Repair and maintenance expenditures incurred in order to maintain the day to day operation of our existing assets are charged to expense as incurred. The following table reflects certain financial data for each segment for the periods indicated (in millions).

	Transportation	Facilities	Supply & Logistics	Total
Twelve Months Ended December 31, 2009				
Revenues:				
External Customers	$ 536	$ 227	$ 17,757	$ 18,520
Intersegment [1]	425	135	2	562
Total revenues of reportable segments	$ 961	$ 362	$ 17,759	$ 19,082
Equity in earnings of unconsolidated entities	$ 7	$ 8	$ —	$ 15
Segment profit [2] [3] [4]	$ 477	$ 208	$ 345	$ 1,030
Capital expenditures	$ 183	$ 564	$ 10	$ 757
Total assets	$ 4,468	$ 3,097	$ 4,793	$ 12,358
Maintenance capital	$ 57	$ 16	$ 8	$ 81
Twelve Months Ended December 31, 2008				
Revenues:				
External Customers	$ 556	$ 157	$ 29,348	$ 30,061
Intersegment [1]	371	113	2	486
Total revenues of reportable segments	$ 927	$ 270	$ 29,350	$ 30,547
Equity in earnings of unconsolidated entities	$ 5	$ 9	$ —	$ 14
Segment profit [2] [3] [4]	$ 445	$ 153	$ 221	$ 819
Capital expenditures	$ 935	$ 265	$ 26	$ 1,226
Total assets	$ 3,930	$ 2,048	$ 4,054	$ 10,032
Maintenance capital	$ 54	$ 23	$ 4	$ 81
Twelve Months Ended December 31, 2007				
Revenues:				
External Customers	$ 439	$ 121	$ 19,834	$ 20,394
Intersegment [1]	332	89	24	445
Total revenues of reportable segments	$ 771	$ 210	$ 19,858	$ 20,839
Equity in earnings of unconsolidated entities	$ 5	$ 10	$ —	$ 15
Segment profit [2] [3] [4]	$ 334	$ 110	$ 269	$ 713
Capital expenditures	$ 255	$ 348	$ 47	$ 650
Total assets	$ 3,127	$ 1,754	$ 5,025	$ 9,906
Maintenance capital	$ 34	$ 10	$ 6	$ 50

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(1) Segment revenues and purchases and related costs include intersegment amounts. Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates.

(2) Gains/losses from derivative activities are primarily included in supply and logistics revenues and impact segment profit.

(3) Supply and logistics segment profit includes interest expense on contango inventory purchases of $11 million, $21 million and $44 million for the years ended December 31, 2009, 2008 and 2007, respectively.

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

	Year ended December 31, 2009	2008	2007
Segment profit	$ 1,030	$ 819	$ 713
Depreciation and amortization	(236)	(211)	(180)
Interest expense	(224)	(196)	(162)
Other income, net	16	33	10
Income tax expense	(6)	(8)	(16)
Net income	580	437	365
Less: Net income attributable to noncontrolling interest	(1)	—	—
Net income attributable to Plains	$ 579	$ 437	$ 365

Geographic Data

We have operations in the United States and Canada. Set forth below are revenues and long lived assets attributable to these geographic areas (in millions):

Revenues [1]	For the Year Ended December 31, 2009	2008	2007
United States	$ 15,439	$ 25,183	$ 16,843
Canada	3,081	4,878	3,551
	$ 18,520	$ 30,061	$ 20,394

(1) Revenues are attributed to each region based on where the customers are located.

Long-Lived Assets [1]	As of December 31, 2009	2008
United States	$ 6,945	$ 5,976
Canada	1,678	1,312
	$ 8,623	$ 7,288

(1) Excludes long-term derivative assets.

