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	—	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).
3.8	—	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).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008 (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed August 7, 2008).
3.10	—	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).

3.11	—	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).
3.12	—	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).
3.13	—	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	—	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) 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 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	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).
4.6	—	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).
4.7	—	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).

4.8	—	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).
4.9	—	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).
4.10	—	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).
4.11	—	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).
4.12	—	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).
4.13	—	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).
4.14	—	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).
4.15	—	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).
4.16	—	Indenture dated June 16, 2004 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 7⅛% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).

4.17	—	First Supplemental Indenture dated March 3, 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 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed March 9, 2005).
4.18	—	Second Supplemental 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 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).
4.19	—	Third 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 4.2 to the Current Report on Form 8-K filed November 21, 2006).
4.20	—	Fourth 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 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).
4.21†	—	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee.
4.22	—	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 6¼% 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).
4.23	—	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).
4.24	—	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).

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 JPMorgan 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	—	Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed September 19, 2005).
10.31	—	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).
10.32**	—	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).
10.33**	—	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).
10.34	—	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).
10.35	—	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).
10.36**	—	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).
10.37**	—	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).

10.38	—	First Amendment dated May 9, 2006 to the Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 15, 2006).
10.39**	—	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).
10.40**	—	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).
10.41**	—	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).
10.42	—	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).
10.43**	—	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).
10.44**	—	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).
10.45	—	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).
10.46	—	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).
10.47	—	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).
10.48	—	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).
10.49**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong.
10.50**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis.

10.51**†	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008.
10.52**†	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008.
10.53**†	—	Form of Amendment to LTIP grant letters (executive officers).
10.54**†	—	Form of Amendment to LTIP grant letters (directors).
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

† 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, 2009

By: /s/ AL SWANSON

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

February 26, 2009

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, 2009
/s/ HARRY N. PEFANIS Harry N. Pefanis	President and Chief Operating Officer of Plains All American GP LLC	February 26, 2009
/s/ AL SWANSON Al Swanson	Senior Vice President and Chief Financial Officer of Plains All American GP LLC (Principal Financial Officer)	February 26, 2009
/s/ TINA L. VAL Tina L. Val	Vice President—Accounting and Chief Accounting Officer of Plains All American GP LLC (Principal Accounting Officer)	February 26, 2009
/s/ W. LANCE CONN W. Lance Conn	Director of Plains All American GP LLC	February 26, 2009
/s/ EVERARDO GOYANES Everardo Goyanes	Director of Plains All American GP LLC	February 26, 2009
/s/ GARY R. PETERSEN Gary R. Petersen	Director of Plains All American GP LLC	February 26, 2009
/s/ ROBERT V. SINNOTT Robert V. Sinnott	Director of Plains All American GP LLC	February 26, 2009
/s/ ARTHUR L. SMITH Arthur L. Smith	Director of Plains All American GP LLC	February 26, 2009
/s/ J. TAFT SYMONDS J. Taft Symonds	Director of Plains All American GP LLC	February 26, 2009

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, 2008.

The effectiveness of the Partnership's internal control over financial reporting as of December 31, 2008 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, 2009

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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, 2008, 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.

As discussed in Note 1 to the consolidated financial statements, the Partnership changed the manner in which it accounts for equity-based compensation and purchases and sales with the same counterparty in 2006.

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 **PricewaterhouseCoopers LLP**
February 26, 2009

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2008	December 31, 2007
	(in millions, except unit amounts)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 11	$ 24
Trade accounts receivable and other receivables, net	1,525	2,561
Inventory	801	972
Other current assets	259	116
Total current assets	2,596	3,673
PROPERTY AND EQUIPMENT	5,727	4,938
Accumulated depreciation	(668)	(519)
	5,059	4,419
OTHER ASSETS		
Pipeline linefill in owned assets	425	284
Long-term inventory	139	74
Investment in unconsolidated entities	257	215
Goodwill	1,210	1,072
Other, net	346	169
Total assets	$10,032	$9,906
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	$ 1,507	$2,577
Short-term debt	1,027	960
Other current liabilities	426	192
Total current liabilities	2,960	3,729
LONG-TERM LIABILITIES		
Long-term debt under credit facilities and other	40	1
Senior notes, net of unamortized net discount of $6 and $2, respectively	3,219	2,623
Other long-term liabilities and deferred credits	261	129
Total long-term liabilities	3,520	2,753
COMMITMENTS AND CONTINGENCIES (NOTE 11)		
PARTNERS' CAPITAL		
Common unitholders (122,911,645 and 115,981,676 units outstanding, respectively)	3,469	3,343
General partner	83	81
Total partners' capital	3,552	3,424
Total liabilities and partners' capital	$10,032	$9,906

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

PLAINS ALL AMERICAN PIPELINE, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2008	2007	2006
	(in millions, except per unit data)		
REVENUES			
Crude oil, refined products and LPG sales and related revenues (includes buy/sell transactions of $4,762 for the 2006 period)	$29,348	$19,834	$22,060
Pipeline tariff activities, trucking and related revenues	556	439	344
Storage, terminalling, processing and related revenues	157	121	41
Total revenues	30,061	20,394	22,445
COSTS AND EXPENSES			
Crude oil, refined products and LPG purchases and related costs (includes buy/sell transactions of $4,795 for the 2006 period)	28,479	19,001	21,474
Field operating costs	617	531	382
General and administrative expenses	160	164	134
Depreciation and amortization	211	180	100
Total costs and expenses	29,467	19,876	22,090
OPERATING INCOME	594	518	355
OTHER INCOME/(EXPENSE)			
Equity earnings in unconsolidated entities	14	15	8
Interest expense (net of capitalized interest of $17, $14 and $6, respectively)	(196)	(162)	(86)
Interest income and other income (expense), net	33	10	2
Income before tax	445	381	279
Current income tax expense	(9)	(3)	—
Deferred income tax benefit (expense)	1	(13)	—
Income before cumulative effect of change in accounting principle	437	365	279
Cumulative effect of change in accounting principle	—	—	6
NET INCOME	$ 437	$ 365	$ 285
NET INCOME—LIMITED PARTNERS	$ 325	$ 286	$ 247
NET INCOME—GENERAL PARTNER	$ 112	$ 79	$ 38
BASIC NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.70	$ 2.54	$ 2.84
Cumulative effect of change in accounting principle	—	—	0.07
Net income	$ 2.70	$ 2.54	$ 2.91
DILUTED NET INCOME PER LIMITED PARTNER UNIT			
Income before cumulative effect of change in accounting principle	$ 2.67	$ 2.52	$ 2.81
Cumulative effect of change in accounting principle	—	—	0.07
Net income	$ 2.67	$ 2.52	$ 2.88
BASIC WEIGHTED AVERAGE UNITS OUTSTANDING	120	113	81
DILUTED WEIGHTED AVERAGE UNITS OUTSTANDING	121	114	82

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

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 437	$ 365	$ 285
Adjustments to reconcile to cash flows from operating activities:			
Depreciation and amortization	211	180	100
Cumulative effect of change in accounting principle	—	—	(6)
(Gains)/losses from derivative activities	(141)	24	4
Inventory valuation adjustments	168	1	6
Gain on sale of linefill	(3)	(12)	—
Gain on sale of investment assets	(12)	(4)	—
Equity compensation expense	24	49	43
Deferred income tax (benefit) expense	(1)	13	—
Non-cash amortization of terminated interest rate and foreign currency hedging instruments	—	1	2
Loss on foreign currency revaluation	22	—	4
Equity earnings in unconsolidated entities, net of distributions	(4)	(14)	(7)
Net cash received/(paid) for terminated interest rate and foreign currency hedging instruments	15	—	(2)
Other	2	—	—
Changes in assets and liabilities, net of acquisitions:			
Trade accounts receivable and other	948	(743)	(731)
Inventory	(120)	340	(325)
Accounts payable and other current liabilities	(689)	596	351
Net cash provided by (used in) operating activities	857	796	(276)
CASH FLOWS FROM INVESTING ACTIVITIES			
Cash paid in connection with acquisitions (Note 3)	(709)	(127)	(1,264)
Additions to property, equipment and other	(589)	(548)	(341)
Investment in unconsolidated entities	(37)	(9)	(46)
Net cash paid for linefill in assets owned	(55)	(19)	(4)
Proceeds from sales of assets	51	40	4
Net cash used in investing activities	(1,339)	(663)	(1,651)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net borrowings/(repayments) on revolving credit facilities	286	305	(296)
Net borrowings/(repayments) on short-term letter of credit and hedged inventory facility	(196)	(359)	616
Proceeds from the issuance of senior notes	597	—	1,243
Net proceeds from the issuance of common units (Note 5)	315	383	643
Distributions paid to common unitholders (Note 5)	(418)	(370)	(225)
Distributions paid to general partner (Note 5)	(114)	(81)	(38)
Other financing activities	(6)	(2)	(16)
Net cash provided by (used in) financing activities	464	(124)	1,927
Effect of translation adjustment on cash	5	4	1
Net increase (decrease) in cash and cash equivalents	(13)	13	1
Cash and cash equivalents, beginning of period	24	11	10
Cash and cash equivalents, end of period	$ 11	$ 24	$ 11
Cash paid for interest, net of amounts capitalized	$ 206	$ 186	$ 122
Cash paid for income taxes	$ 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
	Units	Amount	Amount	Amount
Balance at December 31, 2005	**74**	**$1,294**	**$ 37**	**$1,331**
Net income	—	247	38	285
Distributions	—	(225)	(38)	(263)
Issuance of common units in connection with Pacific acquisition	22	1,002	22	1,024
Issuance of common units	13	609	12	621
Other comprehensive loss	—	(21)	—	(21)
Balance at December 31, 2006	**109**	**$2,906**	**$ 71**	**$2,977**
Net income	—	286	79	365
Distributions	—	(370)	(81)	(451)
Issuance of common units	6	375	8	383
Issuance of common units under Long Term Incentive Plans ("LTIP")	1	17	—	17
Class B Units of Plains AAP, L.P. (Note 10)	—	2	1	3
Other comprehensive income	—	127	3	130
Balance at December 31, 2007	**116**	**$3,343**	**$ 81**	**$3,424**
Net income	—	325	112	437
Distributions	—	(418)	(114)	(532)
Issuance of common units	7	309	6	315
Issuance of common units under LTIP	—	1	—	1
Class B Units of Plains AAP, L.P. (Note 10)	—	12	—	12
Other comprehensive loss	—	(103)	(2)	(105)
Balance at December 31, 2008	**123**	**$3,469**	**$ 83**	**$3,552**

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

	Year Ended December 31,		
	2008	2007	2006
		(in millions)	
Net income	$ 437	$365	$285
Other comprehensive income/(loss)	(105)	130	(21)
Comprehensive income	$ 332	$495	$264

CONSOLIDATED STATEMENTS OF CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

	Derivative Instruments	Translation Adjustments	Total
		(in millions)	
Balance at December 31, 2005	$ (16)	$ 87	$ 71
Reclassification adjustments	(144)	—	(144)
Changes in fair value of outstanding hedge positions	142	—	142
Currency translation adjustment	—	(17)	(17)
Deferred losses on settled hedges, net	(2)		(2)
2006 Activity	(4)	(17)	(21)
Balance at December 31, 2006	$ (20)	$ 70	$ 50
Reclassification adjustments	11	—	11
Changes in fair value of outstanding hedge positions	13	—	13
Currency translation adjustment	—	106	106
2007 Activity	24	106	130
Balance at December 31, 2007	$ 4	$ 176	$ 180
Reclassification adjustments	46	—	46
Changes in fair value of outstanding hedge positions	(131)	—	(131)
Deferred gains on settled hedges, net	242	—	242
Currency translation adjustment	—	(262)	(262)
2008 Activity	157	(262)	(105)
Balance at December 31, 2008	$ 161	$ (86)	$ 75

The accompanying notes are an integral part of these 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." Through our 50% equity ownership in PAA/Vulcan Gas Storage, LLC ("PAA/Vulcan"), we are also involved in the development and operation of natural gas storage facilities. We manage our operations through three operating segments: (i) Transportation, (ii) Facilities and (iii) Marketing. See Note 15.