EXHIBIT INDEX

3.1	—	Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. dated as of June 27, 2001 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 27, 2001).
3.2	—	Amendment No. 1 dated April 15, 2004 to the Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.3	—	Amendment No. 2 dated November 15, 2006 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed November 21, 2006).
3.4	—	Amendment No. 3 dated August 16, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 22, 2007).
3.5	—	Amendment No. 4 effective as of January 1, 2007 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed April 15, 2008).
3.6	—	Amendment No. 5 dated May 28, 2008 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed May 30, 2008).
3.7	—	Amendment No. 6 dated September 3, 2009 to Third Amended and Restated Agreement of Limited Partnership of Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed September 3, 2009).
3.8	—	Third Amended and Restated Agreement of Limited Partnership of Plains Marketing, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.9	—	Third Amended and Restated Agreement of Limited Partnership of Plains Pipeline, L.P. dated as of April 1, 2004 (incorporated by reference to Exhibit 3.3 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2004).
3.10	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008, as amended November 2, 2009 (incorporated by reference to Exhibit 3.10 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2009).
3.11	—	Fifth Amended and Restated Limited Partnership Agreement of Plains AAP, L.P. dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.12	—	Certificate of Incorporation of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.10 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.13	—	Bylaws of PAA Finance Corp (f/k/a Pacific Energy Finance Corporation, successor-by-merger to PAA Finance Corp.) (incorporated by reference to Exhibit 3.11 to the Annual Report on Form 10-K for the year ended December 31, 2006).
3.14	—	Limited Liability Company Agreement of PAA GP LLC dated December 28, 2007 (incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K filed January 4, 2008).

4.1	—	Indenture dated September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp. and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.2	—	First Supplemental Indenture (Series A and Series B 7.75% Senior Notes due 2012) dated as of September 25, 2002 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2002).
4.3	—	Second Supplemental Indenture (Series A and Series B 5.625% Senior Notes due 2013) dated as of December 10, 2003 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to the Annual Report on Form 10-K for the year ended December 31, 2003).
4.4	—	Fourth Supplemental Indenture (Series A and Series B 5.875% Senior Notes due 2016) dated August 12, 2004 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	Fifth Supplemental Indenture (Series A and Series B 5.25% Senior Notes due 2015) dated May 27, 2005 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 31, 2005).
4.6	—	Sixth Supplemental Indenture (Series A and Series B 6.70% Senior Notes due 2036) dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed May 12, 2006).
4.7	—	Seventh Supplemental Indenture dated May 12, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed May 12, 2006).
4.8	—	Eighth Supplemental Indenture dated August 25, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and Wachovia Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed August 25, 2006).
4.9	—	Ninth Supplemental Indenture (Series A and Series B 6.125% Senior Notes due 2017) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed October 30, 2006).
4.10	—	Tenth Supplemental Indenture (Series A and Series B 6.650% Senior Notes due 2037) dated October 30, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed October 30, 2006).
4.11	—	Eleventh Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed November 21, 2006).
4.12	—	Twelfth Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.21 to the Annual Report on Form 10-K for the year ended December 31, 2007).

4.13	—	Thirteenth Supplemental Indenture (Series A and Series B 6.5% Senior Notes due 2018) dated April 23, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 23, 2008).
4.14	—	Fourteenth Supplemental Indenture dated July 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.15 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2008).
4.15	—	Fifteenth Supplemental Indenture (8.75% Senior Notes due 2019) dated April 20, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed April 20, 2009).
4.16	—	Sixteenth Supplemental Indenture (4.25% Senior Notes due 2012) dated July 23, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed July 23, 2009).
4.17	—	Seventeenth Supplemental Indenture (5.75% Senior Notes due 2020) dated September 4, 2009 among Plains All American Pipeline, L.P., PAA Finance Corp., the Subsidiary Guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed September 4, 2009).
4.18	—	Indenture dated September 23, 2005 among Pacific Energy Partners, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee of the $6^1/_4$% senior notes due 2015 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed September 28, 2005).
4.19	—	First Supplemental Indenture dated November 15, 2006 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to the Current Report on Form 8-K filed November 21, 2006).
4.20	—	Second Supplemental Indenture dated January 1, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp. (f/k/a Pacific Energy Finance Corporation), the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.22 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.21	—	Registration Rights Agreement dated September 3, 2009 by and between Plains All American Pipeline, L.P. and Vulcan Gas Storage LLC (incorporated by reference to Exhibit 4.1 to the Registration Statement on Form S-3, File No. 333-162477).
10.1	—	Restated Credit Facility (Uncommitted Senior Secured Discretionary Contango Facility) dated November 19, 2004 among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 24, 2004).
10.2	—	Amended and Restated Crude Oil Marketing Agreement dated as of July 23, 2004, among Plains Resources Inc., Calumet Florida Inc. and Plains Marketing, L.P. (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).
10.3	—	Amended and Restated Omnibus Agreement dated as of July 23, 2004, among Plains Resources Inc., Plains All American Pipeline, L.P., Plains Marketing, L.P., Plains Pipeline, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).

10.4	—	Contribution, Assignment and Amendment Agreement dated as of June 27, 2001, among Plains All American Pipeline, L.P., Plains Marketing, L.P., All American Pipeline, L.P., Plains AAP, L.P., Plains All American GP LLC and Plains Marketing GP Inc. (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 27, 2001).
10.5	—	Contribution, Assignment and Amendment Agreement dated as of June 8, 2001, among Plains All American Inc., Plains AAP, L.P. and Plains All American GP LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 11, 2001).
10.6	—	Separation Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc., Plains All American GP LLC, Plains AAP, L.P. and Plains All American Pipeline, L.P. (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed June 11, 2001).
10.7**	—	Pension and Employee Benefits Assumption and Transition Agreement dated as of June 8, 2001 among Plains Resources Inc., Plains All American Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed June 11, 2001).
10.8**	—	Plains All American GP LLC 2005 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 26, 2005).
10.9**	—	Plains All American GP LLC 1998 Long-Term Incentive Plan (incorporated by reference to Exhibit 99.1 to Registration Statement on Form S-8, File No. 333-74920) as amended June 27, 2003 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2003).
10.10**	—	Plains All American 2001 Performance Option Plan (incorporated by reference to Exhibit 99.2 to the Registration Statement on Form S-8 filed December 11, 2001, File No. 333-74920).
10.11**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Greg L. Armstrong dated as of June 30, 2001 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.12**	—	Amended and Restated Employment Agreement between Plains All American GP LLC and Harry N. Pefanis dated as of June 30, 2001 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2001).
10.13	—	Asset Purchase and Sale Agreement dated February 28, 2001 between Murphy Oil Company Ltd. and Plains Marketing Canada, L.P. (incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed May 10, 2001).
10.14	—	Transportation Agreement dated July 30, 1993, between All American Pipeline Company and Exxon Company, U.S.A. (incorporated by reference to Exhibit 10.9 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.15	—	Transportation Agreement dated August 2, 1993, among All American Pipeline Company, Texaco Trading and Transportation Inc., Chevron U.S.A. and Sun Operating Limited Partnership (incorporated by reference to Exhibit 10.10 to the Registration Statement on Form S-1 filed September 23, 1998, File No. 333-64107).
10.16	—	First Amendment to Contribution, Conveyance and Assumption Agreement dated as of December 15, 1998 (incorporated by reference to Exhibit 10.13 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.17	—	Agreement for Purchase and Sale of Membership Interest in Scurlock Permian LLC between Marathon Ashland LLC and Plains Marketing, L.P. dated as of March 17, 1999 (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 1998).
10.18**	—	Plains All American Inc. 1998 Management Incentive Plan (incorporated by reference to Exhibit 10.5 to the Annual Report on Form 10-K for the year ended December 31, 1998).

10.19**	—	PMC (Nova Scotia) Company Bonus Program (incorporated by reference to Exhibit 10.20 to the Annual Report on Form 10-K for the year ended December 31, 2004).
10.20**	—	Quarterly Bonus Program Summary (incorporated by reference to Exhibit 10.21 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.21**†	—	Directors' Compensation Summary.
10.22	—	Master Railcar Leasing Agreement dated as of May 25, 1998 (effective June 1, 1998), between Pivotal Enterprises Corporation and CANPET Energy Group, Inc., (incorporated by reference to Exhibit 10.16 to the Annual Report on Form 10-K for the year ended December 31, 2001).
10.23**	—	Form of LTIP Grant Letter (Armstrong/Pefanis) (incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.24**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed April 1, 2005).
10.25**	—	Form of LTIP Grant Letter (independent directors) (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed February 23, 2005).
10.26**	—	Form of LTIP Grant Letter (designated directors) (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed February 23, 2005).
10.27**	—	Form of LTIP Grant Letter (payment to entity) (incorporated by reference to Exhibit 10.5 to the Current Report on Form 8-K filed February 23, 2005).
10.28**	—	Form of Performance Option Grant Letter (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed April 1, 2005).
10.29	—	Administrative Services Agreement between Plains All American GP LLC and Vulcan Energy Corporation dated October 14, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed October 19, 2005).
10.30	—	Membership Interest Purchase Agreement by and between Sempra Energy Trading Corp. and PAA/Vulcan Gas Storage, LLC dated August 19, 2005 (incorporated by reference to Exhibit 1.2 to the Current Report on Form 8-K filed September 19, 2005).
10.31**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 16, 2005).
10.32**	—	Waiver Agreement dated as of August 12, 2005 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed August 16, 2005).
10.33	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Vulcan Energy GP Holdings Inc. and Plains All American GP LLC (incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed August 16, 2005).
10.34	—	Excess Voting Rights Agreement dated as of August 12, 2005 between Lynx Holdings I, LLC and Plains All American GP LLC (incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed August 16, 2005).
10.35**	—	Form of LTIP Grant Letter (executive officers) (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2005).