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 17 owners with interests ranging from approximately 50% to less than 1%.

Basis of Consolidation and Presentation

The accompanying financial statements and related notes present our consolidated financial position as of December 31, 2008 and 2007, 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, 2008, 2007 and 2006. All significant intercompany transactions have been eliminated. Certain reclassifications have been made to the previous years to conform to the 2008 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 Accounting Principles Board Opinion No. 18, "The Equity Method of Accounting for Investments in Common Stock" ("APB 18"). 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.

Changes in Accounting Principles

Stock-Based Compensation. In December 2004, Statement of Financial Accounting Standards ("SFAS") No. 123 (revised 2004), "Share-Based Payment" ("SFAS 123(R)") was issued, which amended SFAS No. 123, "Accounting for Stock-Based Compensation," and established accounting for transactions in which an entity exchanges its equity instruments for goods or services. This statement requires that the cost resulting from such share-based payment transactions be recognized in the financial statements at fair value. Following our general partner's adoption of Emerging Issues Task Force Issue No. 04-05, "Determining Whether a General Partner, or the General Partners as a Group,

Note 1—Organization and Basis of Presentation (Continued)

Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights," we are now part of the same consolidated group and thus SFAS 123(R) is applicable to our general partner's long-term incentive plan. We adopted SFAS 123(R) on January 1, 2006 under the modified prospective transition method, as defined in SFAS 123(R), and recognized a gain of approximately $6 million related to the cumulative effect of change in accounting principle. The cumulative effect adjustment represents a decrease to our LTIP life-to-date accrued expense and related liability under our previous cash-plan, probability-based accounting model and adjusts our aggregate liability to the appropriate fair value-based liability as calculated under a SFAS 123(R) methodology. Our LTIPs are administered by our general partner. We are required to reimburse all costs incurred by our general partner related to LTIP settlements. Our LTIP awards are classified as liabilities under SFAS 123(R) as the awards are primarily paid in cash.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the Emerging Issues Task Force ("EITF") issued Issue No. 04-13 ("EITF 04-13"), "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF 04-13 requires that inventory purchase and sale transactions with the same counterparty should be combined for accounting purposes if they were entered into in contemplation of each other. EITF 04-13 includes indicators to be considered for purposes of determining whether such transactions are entered into in contemplation of each other. Guidance was also provided on the circumstances under which nonmonetary exchanges of inventory within the same line of business should be recognized at fair value. EITF 04-13 became effective for reporting periods beginning after March 15, 2006.

We adopted EITF 04-13 on April 1, 2006. The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. In conformity with EITF 04-13, prior periods are not affected, although we have parenthetically disclosed prior period buy/sell transactions in our consolidated statements of operations. The treatment of buy/sell transactions under EITF 04-13 reduces both revenues and purchases and related costs on our income statement but does not impact our financial position, net income or liquidity.

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) accruals related to purchases and sales, (ii) mark-to-market gains and losses pursuant to SFAS No. 133, "Accounting For Derivative Instruments and Hedging Activities," as amended ("SFAS 133"), and SFAS No. 157, "Fair Value Measurements" ("SFAS 157"), (iii) accruals and contingent liabilities, (iv) estimated fair value of assets and liabilities acquired and identification of associated goodwill and intangible assets, (v) accruals related to our equity compensation plans and (vi) property, plant and equipment and depreciation expense. Although we believe these estimates are reasonable, actual results could differ from these estimates.

Note 2—Summary of Significant Accounting Policies (Continued)

Revenue Recognition

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 consist of (i) storage fees from actual storage used on a month-to-month basis; (ii) storage fees resulting from short-term and long-term contracts for committed space that may or may not be utilized by the customer in a given month; and (iii) terminal throughput charges to pump to connecting carriers. Revenues from storage are recognized ratably over the term of the contract. Terminal throughput charges are recognized as the crude oil, LPG or refined product exits the terminal and is delivered to the connecting carrier or third-party terminal. All terminalling and storage revenues are based on actual volumes and rates. 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.

Marketing 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.

The adoption of EITF 04-13 resulted in inventory purchases and sales under buy/sell transactions, which historically would have been recorded gross as purchases and sales, to be treated as inventory exchanges in our consolidated statements of operations. See Note 1 for further discussion.

Purchases and Related Costs

Purchases and related costs include: (i) the cost of crude oil, LPG and refined products purchased in outright purchases as well as buy/sell arrangements prior to the adoption of EITF 04-13; (ii) third-party transportation and storage, whether by pipeline, truck 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.

Note 2—Summary of Significant Accounting Policies (Continued)

Field Operating Costs and General and Administrative Expenses

Field operating costs consist of various field and pipeline operating expenses, including fuel and power costs, telecommunications, payroll and benefit costs (including equity compensation expense) for truck drivers and pipeline field personnel, maintenance 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.

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 within crude oil, refined products and LPG sales and related revenues. The revaluation of foreign currency transactions and monetary assets and liabilities resulted in a loss of approximately $31 million for the year ended December 31, 2008, a gain of less than $1 million for the year ended December 31, 2007 and a loss of approximately $4 million for the year ended December 31, 2006.

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, 2008 and 2007, accounts payable included approximately $44 million and $63 million, respectively, of outstanding checks that were reclassed 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 and refined products. These purchasers include 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 marketing activities that can generally be described as high volume and low margin activities, in many cases involving exchanges of crude oil volumes.

During 2008, the U.S. and world financial markets were extremely volatile and the global economies substantially weakened. In addition, during the first seven months of 2008, the values of crude oil and refined products reached historically high levels, but energy prices dropped precipitously

Note 2—Summary of Significant Accounting Policies (Continued)

during the remainder of the year to much lower levels. This volatility in the financial markets combined with the significant energy price volatility 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.

We have a rigorous credit review process and 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, advance cash payments or "parental" guarantees.

At December 31, 2008 and 2007, we had received approximately $66 million and $57 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, 2008 and 2007, substantially all of our net accounts receivable classified as current assets were less than 60 days past their scheduled invoice date. Our allowance for doubtful accounts receivable totaled $5 million and $1 million at December 31, 2008 and 2007, respectively. Although we consider our allowance for doubtful trade accounts receivable to be adequate, actual amounts could vary significantly from estimated amounts.

Inventory and Pipeline Linefill

Inventory primarily consists of crude oil, LPG and refined products in pipelines, storage tanks and rail cars that is 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, we recorded a non-cash charge of approximately $168 million related to the writedown of our crude oil and LPG inventory due to declines in oil prices during the third and fourth quarters of 2008. During 2007 and 2006, we recorded non-cash charges of approximately $1 million and $6 million, respectively, related to the writedown of such inventory. Linefill and minimum working inventory requirements in assets we own are recorded at historical cost and consist of crude oil and LPG used to pack the pipeline such that when an incremental barrel enters a pipeline it forces a barrel out at another location, as well as the minimum amount of crude oil necessary to operate our storage and terminalling facilities. During 2008 and 2007, we recorded gains of approximately $3 million and $12 million, respectively, on the sale of pipeline linefill for proceeds of approximately $23 million and $20 million, respectively. During 2006, both the gain and applicable proceeds for the sale of pipeline linefill were immaterial.

Minimum working inventory requirements in third-party assets and other working inventory in our assets that is needed for our commercial operations are included in Inventory (a current asset) in determining the average cost of operating inventory. At the end of each period, we reclassify the

Note 2—Summary of Significant Accounting Policies (Continued)

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

	December 31, 2008			December 31, 2007		
	Barrels	Dollars	Dollars/ Barrel[1]	Barrels	Dollars	Dollars/ Barrel[1]
Inventory						
Crude oil	9,986	$ 421	$42.16	7,365	$ 592	$80.38
LPG	7,748	370	$47.75	6,480	363	$56.02
Refined products	103	5	$48.54	133	11	$82.71
Parts and supplies	N/A	5	N/A	N/A	6	N/A
Inventory subtotal	17,837	801		13,978	972	
Long-term inventory						
Crude oil	1,781	121	$67.94	986	64	$64.91
LPG	363	18	$49.59	175	10	$57.14
Long-term inventory subtotal	2,144	139		1,161	74	
Pipeline linefill in owned assets						
Crude oil	9,148	422	$46.13	7,734	282	$36.46
LPG	67	3	$44.78	43	2	$46.51
Pipeline linefill in owned assets subtotal	9,215	425		7,777	284	
Total	29,196	$1,365		22,916	$1,330	

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

Property 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, 2008, 2007 and 2006, capitalized interest was $17 million, $14 million and $6 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 charged to expense as incurred.

Note 2—Summary of Significant Accounting Policies (Continued)

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

	Estimated Useful Lives (Years)	December 31, 2008	December 31, 2007
Crude oil pipelines and facilities	30 - 40	$3,934	$3,603
Crude oil and LPG storage and terminal facilities	30 - 40	944	599
Trucking equipment and other	5 - 40	300	233
Office property and equipment	3 - 5	75	64
Construction in progress	—	474	439
		5,727	4,938
Less accumulated depreciation		(668)	(519)
Property and equipment, net		$5,059	$4,419

Depreciation expense for the years ended December 31, 2008, 2007 and 2006 was $196 million, $160 million and $91 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 (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 PAA/Vulcan, 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 PAA/Vulcan, Frontier, Settoon Towing and Butte are 50%, 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. Distributions to the Partnership will reduce the carrying value of our investments and will be reflected on our cash flow statement 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.

Asset Retirement Obligations

We account for asset retirement obligations under SFAS No. 143, “Accounting for Asset Retirement Obligations” (“SFAS 143”). SFAS 143 establishes accounting requirements for retirement obligations associated with tangible long-lived assets, including estimates related to (1) the time of the liability recognition (“settlement date”), (2) initial measurement of the liability, (3) allocation of asset

Note 2—Summary of Significant Accounting Policies (Continued)

retirement cost to expense, (4) subsequent measurement of the liability and (5) financial statement disclosures. SFAS 143 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.

Many of our pipelines are trunk and interstate systems that transport crude oil and we have determined that the settlement date related to the retirement obligation has an indeterminate life. The pipelines with indeterminate settlement dates have been in existence for many years and with regular maintenance will continue to be in service for many years to come. Also, it is not possible to predict when demands for this transportation 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 and $8 million at December 31, 2008 and 2007, respectively, and decreased primarily as a result of a change in estimates.

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 SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," as amended ("SFAS 144"). Under SFAS 144, 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. In determining the existence of an impairment in carrying value, we make a number of subjective assumptions as to:

- whether there is an indication of impairment;
- the grouping of assets;
- the intention of "holding" versus "selling" an asset;

Note 2—Summary of Significant Accounting Policies (Continued)

- 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 2008, we recognized an impairment of approximately $5 million for the write down of a pipeline that was taken out of service. Impairments of approximately $1 million and less than $1 million were recognized during 2007 and 2006, 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 SFAS No. 142, "Goodwill and Other Intangible Assets" ("SFAS 142") 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. In addition, there is a potential indicator of impairment if a company's market capitalization is less than its book equity. Goodwill is tested for impairment at a level of reporting referred to as a reporting unit. Pursuant to SFAS 142, 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. SFAS 142 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 earnings multiple approach. Multiples of earnings are estimated based on the average multiple of earnings before interest, taxes, depreciation and amortization ("EBITDA") upon which our MLP peers have closed recent acquisitions and which management believes are comparable to our business. 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.

At December 31, 2008, we compared our market capitalization to our book equity to determine if there was an indicator of impairment. Although our market capitalization exceeded the book value of our equity at December 31, 2008, we performed Step 1 of the goodwill impairment test due to the ongoing deterioration of the credit markets and the overall economic conditions. We determined that the fair value was greater than book value for all three reporting units, and therefore goodwill was not considered impaired. We will continue to monitor the market to determine if a triggering event occurs and will perform another goodwill impairment analysis if necessary. Since adoption of SFAS 142, we have not recognized any impairment of goodwill.

Note 2—Summary of Significant Accounting Policies (Continued)

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

	Transportation	Facilities	Marketing	Total
Balance at December 31, 2006	$399	$249	$378	$1,026
2007 Additions				
Pacific[1]	—	30	2	32
Other[2]	5	4	5	14
Balance at December 31, 2007	$404	$283	$385	$1,072
2008 Additions				
Rainbow	194	—	—	194
Other[2]	(36)	—	(20)	(56)
Balance at December 31, 2008	$562	$283	$365	$1,210

(1) Change is due to purchase price adjustments.

(2) Includes goodwill specific to other acquisitions made during 2007, as well as (i) foreign currency translation adjustments, (ii) payment of additional consideration related to an earn-out clause in a prior acquisition and (iii) other immaterial items.

Other assets, net

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

	2008	2007
Debt issue costs	$ 34	$ 28
Fair value of derivative instruments	148	26
Intangible assets	191	124
Other	10	18
	383	196
Less accumulated amortization	(37)	(27)
	$346	$169

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 $7 million and $1 million in 2008 and 2007, respectively.

Amortization expense related to other assets (including finite-lived intangible assets) for each of the three years in the period ended December 31, 2008 was $21 million, $13 million and $9 million, respectively. Our amortization expense for finite-lived intangible assets for the years ended December 31, 2008, 2007 and 2006 was $15 million, $10 million and $5 million, respectively.

Note 2—Summary of Significant Accounting Policies (Continued)

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):

	Estimated Useful Lives (Years)	December 31, 2008			December 31, 2007		
		Cost	Accumulated amortization	Net	Cost	Accumulated amortization	Net
Customer contracts and relationships	4-17	$151	$(24)	$127	$ 84	$(12)	$ 72
Emission reduction credits[1]	N/A	40	—	40	34	—	34
Environmental permits	2	—	—	—	6	(4)	2
		$191	$(24)	$167	$124	$(16)	$108

(1) Emission reduction credits are finite-lived and are subject to amortization from the date that they are first utilized. At December 31, 2008, 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):

2009	$12
2010	10
2011	9
2012	9
2013	9

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 expected future taxes in the jurisdictions in which we operate, (iii) valuation allowances for deferred tax assets and (iv) contingent tax liabilities for estimated exposures related to

Note 2—Summary of Significant Accounting Policies (Continued)

our current tax positions. These estimates depend on assumptions regarding our ability to generate future taxable income during the periods in which temporary differences are deductible.

As of December 31, 2007, we did not record a valuation allowance against our deferred tax assets for federal net operating loss carryforwards. Management believed that it was more likely than not that we would realize the deferred tax assets associated with the federal net operating loss. These net operating losses have since been used to offset taxable income.

Recent Accounting Pronouncements

Standards Adopted as of January 1, 2009

In November 2008, the EITF issued Issue No. 08-06, "Equity Method Investment Accounting Considerations" ("EITF 08-06"). EITF 08-06 addresses certain accounting considerations, including initial measurement, decreases in investment value, and changes in the level of ownership or degree of influence related items related to equity method investments. The provisions of EITF 08-06 will be effective for fiscal years beginning on or after December 15, 2008 and will be applied prospectively. We adopted EITF 08-06 on January 1, 2009 and are currently evaluating the impact of adoption on our consolidated financial statements.

In April 2008, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position ("FSP") No. FAS 142-3 "Determination of the Useful Life of Intangible Assets" ("FSP No. FAS 142-3"). FSP No. FAS 142-3 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 SFAS 142. The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141 (revised 2007), "Business Combinations," and other generally accepted accounting principles. This FSP will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted the FSP on January 1, 2009 and are currently evaluating the impact of adoption on our consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities—an Amendment of FASB Statement No. 133" ("SFAS 161"). SFAS 161 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 SFAS 133, and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 will be effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008. We adopted SFAS 161 on January 1, 2009. Adoption did not have any material impact on our financial position, results of operations or cash flows.

In March 2008, the EITF issued Issue No. 07-04, "Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships" ("EITF 07-04"). EITF 07-04 addresses the application of the two-class method under SFAS No. 128, "Earnings Per Share" 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 dividends

Note 2—Summary of Significant Accounting Policies (Continued)

declared (or accumulated) and participation rights in undistributed earnings. EITF 07-04 will be effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. We adopted EITF 07-04 on January 1, 2009. Adoption will impact the net income available to limited partners used in our computation of EPU but will not impact our distributions to limited partners, financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 160 "Noncontrolling Interests in Consolidated Financial Statements, an amendment of ARB No. 51" ("SFAS 160"). SFAS 160 requires all entities to report noncontrolling (minority) interests in subsidiaries as equity in the consolidated financial statements. The pronouncement 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 SFAS 160 are effective on a prospective basis for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. We adopted SFAS 160 on 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 SFAS No. 141(R) "Business Combinations" ("SFAS 141(R)"). SFAS 141(R) establishes principles and requirements for how an acquirer: (i) recognizes and measures in its financial statements the identifiable assets aquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill aquired 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 SFAS 141(R) will be 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 SFAS 141(R) on January 1, 2009. Adoption will impact our accounting for acquisitions subsequent to that date.

Standards Adopted as of January 1, 2008

In February 2007, the FASB issued SFAS No. 159 "The Fair Value Option for Financial Assets and Financial Liabilities—including an amendment of FAS 115" ("SFAS 159"). SFAS 159 allows entities to choose, at specified election dates, to measure eligible financial assets and liabilities at fair value in situations in which they are not otherwise required to be measured at fair value. If a company elects the fair value option for an eligible item, changes in that item's fair value in subsequent reporting periods must be recognized in current earnings. The provisions of SFAS 159 were effective for fiscal years beginning after November 15, 2007. We adopted SFAS 159 on January 1, 2008, but did not make any elections to value any eligible assets or liabilities at fair value and thus the adoption did not have any impact on our consolidated financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS 157, which defines fair value, establishes a framework for measuring fair value and requires enhanced disclosures regarding fair value measurements. The provisions of SFAS 157 were deferred for one year for certain non-financial assets and non-financial liabilities, including asset retirement obligations, goodwill, intangible assets and long-lived assets. We adopted SFAS 157 as of January 1, 2008 with the exception of those assets and liabilities that are subject to the deferral. The provisions of SFAS 157 are to be applied prospectively and require new disclosures regarding the level of pricing observability associated with financial instruments carried at fair value. See Note 6 for additional disclosure.

Note 2—Summary of Significant Accounting Policies (Continued)

Derivative Instruments and Hedging Activities

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled commodity trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to foreign currency risk. We record all open derivative instruments on the balance sheet as either assets or liabilities measured at their fair value under the provisions of SFAS 133. SFAS 133 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 Accumulated Other Comprehensive Income ("AOCI") and reclassified into earnings when the underlying transaction affects earnings. Accordingly, changes in fair value are included in the current period 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 Unit

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

EITF 03-06 addresses the computation of earnings per share by entities that have issued securities other than common stock that contractually entitle the holder to participate in dividends and earnings of the entity when, and if, it declares dividends on its common stock. Essentially, EITF 03-06 provides that in any accounting period where our aggregate net income exceeds our aggregate distribution for such period, we are required to present earnings per unit as if all of the earnings for the periods were distributed, regardless of the pro forma nature of this allocation and whether those earnings would actually be distributed during a particular period from an economic or practical perspective. EITF 03-06 does not impact our overall net income or other financial results; however, for periods in which aggregate net income exceeds our aggregate distributions for such period, it will have the impact of reducing the earnings per limited partner unit. This result occurs because a larger portion of our aggregate earnings is allocated (as if distributed) to our general partner, even though we make cash distributions on the basis of cash available for distributions, not earnings, in any given accounting period. In accounting periods where aggregate net income does not exceed our aggregate distributions for such period, EITF 03-06 does not have any impact on our earnings per unit calculation.

Effective January 1, 2009, we adopted EITF 07-04 and EITF 03-06 will no longer be applied. See "Recent Accounting Pronouncements" above for further discussion.

Note 2—Summary of Significant Accounting Policies (Continued)

The following sets forth the computation of basic and diluted earnings per limited partner unit under EITF 03-06. The net income available to limited partners and the weighted average limited partner units outstanding have been adjusted for instruments considered common unit equivalents.

	Year Ended December 31,		
	2008	2007	2006
	(amounts in millions, except per unit data)		
Numerator for basic and diluted earnings per limited partner unit:			
Net income	$ 437	$ 365	$ 285
Less: General partner's incentive distribution paid	(106)	(73)	(33)
Subtotal	331	292	252
Less: General partner 2% ownership	(6)	(6)	(5)
Net income available to limited partners	325	286	247
Less: Pro forma EITF 03-06 additional general partner's distribution	—	—	(11)
Net income available to limited partners under EITF 03-06	325	286	236
Less: Limited partner 98% portion of cumulative effect of change in accounting principle	—	—	(6)
Limited partner net income before cumulative effect of change in accounting principle	$ 325	$ 286	$ 230
Denominator:			
Basic weighted average number of limited partner units outstanding	120	113	81
Effect of dilutive securities:			
Weighted average LTIP units[(1)]	1	1	1
Diluted weighted average number of limited partner units outstanding	121	114	82
Basic net income per limited partner unit before cumulative effect of change in accounting principle	$2.70	$2.54	$2.84
Cumulative effect of change in accounting principle per limited partner unit	—	—	0.07
Basic net income per limited partner unit	$2.70	$2.54	$2.91
Diluted net income per limited partner unit before cumulative effect of change in accounting principle	$2.67	$2.52	$2.81
Cumulative effect of change in accounting principle per limited partner unit	—	—	0.07
Diluted net income per limited partner unit	$2.67	$2.52	$2.88

(1) 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. The dilutive securities are reduced by a hypothetical unit repurchase based on the remaining unamortized fair value, as prescribed by the treasury stock method in SFAS 128.