10.36**	—	Employment Agreement between Plains All American GP LLC and John P. vonBerg dated December 18, 2001 (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2005).
10.37**	—	Form of LTIP Grant Letter (audit committee members) (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 23, 2006).
10.38**	—	Plains All American PPX Successor Long-Term Incentive Plan (incorporated by reference to Exhibit 10.45 to the Annual Report on Form 10-K for the year ended December 31, 2006).
10.39**	—	Forms of LTIP Grant Letters dated February 22, 2007 (Named Executive Officers) (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2007).
10.40	—	First Amendment dated July 31, 2007 to the Second Amended and Restated Credit Agreement [US/Canada Facilities] by and between Plains All American Pipeline, L.P., PMC (Nova Scotia) Company, Plains Marketing Canada, L.P., Rangeland Pipeline Company, Bank of America, N.A., as Administrative Agent, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed August 6, 2007).
10.41**	—	Separation and Release Agreement dated August 21, 2007 between Plains All American GP LLC and George R. Coiner (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2007).
10.42**	—	Form of Plains AAP, L.P. Class B Restricted Units Agreement (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed January 4, 2008).
10.43	—	Second Restated Credit Agreement dated as of November 6, 2008 by among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, and the Lenders party there to (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed November 7, 2008).
10.44	—	First Amendment to Second Restated Credit Agreement dated as of October 27, 2009, by and among Plains Marketing, L.P., Bank of America, N.A., as Administrative Agent, BNP Paribas, as Syndication Agent, SOCIETE GENERALE, as Documentation Agent, Banc of America Securities LLC (“BAS”), BNP Paribas (“BNPP”) and Societe Generale, as joint lead arrangers, BAS and BNPP, as joint bookrunners, and the Lenders party thereto (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed October 29, 2009).
10.45	—	Restated Guaranty Agreement dated November 6, 2008 by Plains All American Pipeline, L.P. in favor of Bank of America, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed November 7, 2008).
10.46	—	Contribution and Assumption Agreement, dated December 28, 2007, by and between Plains AAP, L.P. and PAA GP LLC (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed January 4, 2008).
10.47	—	Assumption, Ratification and Confirmation Agreement dated January 1, 2008 by Plains Midstream Canada ULC in favor of the Lenders party to the Second Amended and Restated Credit Agreement [US/Canada Facilities], as amended (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2007).
10.48**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.49**	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2008).

10.50**	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.51**	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008 (incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.52**	—	Form of Amendment to LTIP grant letters dated December 4, 2008 (executive officers) (incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K for the year ended December 31, 2008).
10.53**	—	Form of Amendment to LTIP grant letters (directors) (incorporated by reference to Exhibit 10.54 to the Annual Report on Form 10-K for the year ended December 31, 2008).
12.1†	—	Computation of Ratio of Earnings to Fixed Charges.
21.1†	—	List of Subsidiaries of Plains All American Pipeline, L.P.
23.1†	—	Consent of PricewaterhouseCoopers LLP.
31.1†	—	Certification of Principal Executive Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
31.2†	—	Certification of Principal Financial Officer pursuant to Exchange Act Rules 13a-14(a) and 15d-14(a).
32.1†	—	Certification of Principal Executive Officer pursuant to 18 U.S.C. 1350
32.2†	—	Certification of Principal Financial Officer pursuant to 18 U.S.C. 1350
101†	—	The following financial information from the annual report on Form 10-K of Plains All American Pipeline, L.P. for the year ended December 31, 2009, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Statements of Operations, (ii) Consolidated Balance Sheets, (iii) Consolidated Statements of Cash Flows, (iv) Consolidated Statements of Changes in Partners' Capital, (v) Consolidated Statements of Comprehensive Income, (vi) Consolidated Statements of Changes in Accumulated Comprehensive Income and (vii) Notes to the Consolidated Financial Statements, tagged as blocks of text.

† Filed herewith

** Management compensatory plan or arrangement