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.

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 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 and has transported approximately 193,000 barrels per day since acquisition. 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 fair value)	26
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	194
Future income tax liability	(110)
Assumption of working capital and other long-term assets and liabilities, including cash[(1)]	(17)
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.

Note 3—Acquisitions and Dispositions (Continued)

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 marketing 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.

2006 Acquisitions

Pacific Energy Partners, L.P. On November 15, 2006 we completed our acquisition of Pacific Energy Partners, L.P. ("Pacific") pursuant to an Agreement and Plan of Merger dated June 11, 2006. The merger-related transactions included: (i) the acquisition from LB Pacific, LP and its affiliates ("LB Pacific") of the general partner interest and incentive distribution rights of Pacific as well as approximately 5 million Pacific common units and approximately 5 million Pacific subordinated units for a total of $700 million and (ii) the acquisition of the balance of Pacific's equity through a unit-for-unit exchange, resulting in the issuance of approximately 22 million Partnership units. The total value of the transaction was approximately $2.5 billion, including the assumption of debt and estimated transaction costs. Upon completion of the merger-related transactions, the general partner and limited partner ownership interests in Pacific were extinguished and Pacific was merged with and into the Partnership (the "Pacific merger"). The assets acquired in the Pacific merger included approximately 4,500 miles of active crude oil pipeline and gathering systems and 550 miles of refined products pipelines, over 13 million barrels of active crude oil and 9 million barrels of refined products storage capacity, a fleet of approximately 75 owned or leased trucks and approximately 2 million barrels of crude oil and refined products linefill and working inventory.

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

Cash payment to LB Pacific	$ 700
Value of Plains common units issued in exchange for Pacific common units[1]	1,002
Assumption of Pacific debt (at fair value)	724
Transaction costs[2]	30
Total purchase price	$2,456

(1) Valued at $45.02, which represents the average closing price of Plains common units two days immediately prior and two days immediately after the merger was announced on June 12, 2006.

(2) Includes investment banking fees, costs associated with a severance plan in conjunction with the acquisition and various other direct acquisition costs.

Note 3—Acquisitions and Dispositions (Continued)

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

Property, plant and equipment, net	$1,385
Investment in Frontier	18
Inventory	34
Pipeline linefill and long-term inventory	66
Intangible assets[1]	69
Goodwill[2][3]	875
Assumption of working capital and other long-term assets and liabilities, including $20 of cash	9
	$2,456

[1] Consists of customer relationships, emissions credits and environmental permits.

[2] Represents the amount in excess of the fair value of the net assets acquired and is associated with our view of the future results of operations of the businesses acquired based on the strategic location of the assets and the growth opportunities that we expect to realize as we integrate these assets into our existing business strategy. See Note 2 for further discussion regarding our goodwill accounting policy.

[3] Includes adjustments recorded during the year ended December 31, 2007, primarily resulting from the final valuation of assets and liabilities acquired.

The majority of the acquisition costs associated with the Pacific merger were incurred as of December 31, 2006, resulting in total cash paid during 2006 of approximately $723 million.

The following table shows our calculation of the sources of funding for the merger (in millions):

Fair value of Plains common units issued in exchange for Pacific common units	$1,002
Plains' general partner capital contribution	22
Assumption of Pacific debt (at fair value), net of repayment of Pacific credit facility[1]	433
Plains new debt incurred	999
Total sources of funding	$2,456

[1] The assumption of Pacific's debt and credit facility at fair value was $433 million and $291 million, respectively. We paid off the credit facility in connection with closing of the transaction.

Other 2006 Acquisitions. During 2006, in addition to the Pacific merger, we completed six additional acquisitions for aggregate consideration of approximately $565 million. These acquisitions included (i) 100% of the equity interests of Andrews Petroleum and Lone Star Trucking, which provide isomerization, fractionation, marketing and transportation services to producers and customers of natural gas liquids (collectively, the "Andrews acquisition"), (ii) crude oil gathering and transportation assets and related contracts in South Louisiana ("SemCrude"), (iii) interests in various crude oil

Note 3—Acquisitions and Dispositions (Continued)

pipeline systems in Canada and the U.S. including a 100% interest in the Bay Marchand-to-Ostrica-to-Alliance ("BOA") Pipeline, 64% interest in the Clovelly-to-Meraux ("CAM") Pipeline system and various interests in the High Island Pipeline System ("HIPS"), and (iv) three refined products pipeline systems from Chevron Pipe Line Company.

The aggregate purchase price of these acquisitions was allocated as follows (in millions):

Inventory	$ 35
Linefill	19
Long-term inventory	2
Property and equipment	327
Goodwill[1]	133
Intangibles[2]	49
Net other assets and liabilities	—
Total Purchase Price	$565

(1) Represents the amount in excess of the fair value of the net assets acquired and is associated with our view of the future results of operations of the businesses acquired based on the strategic location of the assets and the growth opportunities that we expect to realize as we integrate these assets into our existing business strategy. See Note 2 for further discussion regarding our goodwill accounting policy.

(2) Consists of customer relationships.

In addition, in November 2006, we acquired a 50% interest in Settoon Towing for approximately $34 million.

Note 3—Acquisitions and Dispositions (Continued)

Pro Forma Data. The results of operations and assets and liabilities from the Pacific merger have been included in our consolidated financial statements and all three of our segments since November 15, 2006. The following table presents selected unaudited pro forma financial information incorporating the historical (pre-merger) results of Pacific and our other 2006 business combination transactions. The following pro forma information has been prepared as if the Pacific merger and our other business combination transactions in 2006 had been completed on January 1, 2006 as opposed to the actual dates that these acquisitions occurred. The pro forma information is based upon available data and includes certain estimates and assumptions made by management. As a result, this pro forma information is not necessarily indicative of our financial results had the transactions actually occurred on this date. Likewise, the following unaudited pro forma financial information is not necessarily indicative of our future financial results (in millions, except per unit data).

	Year Ended December 31, 2006 (Unaudited)
Revenues	$22,996
Income before cumulative effect of change in accounting principle	$ 309
Net income	$ 316
Basic income before cumulative effect of change in accounting principle per limited partner unit	$ 2.68
Basic net income per limited partner unit	$ 2.74
Diluted income before cumulative effect of change in accounting principle per limited partner unit	$ 2.66
Diluted net income per limited partner unit	$ 2.72

Dispositions

During 2008, 2007 and 2006, we sold various property and equipment for proceeds totaling approximately $12 million, $13 million and $4 million, respectively. A gain of approximately $6 million, a loss of approximately $7 million and a gain of $2 million were recognized in 2008, 2007 and 2006, respectively related to these sales.

Note 4—Debt

Debt consists of the following (in millions):

	December 31, 2008	December 31, 2007
Short-term debt:		
Senior secured hedged inventory facility bearing interest at a rate of 2.3% and 5.3% at December 31, 2008 and 2007, respectively	$ 280	$ 476
Senior unsecured revolving credit facility, bearing interest at a rate of 1.1% and 5.5% at December 31, 2008 and 2007, respectively[1]	746	482
Other	1	2
Total short-term debt	1,027	960
Long-term debt:		
4.75% senior notes due August 2009[2]	175	175
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	250	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	—
6.70% senior notes due May 2036	250	250
6.65% senior notes due January 2037	600	600
Unamortized premium/(discount), net	(6)	(2)
Long-term debt under senior unsecured revolving credit facility and other[1]	40	1
Total long-term debt[1][3]	3,259	2,624
Total debt	$4,286	$3,584

(1) At December 31, 2008 and 2007, we have classified $746 million and $482 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) In August 2009, our $175 million 4.75% senior notes will mature. However, since we have the ability and intent to refinance those notes, they are classified as long-term debt within our balance sheet.

(3) At December 31, 2008, the aggregate fair value of our fixed-rate senior notes was estimated to be approximately $2,700 million. 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

We entered into a new $525 million senior secured hedged inventory facility during November 2008, which matures in November 2009. The new committed facility replaced a $1.2 billion uncommitted facility that was scheduled to mature in November 2008, and also includes an accordion

Note 4—Debt (Continued)

feature which enables us to increase the size of the facility to $1.2 billion, subject to obtaining additional lender commitments. Initial proceeds from the new committed facility were used to refinance the outstanding balance of the previous uncommitted facility and subsequent proceeds will be used to finance purchased or stored hedged inventory. Obligations under the new committed facility are secured by the financed inventory and the associated accounts receivable, and will be repaid from the proceeds of the sale of the financed inventory. The new facility will mature on an annual basis beginning in November 2009 and, except for increased pricing and it being committed, bears similar terms to the previous facility. At December 31, 2008, borrowings of approximately $280 million were outstanding under this facility. At December 31, 2007, borrowings of approximately $476 million were outstanding under our previous $1.2 billion uncommitted hedged inventory facility.

As of December 31, 2008 and 2007, the aggregate borrowing capacity of our senior unsecured revolving credit facility was $1.6 billion and $1.6 billion, respectively (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, 2008 and 2007, amounts outstanding under this facility and together with committed letters of credit were $836 million and $635 million, respectively.

Senior Notes

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. 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 November 2006, in conjunction with the Pacific merger, we assumed two issues of Senior Notes with an aggregate principal balance of $425 million. The $175 million of 6.25% Senior Notes are due September 15, 2015 and the $250 million of 7.125% Senior Notes are due June 15, 2014. Interest payments on the 6.25% Senior Notes are due on March 15 and September 15 of each year, and interest payments on the 7.125% Senior Notes are due on June 15 and December 15 of each year. These notes were recorded at fair value for an aggregate amount of $433 million.

In October 2006, we issued $400 million of 6.125% Senior Notes due 2017 and $600 million of 6.65% Senior Notes due 2037. The notes were sold at 99.56% and 99.17% of face value, respectively. Interest payments are due on January 15 and July 15 of each year. We used the proceeds to fund the cash portion of the merger with Pacific including repayment of amounts outstanding under Pacific's credit facility. Net proceeds in excess of the cash portion of the merger consideration were used to repay amounts outstanding under our credit facilities and for general partnership purposes. In anticipation of the issuance of these notes, we entered into $200 million of notional principal amount U.S. treasury locks to hedge the treasury rate portion of the interest rate on a portion of the notes. The treasury locks were entered into at an interest rate of 4.97%. See Note 6.

During May 2006, we completed the sale of $250 million aggregate principal amount of 6.70% Senior Notes due 2036. The notes were sold at 99.82% of face value. Interest payments are due on May 15 and November 15 of each year. We used the proceeds to repay amounts outstanding under our credit facilities and for general partnership purposes.

Note 4—Debt (Continued)

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 all of our existing 100% owned subsidiaries, except for two subsidiaries with assets regulated by the California Public Utility Commission, and certain other minor subsidiaries. See Note 13 for discussion of our guarantors and non-guarantors.

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. We are in compliance with the covenants contained in our credit agreements and indentures.

Letters of Credit

In connection with our crude oil marketing, 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, 2008 and 2007, we had outstanding letters of credit of approximately $51 million and $153 million, respectively.

Note 4—Debt (Continued)

Maturities

The weighted average life of our long-term debt outstanding at December 31, 2008 was approximately 12 years and the aggregate maturities for the next five years are as follows (in millions):

Calendar Year	Payment
2009	$ 175
2010	—
2011	—
2012	239
2013	250
Thereafter	2,600
Total(1)	$3,264

(1) Excludes aggregate unamortized net discount of $6 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, 2008 consists of 122,911,645 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, generally the general partner is 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").

Upon closing of the Pacific and Rainbow acquisitions, our general partner agreed to reduce the amounts due it as incentive distribution. The total reduction in incentive distributions related to these acquisitions is $75 million. Following the distribution in February 2009, the aggregate remaining incentive distribution reductions related to these acquisitions will be $31 million.

Note 5—Partners' Capital and Distributions (Continued)

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

	Year					
	2008		2007		2006	
	Distribution[1]	Excess over MQD	Distribution[1]	Excess over MQD	Distribution[1]	Excess over MQD
First Quarter	$0.8500	$0.4000	$0.8000	$0.3500	$0.6875	$0.2375
Second Quarter	$0.8650	$0.4150	$0.8125	$0.3625	$0.7075	$0.2575
Third Quarter	$0.8875	$0.4375	$0.8300	$0.3800	$0.7250	$0.2750
Fourth Quarter	$0.8925	$0.4425	$0.8400	$0.3900	$0.7500	$0.3000

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

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

	Distributions Paid				
		General Partner			
Year	Common Units	Incentive	2%	Total	Distributions per limited partner unit
2008	$418	$106	$8	$532	$3.50
2007	$370	$ 73	$8	$451	$3.28
2006	$225	$ 33	$5	$263	$2.87

On January 14 , 2009, we declared a cash distribution of $0.8925 per unit on our outstanding common units. The distribution was paid on February 13, 2009 to unitholders of record on February 3, 2009, for the period October 1, 2008 through December 31, 2008. The total distribution paid was approximately $140 million, with approximately $110 million paid to our common unitholders and $2 million and $28 million paid to our general partner for its general partner and incentive distribution interests, respectively.

Note 5—Partners' Capital and Distributions (Continued)

Equity Offerings

During the three years ended December 31, 2008, we completed the following equity offerings of our common units (in millions, except per unit data):

Period	Units Isssued	Gross Unit Price	Proceeds from Sale	General Partner Contribution	Costs	Net Proceeds[1]
April 2008[2]	6,900,000	$46.31	$320	$ 6	$(11)	$315
2008 Total	**6,900,000**		**$320**	**$ 6**	**$(11)**	**$315**
June 2007[3]	6,296,172	$59.56	$375	$ 8	$ —	$383
2007 Total	**6,296,172**		**$375**	**$ 8**	**$ —**	**$383**
December 2006[3][4]	6,163,960	$48.67	$300	$ 6	$ —	$306
July/August 2006[3][4]	3,720,930	$43.00	160	3	—	163
March/April 2006[3][4]	3,504,672	$42.80	150	3	(1)	152
2006 Total	**13,389,562**		**$610**	**$12**	**$ (1)**	**$621**

(1) Net proceeds for 2006 exclude the common units issued and our general partner's proportionate capital contribution of $22 million pertaining to the equity exchange for the Pacific acquisition.

(2) The April 2008 offering of common units was an underwritten transaction that required us to pay a gross spread.

(3) These offerings were direct placements 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 these transactions.

(4) These offerings involved related parties. See Note 9.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units in Plains AAP, L.P., and authorized the board of directors of Plains All American GP LLC to issue grants. At December 31, 2008, approximately 154,000 Class B units have been granted and the remaining units are reserved for future grants. See Note 10 for further discussion of Class B units.

Note 6—Derivatives and Hedging Instruments

We utilize various derivative instruments to (i) manage our exposure to commodity price risk, (ii) engage in a controlled commodity trading program, (iii) manage our exposure to interest rate risk and (iv) manage our exposure to currency exchange rate risk. Our risk management policies and procedures are designed to monitor interest rates, currency exchange rates, NYMEX, ICE and over-the-counter positions, as well as physical volumes, grades, locations and delivery schedules to help ensure that our hedging activities address our market risks. Our policy is to formally document all

Note 6—Derivatives and Hedging Instruments (Continued)

relationships between hedging instruments and hedged items, as well as our risk management objectives and strategy for undertaking the hedge. We calculate hedge effectiveness on a quarterly basis. 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 that are used in hedging transactions are highly effective in offsetting changes in cash flows or the fair value of hedged items.

Summary of Financial Impact

The majority of our derivative activity is related to our commodity price risk hedging activities. Through these activities, we hedge our exposure to price fluctuations with respect to crude oil, LPG, natural gas and refined products as well as with respect to expected purchases, sales and transportation of these commodities. The instruments 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 revenues in the periods during which the underlying physical transactions occur. Derivatives that do not qualify for hedge accounting and the portion of cash flow hedges that is not highly effective, as defined in SFAS 133, in offsetting changes in cash flows of the hedged items, are marked-to-market in revenues each period. Cash settlements associated with our derivative activities are reflected as operating cash flows in our consolidated statements of cash flows.

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

	December 31,	
	2008	2007
Other current assets	$ 231	$ 56
Other long-term assets	148	26
Other current liabilities	(319)	(97)
Other long-term liabilities and deferred credits	(72)	(22)
Other	—	1
Net Liability	$ (12)	$(36)

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

	December 31, 2008			December 31, 2007		
	Net Asset (Liability)	Earnings	AOCI	Net Asset (Liability)	Earnings	AOCI
Commodity price risk hedging	$(30)	$57	$(87)	$(38)	$(48)	$10
Controlled trading program	—	—	—	—	—	—
Interest rate risk hedging	5	5	—	3	3	—
Currency exchange rate risk hedging	13	(3)	16	(1)	—	(1)
	$(12)	$59	$(71)	$(36)	$(45)	$ 9

Note 6—Derivatives and Hedging Instruments (Continued)

In addition to the net liability related to open derivative positions of $71 million, AOCI also includes deferred gains on settled hedges and other items. The following table summarizes our total net deferred gains in AOCI associated with derivitive instruments (in millions):

	December 31, 2008	December 31, 2007
Deferred gains and (losses) on open hedges	$(71)	$ 9
Deferred gains and (losses) on settled hedges	237	(5)
Reclassification to earnings for open inventory hedges associated with lower-of-cost-or-market adjustments	(5)	—
Total AOCI deferred gain associated with derivitive instruments	$161	$ 4

The total amount of deferred net gain recorded in AOCI is expected to be reclassified to future earnings contemporaneously with (i) the related physical purchase or delivery of the underlying commodity, (ii) interest expense accruals associated with the underlying debt instruments and (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, 2008, a net gain of approximately $67 million will be reclassified to earnings in the next twelve months. Of the remaining deferred gain in AOCI, approximately 83% is expected to be reclassified to earnings prior to 2012 with the remaining deferred gain being reclassed to earnings through 2018. Because a portion of these amounts is based on market prices at the current period end, actual amounts to be reclassified will differ and could vary materially as a result of changes in market conditions.

During the year ended December 31, 2008, and in conjunction with the closing of our Rainbow acquisition, we initially anticipated the sale of 350,000 barrels of crude oil linefill and hedged the commodity price risk associated with the anticipated sale. Upon our determination that the anticipated sale was no longer probable of occurring, we discontinued hedge accounting and reclassed a deferred gain of $17 million from AOCI to crude oil, refined products and LPG sales. During the year ended December 31, 2007, no amounts were reclassified to earnings from AOCI in connection with forecasted transactions that were no longer considered probable of occurring. We recognized a loss in crude oil, refined products and LPG sales of approximately $1 million during each of the years ended December 31, 2008 and December 31, 2007 associated with cash flow hedge ineffectiveness.

We do not enter into master netting agreements with our 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. Our broker receivable was approximately $81 million and $16 million as of December 31, 2008 and December 31, 2007, respectively.

The following sections discuss our risk management activities in the indicated categories.

Commodity Price-Risk Hedging

We use derivative instruments to hedge our exposure to price fluctuations with respect to crude oil, LPG, refined products, and natural gas, and expected purchases, sales and transportation of these commodities. The derivative instruments we use consist primarily of futures, options and swaps traded

Note 6—Derivatives and Hedging Instruments (Continued)

on the NYMEX, ICE and in over-the-counter transactions, including commodity swap and option contracts entered into with financial institutions and other energy companies. In accordance with SFAS 133, these derivative instruments are recognized on the balance sheet at fair value. The instruments 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 sale exclusion and thus are not subject to SFAS 133. Physical transactions that are derivatives and are ineligible, or become ineligible, for the normal purchase and sale treatment (e.g. due to changes in settlement provisions) are recorded on the balance sheet as assets or liabilities at their fair value, with the changes in fair value recorded net in revenues.

Controlled Trading Program

Although we seek to maintain a position that is substantially balanced within our marketing activities, we may experience net unbalanced positions for short periods of time as a result of production, transportation and delivery variances as well as logistical issues associated with inclement weather conditions. 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. In connection with managing these positions and maintaining a constant presence in the marketplace, both necessary for our core business, we engage in a controlled trading program for up to an aggregate of 500,000 barrels of crude oil and a substantially lesser amount for LPG. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. In accordance with SFAS 133, these derivative instruments are recorded in 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

As of December 31, 2008, AOCI includes a total deferred loss of approximately $7 million that relates to terminated interest rate swaps and "treasury locks" (a financial derivative instrument that enables a company to lock in the U.S. Treasury Note rate) that were cash settled in connection with the issuance and refinancing of debt agreements over the past five years. The deferred loss related to these instruments is being amortized to interest expense over the original terms of the forecasted debt instruments.

In November 2006, in conjunction with the Pacific merger, we assumed interest rate swap agreements with an aggregate notional principal amount of $80 million to receive interest at a fixed rate of 7.125% and to pay interest at an average variable rate of six month LIBOR plus 1.67% (set in advance or in arrears depending on the swap transaction). The interest rate swaps mature June 15, 2014 and are callable at the same dates and terms as the 7.125% senior notes. Our counterparties may exercise their call option on June 15, 2009 by paying us $3 million. These swaps were originally entered into to hedge against changes in the fair value of the 7.125% Senior Notes resulting from market fluctuations to LIBOR. Hedge accounting was discontinued on June 30, 2007. The change in fair value of the interest rate swaps is recorded in earnings each period.

Note 6—Derivatives and Hedging Instruments (Continued)

Currency Exchange Rate Risk Hedging

Because a significant portion of our Canadian business is conducted in CAD and, at times, a portion of our debt is denominated in CAD, we use certain financial instruments to minimize the risks of unfavorable changes in exchange rates. These instruments may include forward exchange contracts, swaps and options. At December 31, 2008, our open foreign exchange derivatives consisted of forward exchange contracts that exchange CAD and U.S. dollars on a net basis as follows (in millions):

	CAD	U.S. Dollars	Average Exchange Rate
2009	$43	$38	CAD $1.12 to US $1.00
2010	$25	$25	CAD $1.00 to US $1.00
2011	$25	$25	CAD $1.00 to US $1.00
2012	$25	$25	CAD $1.00 to US $1.00
2013	$19	$19	CAD $1.00 to US $1.00

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

In anticipation of closing the Rainbow acquisition, we entered into a forward currency exchange contract, which exchanged Canadian dollars and US dollars, to hedge the foreign currency exchange risk inherent in the acquisition price. In May 2008, we settled the forward contract, which resulted in a gain of approximately $8 million.

Upon closing of the Rainbow acquisition, we entered into a CAD-denominated intercompany note. In order to hedge the foreign currency exposure on the interest payments, we entered into forward currency exchange contracts. In October 2008, we settled half of these instruments which resulted in a gain of approximately $17 million, which is deferred in AOCI.

Adoption of SFAS 157

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

The 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, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a

Note 6—Derivatives and Hedging Instruments (Continued)

particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the fair value hierarchy levels.

	Fair Value as of December 31, 2008 (in millions)			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivatives	$ 235	$ 9	$ 112	$ 356
Interest rate derivatives	—	—	5	5
Foreign currency derivatives	—	—	18	18
Total assets at fair value	$ 235	$ 9	$ 135	$ 379
Liabilities:				
Commodity derivatives	$ (330)	$ —	$ (56)	$(386)
Foreign currency derivatives	—	—	(5)	(5)
Total liabilities at fair value	$ (330)	$ —	$ (61)	$(391)
Net asset/(liability) at fair value	$ (95)	$ 9	$ 74	$ (12)

The determination of the fair values above incorporates various factors required under SFAS 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit) but also the impact of our nonperformance risk on our liabilities. 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. Fair value adjustments related to counterparty credit risk resulted in a net deferred loss of $1 million in AOCI during the year ended December 31, 2008. There were no changes to any of our valuation techniques during the period.

Level 1

Included within level 1 of the fair value hierarchy are commodity derivatives that are exchange traded. Exchange-traded derivative contracts include futures, 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 is a physical commodity supply contract that meets the definition of a derivative but is not excluded from SFAS 133 under the normal purchase and normal sale scope exception. 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.

Note 6—Derivatives and Hedging Instruments (Continued)

Level 3

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

- 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 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 the derivatives included in level 3 of the fair value hierarchy are classified as level 3 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.

Note 6—Derivatives and Hedging Instruments (Continued)

Rollforward of Level 3 Net Liability

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

	Year Ended December 31, 2008
Balance as of January 1, 2008	$(21)
Realized and unrealized gains (losses):	
Included in earnings[1]	68
Included in other comprehensive income	35
Purchases, issuances, sales and settlements	(8)
Transfers into or out of level 3[2]	—
Balance as of December 31, 2008	$ 74
Change in unrealized gains (losses) included in earnings relating to level 3 derivatives still held as of December 31, 2008[3]	$ 44

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

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

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

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, 2008, 2007 and 2006 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 in the past was 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 delay the effective date of such legislation until 2011 provided that such entities do not exceed the normal growth guidelines. Although we continuously review acquisition opportunities that, if consummated, could cause us to exceed the normal growth guidelines, we believe that we are currently within the normal growth guidelines. At the time of enactment of the legislation in June 2007, we recognized a net deferred income tax liability of approximately $10 million. This amount represented the estimated tax effect of temporary differences that existed at that time and that were expected to reverse after the date that this legislation is effective for us based on the 28% weighted average tax rate that we expect to be in effect when these temporary differences reverse. Substantially all of this amount is related to differences between book basis and tax basis depreciation on applicable property and equipment.

We file Canadian federal and provincial tax returns. Generally, we are no longer subject to Canadian federal and provincial income tax examinations for years before 2005.

Tax Components

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

	Yeare Ended December 31,		
	2008	2007	2006
Current tax expense:			
State income tax	$ 1	$ 1	$—
Canadian federal and provincial income tax	8	2	—
Total current tax expense	$ 9	$ 3	$—
Deferred tax (benefit)/expense:			
State income tax	$—	$ 1	$—
Canadian federal and provincial income tax	(1)	12	—
Total deferred tax (benefit)/expense	$(1)	$13	$—
Total income tax expense	$ 8	$16	$—

Note 7—Income Taxes (Continued)

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,		
	2008	2007	2006
Income before tax	$ 445	$ 381	$ 285
Partnership earnings not subject to current Canadian tax	(422)	(369)	(285)
	$ 23	$ 12	$ —
Canadian federal and provincial corporate tax rate	29.5%	32.1%	32.5%
Income tax at statutory rate	$ 7	$ 4	$ —
Canadian deferred tax as a result of book versus tax differences	4	(2)	—
Canadian permanent differences between book and tax	(3)	—	—
State income tax	1	1	—
Current income tax expense	$ 9	$ 3	$ —
State deferred income tax	—	1	—
Canadian corporation deferred tax as a result of book versus tax differences	(4)	2	—
Flow-through entities deferred tax as a result of book versus tax differences	3	10	—
Deferred income tax (benefit)/expense	$ (1)	$ 13	$ —
Total income tax expense	$ 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,	
	2008	2007
Deferred tax assets:		
Book accruals in excess of current tax deductions	$ 9	$ 5
Net operating losses carried forward	—	4
Total deferred tax assets	9	9
Deferred tax liabilities:		
Canadian partnership income subject to deferral	—	(4)
Property, plant and equipment in excess of tax values	(118)	(29)
Total deferred tax liabilities	(118)	(33)
Net deferred tax liabilities	$(109)	$(24)

We adopted the provisions of FASB Interpretation No. 48, “Accounting for Uncertainty in Income Taxes” (“FIN 48”), an interpretation of SFAS No. 109 “Accounting for Income Taxes,” on January 1, 2007. The adoption of FIN 48 had no material impact on our financial statements. We recognize

Note 7—Income Taxes (Continued)

interest and penalties related to uncertain tax positions in income tax expense. At December 31, 2008 and 2007, we have no material assets, liabilities or accrued interest associated with uncertain tax positions.

Note 8—Major Customers and Concentration of Credit Risk

Marathon Petroleum Company, LLC accounted for 14%, 19% and 14% of our revenues for each of the three years ended December 31, 2008, 2007 and 2006, respectively. Valero Marketing & Supply Company accounted for 10% of our revenues for the year ended December 31, 2007. ConocoPhillips Company accounted for 12% and 11% of our revenues for the years ended December 31, 2008 and 2007, respectively. No other customers accounted for 10% or more of our revenues during any of the three years. The majority of revenues from these customers pertain to our marketing 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.

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, 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, allocable to us (other than expenses related to the Class B units of Plains AAP, L.P.). 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, 2008, 2007 and 2006 were $289 million, $287 million and $205 million, respectively.

Vulcan Energy Corporation

As of December 31, 2008, Vulcan Energy Corporation ("Vulcan Energy") and its affiliates owned approximately 50% of our general partner interest, as well as approximately 10% of our outstanding limited partner units.

Voting Agreement. In August 2005, one of the owners of our general partner notified the remaining owners of its intent to sell its 19% interest in the general partner. The remaining owners elected to exercise their right of first refusal, such that the 19% interest was purchased pro rata by all

Note 9—Related Party Transactions (Continued)

remaining owners. As a result of the transaction, Vulcan Energy's ownership interest 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 1.2% 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

Note 9—Related Party Transactions (Continued)

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. We paid approximately $45 million to Calumet for crude oil purchases in 2006.

Investment in PAA/Vulcan Gas Storage, LLC

PAA/Vulcan, a limited liability company, was formed in 2005. We own 50% of PAA/Vulcan and the other 50% is owned by Vulcan Gas Storage LLC, a subsidiary of Vulcan Capital Private Equity I LLC which is an affiliate of Vulcan Energy. W. Lance Conn, a member of our board of directors, has a profits interest in Vulcan Gas Storage LLC. The Board of Directors of PAA/Vulcan consists of an equal number of our representatives and representatives of Vulcan Gas Storage and is responsible for providing strategic direction and policy-making. We, as the managing member, are responsible for the day-to-day operations. PAA/Vulcan is not a variable interest entity, and we do not have the ability to control the entity; therefore, we account for the investment under the equity method in accordance with APB 18. This investment is reflected in investments in unconsolidated entities in our consolidated balance sheet.

In September 2005, PAA/Vulcan acquired ECI, an indirect subsidiary of Sempra Energy, for approximately $250 million. We and Vulcan Gas Storage LLC each made an initial cash investment of approximately $113 million and Bluewater Natural Gas Holdings, LLC, a subsidiary of PAA/Vulcan ("Bluewater"), entered into a $90 million credit facility contemporaneously with closing. In August 2006, the borrowing capacity under this facility was increased to $120 million.

PAA/Vulcan is developing a natural gas storage facility through its wholly owned subsidiary, Pine Prairie Energy Center, LLC ("Pine Prairie"). Proper functioning of the Pine Prairie storage caverns will require a minimum operating inventory contained in the caverns at all times (referred to as "base gas"). We have arranged to provide the base gas for the storage facility to Pine Prairie at a price not to exceed $8.50 per million cubic feet. In conjunction with this arrangement, we executed hedges on the NYMEX for the relevant delivery periods. At the time of delivery, the base gas will be sold to PAA/Vulcan at the average price that we pay for the base gas (including hedge gains or losses) and we will not recognize any gain or loss. We recorded deferred revenue for receipt of a one-time fee of approximately $1 million for our services to own and manage the hedge positions and to deliver the natural gas.

We and Vulcan Gas Storage are both required to make capital contributions in equal proportions to fund equity requests associated with certain projects specified in the joint venture and other agreements. For certain other specified projects, Vulcan Gas Storage has the right, but not the obligation, to participate for up to 50% of such equity requests. In some cases, Vulcan Gas Storage's obligation is subject to a maximum amount, beyond which Vulcan Gas Storage's participation is optional. For any other capital expenditures, or capital expenditures with respect to which Vulcan Gas

Note 9—Related Party Transactions (Continued)

Storage's participation is optional, if Vulcan Gas Storage elects not to participate, we have the right to make additional capital contributions to fund 100% of the project until our interest in PAA/Vulcan equals 70%. Such contributions would increase our interest in PAA/Vulcan and dilute Vulcan Gas Storage's interest. Once PAA's ownership interest is 70% or more, Vulcan Gas Storage would have the right, but not the obligation, to make future capital contributions proportionate to its ownership interest at the time. During 2008 and 2007, we contributed an additional $37 million and $9 million, respectively, to PAA/Vulcan. During 2008, we received distributions of approximately $7 million from PAA/Vulcan; no such distributions were received during 2007. Vulcan Gas Storage made the same net contribution as we did during 2008 and 2007. Such contributions and distributions did not result in an increase or decrease to our ownership interest. In connection with the construction financing for development of the Pine Prairie storage facility, we and Vulcan Gas Storage have committed to make future aggregate capital contributions up to a maximum of $17.5 million each.

In conjunction with the formation of PAA/Vulcan, PAA and Paul G. Allen provided performance and financial guarantees to the seller with respect to PAA/Vulcan's performance under the purchase agreement, as well as in support of continuing guarantees of the seller with respect to ECI's obligations under certain gas storage and other contracts. PAA and Paul G. Allen would be required to perform under these guarantees only if ECI was unable to perform. In addition, we provided a guarantee under one contract with an indefinite life for which neither Vulcan Capital nor Paul G. Allen provided a guarantee. In exchange for the disproportionate guarantee, PAA will receive preference distributions totaling $1 million over ten years from PAA/Vulcan (distributions that would otherwise have been paid to Vulcan Gas Storage). We believe that the fair value of the obligation to stand ready to perform is minimal. In addition, we believe the probability that we would be required to perform under the guaranty is extremely remote; however, there is no dollar limitation on potential future payments that fall under this obligation.

PAA/Vulcan reimburses us for the allocated costs of PAA's non-officer staff associated with the management and day-to-day operations of PAA/Vulcan and all out-of-pocket costs. In addition, in the first fiscal year that EBITDA (as defined in the PAA/Vulcan LLC agreement) of PAA/Vulcan exceeds $75 million, we will receive a distribution from PAA/Vulcan equal to $6 million per year for each year since formation of the joint venture, subject to a maximum of 5 years or $30 million. Thereafter, we will receive annually a distribution equal to the greater of $2 million per year or two percent of the EBITDA of PAA/Vulcan.

Equity Offerings

In December 2006, we sold 6,163,960 common units, approximately 10% of which were sold to investment funds affiliated with Kayne Anderson Capital Advisors, L.P. ("KACALP") and 10% to EnCap Investments, L.P. In July and August 2006, we sold a total of 3,720,930 common units, approximately 19% and 13% of which were sold to investment funds affiliated with Vulcan Capital and KACALP, respectively. In March and April 2006, we sold 3,504,672 common units, approximately 20% of which were sold to investment funds affiliated with KACALP. KAFU Holdings, L.P. (which is managed by KACALP), an affiliate of EnCap and an affiliate of Vulcan Capital each have a representative on our board of directors.

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 1.4 million "tracking units" which, upon vesting, represent the right to receive a cash payment in an amount based upon the market value of a common unit at the time of vesting. Our general partner will be entitled to reimbursement by us for any costs incurred in settling obligations under the plans.

Under SFAS 123(R) the fair value of our LTIP awards, which are subject to liability classification, is calculated based on the closing market price of our units at each balance sheet date adjusted for (i) the present value of any distributions that are estimated to occur on the underlying units over the vesting period that will not be received by the award recipients and (ii) an estimated forfeiture rate when appropriate. This fair value is recognized as compensation expense over the period the awards are earned. Our LTIP awards typically contain performance conditions based on attainment of certain annualized distribution levels and vest upon the later of a certain date or the attainment of such levels. For awards with performance conditions, we recognize compensation expense only if the achievement of the performance condition is considered probable and amortize that expense over the service period. 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 earlier of a certain date or the attainment of such levels. The DERs terminate with the vesting or forfeiture of the underlying LTIP award. We recognize compensation expense for DER payments in the period the payment is earned.

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

LTIP Units Outstanding	Vesting Distribution Amount	Estimated Unit Vesting Date			
		2009	2010	2011	2012
1.3[1]	$3.20	0.6	0.7	—	—
1.3[2]	$3.50 - $4.50	—	—	0.8	0.5
1.3[3]	$3.50 - $4.00	—	0.8	0.1	0.4
3.9[4][5]		0.6	1.5	0.9	0.9

(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.

Note 10—Equity Compensation Plans (Continued)

(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, these awards will be forfeited. For purposes of this disclosure, the awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(3) These LTIP awards have performance conditions requiring the attainment of an annualized distribution of between $3.50 and $4.00. Fifty percent of these awards will vest in 2012 regardless of whether the performance conditions are attained. For purposes of this disclosure, the awards are presented above assuming the distribution levels are attained and that the awards will vest on the earliest date possible regardless of our current assessment of probability.

(4) Approximately 2.1 million of our approximately 3.9 million outstanding LTIP awards also include DERs, of which 1.2 million are currently earned.

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

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

	Year Ended December 31,					
	2008		2007		2006	
	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit	Units	Weighted Average Grant Date Fair Value per Unit
Outstanding at beginning of period	3.6	$37.75	3.0	$31.94	2.2	$34.37
Granted	0.5	31.79	1.6	47.25	0.9	26.00
Vested	(0.1)	32.44	(0.7)	34.86	—	—
Cancelled or forfeited	(0.1)	36.14	(0.3)	36.00	(0.1)	33.05
Outstanding at end of period	3.9	$36.44	3.6	$37.75	3.0	$31.94

Our accrued liability at December 31, 2008 related to all outstanding LTIP awards and DERs is approximately $55 million, which includes an accrual associated with our assessment that an annualized distribution of $3.75 is probable of occurring. We have not deemed a distribution of more than $3.75 to be probable. At December 31, 2007, the accrued liability was approximately $51 million.

Class B Units of Plains AAP, L.P.

In August 2007, the owners of Plains AAP, L.P. authorized the creation and issuance of up to 200,000 Class B units of Plains AAP, L.P. to be administered by the compensation committee. The Class B units are earned in 25% increments upon us achieving annualized distribution levels of $3.50,

Note 10—Equity Compensation Plans (Continued)

$3.75, $4.00 and $4.50 (or in some cases, within six months thereof). When earned, the Class B units are entitled to participate in distributions paid by Plains AAP, L.P. in excess of $11 million (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. At December 31, 2008 and 2007, 154,000 Class B units were outstanding and 46,000 Class B units were reserved for future grants. In August 2008, 21,000 Class B units were earned upon the payment of our second quarter distribution of $0.8875 per unit and an additional 17,500 were earned in February 2009. 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. The total grant date fair value of the 154,000 Class B units outstanding at December 31, 2008 and 2007 was approximately $34 million of which approximately $13 million and $3 million was recognized as expense during the years ended December 31, 2008 and 2007, respectively.

Other Consolidated 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 vestings (settled both in units and cash) related to the equity compensation plans (in millions):

	Year Ended December 31,		
	2008	2007	2006
Equity compensation expense	$24	$49	$43
LTIP unit vestings	$ 1	$17	$ 1
LTIP cash settled vestings	$ 2	$16	$ 2
DER cash payments	$ 4	$ 4	$ 3

Approximately 0.3 million units were issued in 2007 in connection with the settlement of vested awards. The remaining 0.1 million and 0.4 million of awards that vested during 2008 and 2007, respectively, were settled in cash. There was an insignificant amount of units issued in connection with the settlement of vested awards in 2006. As of December 31, 2008 and 2007, the weighted average remaining contractual life of our outstanding LTIP awards was approximately two years based on expected vesting dates. Based on the December 31, 2008 fair value measurement and probability assessment regarding future distributions, we expect to recognize approximately $41 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 $34.69 at December 31, 2008. Actual amounts may differ materially as a result of a change in the market price of our units and/or

Note 10—Equity Compensation Plans (Continued)

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]
2009	$19
2010	15
2011	5
2012	2
2013	—
Total	$41

(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, 2008.

(2) Includes unamortized fair value associated with Class B units of Plains AAP, L.P.

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-cancellable commitments related to these items at December 31, 2008, are summarized below (in millions):

2009	$ 57
2010	46
2011	40
2012	35
2013	26
Thereafter	204
Total	$408

Expenditures related to leases for 2008, 2007 and 2006 were $82 million, $51 million and $38 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

Note 11—Commitments and Contingencies (Continued)

River. In both cases, emergency response personnel under the supervision of a unified command structure consisting of representatives of Plains, the EPA, the Texas Commission on Environmental Quality and the Texas Railroad Commission conducted clean-up operations at each site. Approximately 980 and 4,200 barrels were recovered from the two respective sites. The unrecovered oil was removed or otherwise addressed by us in the course of site remediation. Aggregate costs associated with the releases, including estimated remediation costs, are estimated to be approximately $4 million to $5 million. In cooperation with the appropriate state and federal environmental authorities, we have completed our work with respect to site restoration, subject to some ongoing remediation at the Pecos River site. 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 Bankruptcy. We will from time to time have claims relating to insolvent suppliers, customers or counterparties, such as the bankruptcy proceedings of SemCrude. 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 $62 million. We intend to vigorously defend our contractual and statutory rights.

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

The People of the State of California v. Pacific Pipeline System, LLC ("PPS"). In March 2005, a release of approximately 3,400 barrels of crude oil occurred on Line 63, subsequently acquired by us in the Pacific merger. The release occurred when 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 connection with this release, in March 2006, PPS, a subsidiary acquired in the Pacific merger, was served with a four-count misdemeanor criminal action in the Los Angeles Superior Court Case No. 6NW01020, which alleged the violation by PPS of two strict liability statutes under the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, and violations of two sections of the California Water Code for the willful and intentional discharge of pollution into state waters. On October 15, 2008 this criminal action (all four counts) was dismissed with prejudice and PPS was not subjected to any fine or penalty.

Note 11—Commitments and Contingencies (Continued)

In September 2008, PPS was served by the State of California with a civil complaint in connection with this release, in the Los Angeles Superior Court Case No. BC398627, alleging violations of the California Fish and Game Code for the unlawful deposit of oil or substances harmful to wildlife into the environment, violations of two sections of the California Water Code for the unlawful discharge of waste into state waters without a permit, and violations of the Public Nuisance Code alleging that discharge of petroleum into waters of the state had created a public nuisance. This case was settled in October 2008. Pursuant to the terms of the settlement agreement, PPS paid no fine or penalty, but made civil settlement payments to various agencies of the State of California in the total amount of approximately $1.1 million.

United States of America v. Pacific Pipeline System, LLC. In September 2008, the EPA filed a civil complaint against PPS 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. CV08-5768DSF(SSX), seeks the maximum permissible penalty under the relevant statutes of approximately $3.7 million. The EPA and DOJ have discretion to reduce the fine, if any, after considering other mitigating factors. Because of the uncertainty associated with these factors, the final amount of the fine that will be assessed for the alleged offenses cannot be ascertained. We may also be subjected to injunctive remedies that would impose additional requirements, costs and constraints on our operations. We will defend against these charges. We believe that several defenses and mitigating circumstances and factors exist that could substantially reduce any penalty or fine that might be imposed by the EPA and DOJ, and intend to pursue discussions with the EPA and DOJ regarding such defenses and mitigating circumstances and factors. Although we have established an estimated loss contingency for this matter, we are presently unable to determine whether the March 2005 spill incident may result in a loss in excess of our accrual for this matter. Discussions with the DOJ on behalf of the EPA to resolve this matter have commenced.

Exxon v. GATX. This Pacific legacy matter 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. The estimated maximum potential remediation cost ranges up to $10 million. Both Exxon and GATX were prior owners of the terminal. We contend that Exxon 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. In a related matter, the New Jersey Department of Environmental Protection has brought suit against GATX and Exxon to recover natural resources damages. Exxon and GATX have filed third-party demands against PAT, seeking indemnity and contribution. We are vigorously defending against any claim that PAT is directly or indirectly liable for damages or costs associated with the contamination.

Other Pacific-Legacy Matters. Pacific had completed a number of acquisitions that had not been fully integrated prior to the merger with Plains. Accordingly, we have and may become aware of other matters involving the assets and operations acquired in the Pacific merger as they relate to compliance with environmental and safety regulations, which matters may result in mitigative costs or the imposition of fines and penalties. We have, for instance, recently settled numerous air permit violations alleged by the Bay Area Air Quality Management District.

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

Note 11—Commitments and Contingencies (Continued)

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 (decrease) the rate of releases from such assets as we implement our procedures, remove selected assets from service and spend capital to upgrade the assets. 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, 2008, our reserve for environmental liabilities totaled approximately $42 million, of which approximately $8 million is classified as short-term and $34 million is classified as long-term. At December 31, 2008, we have recorded receivables totaling approximately $4 million for amounts that are probable of recovery under insurance and from third parties under indemnification agreements.

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

Other. A pipeline, terminal or other facility may experience damage as a result of an accident, natural disaster or terrorist activity. These hazards can cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage and suspension of operations. We maintain insurance of various types that we consider adequate to cover our operations and properties. The insurance covers our assets in amounts considered reasonable. The insurance policies are subject to deductibles that we consider reasonable and not excessive. Our insurance does not cover every potential risk associated with operating pipelines, terminals and other

Note 11—Commitments and Contingencies (Continued)

facilities, including the potential loss of significant revenues. The overall trend in the environmental insurance industry appears to be a contraction in the breadth and depth of available coverage, while costs, deductibles and retention levels have increased. Absent a material favorable change in the environmental insurance markets, this trend is expected to continue as we continue to grow and expand. As a result, we anticipate that we will elect to self-insure more of our environmental activities or incorporate higher retention in our insurance arrangements.

The occurrence of a significant event not fully insured, indemnified or reserved against, or the failure of a party to meet its indemnification obligations, could materially and adversely affect our operations and financial condition. We believe we are adequately insured for public liability and property damage to others with respect to our operations. With respect to all of our coverage, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, although we believe that we have established adequate reserves to the extent that such risks are not insured, costs incurred in excess of these reserves may be higher and may potentially have a material adverse effect on our financial conditions, results of operations or cash flows.

Note 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 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, 2008, we had incurred approximately $9 million of remediation costs associated with these sites, while SOP's share is approximately $5 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

Note 12—Environmental Remediation (Continued)

requiring remediation and developed reserve estimates for the Pacific sites, which total approximately $18 million at December 31, 2008.

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
- "Non-Guarantor Subsidiaries" as of December 31, 2008 include: Pacific Pipeline System, LLC, Pacific Terminals, LLC, Pacific Energy Management LLC, Pacific Energy GP LP, PEG Canada GP LLC and SLC Pipeline LLC. The changes in non-guarantor subsidiaries during the years ended December 31, 2008, 2007 and 2006 were immaterial.

The following supplemental condensed consolidating financial information reflects the Parent's separate accounts, the combined accounts of the Guarantor Subsidiaries, the combined accounts of the Parent's Non-Guarantor Subsidiaries, the combined consolidating adjustments and eliminations and the Parent's consolidated accounts for the dates and periods indicated. For purposes of the following condensed consolidating information, the Parent's investments in its subsidiaries and the Guarantor

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Subsidiaries' investments in their subsidiaries are accounted for under the equity method of accounting (all amounts in millions):

Condensed Consolidating Balance Sheet

	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	3,552	4,198	828	(5,026)	3,552
Total liabilities and partners' capital	$7,113	$9,871	$1,075	$(8,027)	$10,032

	As of December 31, 2007				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
ASSETS					
Total current assets	$2,277	$3,858	$ 91	$(2,553)	$3,673
Property plant and equipment, net	—	3,791	628	—	4,419
Investment in unconsolidated entities	3,881	863	—	(4,529)	215
Other assets	22	1,259	318	—	1,599
Total assets	$6,180	$9,771	$1,037	$(7,082)	$9,906
LIABILITIES AND PARTNERS' CAPITAL					
Total current liabilities	$ 134	$5,911	$ 237	$(2,553)	$3,729
Long-term debt	2,622	2	—	—	2,624
Other long-term liabilities	—	128	1	—	129
Total liabilities	2,756	6,041	238	(2,553)	6,482
Partners' Capital	3,424	3,730	799	(4,529)	3,424
Total liabilities and partners' capital	$6,180	$9,771	$1,037	$(7,082)	$9,906

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Operations

	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)
Interest and other income (expense), net	6	26	1	—	33
Income tax expense	—	(8)	—	—	(8)
Net income (loss)	$ 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)
Interest and other income (expense), net	5	5	—	—	10
Income tax expense	—	(16)	—	—	(16)
Net income (loss)	$ 365	$ 514	$ 61	$(575)	$ 365

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Operations

	Year Ended December 31, 2006				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
Net operating revenues[1]	$ —	$ 955	$16	$ —	$ 971
Field operating costs	—	(376)	(6)	—	(382)
General and administrative expenses	—	(133)	(1)	—	(134)
Depreciation and amortization	(3)	(94)	(3)	—	(100)
Operating income (loss)	(3)	352	6	—	355
Equity earnings in unconsolidated entities	363	14	—	(369)	8
Interest expense	(77)	(9)	—	—	(86)
Interest and other income (expense), net	2	—	—	—	2
Income tax expense	—	—	—	—	—
Income before cumulative effect of change in accounting principle	285	357	6	(369)	279
Cumulative effect of change in accounting principle	—	6	—	—	6
Net income (loss)	$285	$ 363	$ 6	$(369)	$ 285

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

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

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
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	3	187	21	—	211
Inventory valuation adjustment	—	168	—	—	168
(Gains)/losses from derivative activities	—	(141)	—	—	(141)
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)	530	(16)	—	139
Net cash provided by (used in) operating activities	(540)	1,352	45	—	857
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	—	(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	—	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 the 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

Note 13—Supplemental Condensed Consolidating Financial Information (Continued)

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
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	3	157	20	—	180
(Gains)/losses on derivative activities	2	22	—	—	24
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	230	20	(57)	—	193
Net cash provided by operating activities	76	696	24	—	796
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions	—	(127)	—	—	(127)
Additions to property and equipment	—	(524)	(24)	—	(548)
Investment in unconsolidated entities	(9)	—	—	—	(9)
Net cash paid for linefill in assets owned	—	(19)	—	—	(19)
Proceeds from sales of assets	—	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 13—Supplemental Condensed Consolidating Financial Information (Continued)

Condensed Consolidating Statements of Cash Flows

	Year Ended December 31, 2006				
	Parent	Combined Guarantor Subsidiaries	Combined Non-Guarantor Subsidiaries	Eliminations	Consolidated
CASH FLOWS FROM OPERATING ACTIVITIES					
Net income	$ 285	$ 363	$ 6	$(369)	$ 285
Adjustments to reconcile to cash flows from operating activities:					
Depreciation and amortization	3	94	3	—	100
Cumulative effect of change in accounting principle	—	(6)	—	—	(6)
(Gains)/losses on derivative activities	—	4	—	—	4
Inventory valuation adjustment	—	6	—	—	6
Equity compensation expense	—	43	—	—	43
Equity earnings in unconsolidated entities, net of distributions	(362)	(14)	—	369	(7)
Loss on foreign currency revaluation	—	4	—	—	4
Other	—	—	—	—	—
Changes in assets and liabilities, net of acquisitions	(493)	(158)	(8)	(46)	(705)
Net cash provided by (used in) operating activities	(567)	336	1	(46)	(276)
CASH FLOWS FROM INVESTING ACTIVITIES					
Cash paid in connection with acquisitions, net of $20 cash assumed from acquisitions	(704)	(560)	—	—	(1,264)
Additions to property and equipment	—	(340)	(1)	—	(341)
Investment in unconsolidated entities	(46)	(46)	—	46	(46)
Net cash paid for linefill in assets owned	—	(4)	—	—	(4)
Proceeds from sales of assets	—	4	—	—	4
Net cash used in investing activities	(750)	(946)	(1)	46	(1,651)
CASH FLOWS FROM FINANCING ACTIVITIES					
Net repayments on revolving credit facility	(291)	(5)	—	—	(296)
Net borrowings on short-term letter of credit and hedged inventory facility	—	616	—	—	616
Proceeds from the issuance of senior notes	1,243	—	—	—	1,243
Net proceeds from the issuance of common units	643	—	—	—	643
Distributions paid to common unitholders and general partner	(263)	—	—	—	(263)
Other financing activities	(13)	(3)	—	—	(16)
Net cash provided by financing activities	1,319	608	—	—	1,927
Effect of translation adjustment on cash	—	1	—	—	1
Net increase (decrease) in cash and cash equivalents	2	(1)	—	—	1
Cash and cash equivalents, beginning of period	—	10	—	—	10
Cash and cash equivalents, end of period	$ 2	$ 9	$—	$ —	$ 11

Note 14—Quarterly Financial Data (Unaudited):

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total[(1)]
	(in millions, except per unit data)				
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	$ 0.58	$ 0.13	$ 1.15	$ 0.56	$ 2.70
Diluted net income per limited partner unit	$ 0.57	$ 0.13	$ 1.14	$ 0.56	$ 2.67
Cash distributions per common unit[(3)]	$0.8500	$0.8650	$0.8875	$0.8925	$ 3.50
2007					
Revenues	$ 4,230	$ 3,918	$ 5,799	$ 6,447	$20,394
Gross margin[(2)]	164	200	168	150	682
Operating income	118	153	134	114	518
Net income	85	105	98	77	365
Basic net income per limited partner unit	$ 0.62	$ 0.78	$ 0.66	$ 0.48	$ 2.54
Diluted net income per limited partner unit	$ 0.61	$ 0.78	$ 0.66	$ 0.47	$ 2.52
Cash distributions per common unit[(3)]	$0.8000	$0.8125	$0.8300	$0.8400	$ 3.28

(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) Crude oil, refined products and LPG 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) Marketing. Our Chief Operating Decision Maker (our Chief Executive Officer) evaluates segment performance based on a variety of measures including segment profit, segment volumes, segment profit per barrel and maintenance capital investment. We define segment profit as revenues and equity earnings in unconsolidated entities less (i) purchases and related costs, (ii) field operating costs and (iii) segment general and administrative ("G&A") expenses. Each of the items above excludes depreciation and amortization. As a master limited partnership, we make quarterly distributions of our "available cash" (as defined in our partnership agreement) to our unitholders. We look at each period's earnings before non-cash depreciation and amortization as an important measure of segment performance. The exclusion of depreciation and amortization expense could be viewed as limiting the usefulness of segment profit as a performance measure because it does not account in current periods for the implied reduction in value of our capital assets, such as crude oil pipelines and facilities, caused by aging and wear and tear. We compensate for this limitation by recognizing that depreciation and amortization are largely offset by repair and maintenance investments, which 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

Note 15—Operating Segments (Continued)

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	Marketing	Total
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
Net gains/(losses) related to inventory valuation adjustments and derivative activities[2]	$ —	$ —	$ (4)	$ (4)
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[5]	$3,127	$1,754	$ 5,025	$ 9,906
Net gains/(losses) related to inventory valuation adjustments and derivative activities[2]	$ —	$ —	$ (27)	$ (27)
Maintenance capital	$ 34	$ 10	$ 6	$ 50
Twelve Months Ended December 31, 2006				
Revenues:				
External Customers (includes buy/sell revenues of $0, $0, and $4,762, respectively)	$ 344	$ 41	$22,060	$22,445
Intersegment[1]	190	47	1	238
Total revenues of reportable segments	$ 534	$ 88	$22,061	$22,683
Equity in earnings of unconsolidated entities	$ 2	$ 6	$ —	$ 8
Segment profit[2][3][4]	$ 200	$ 35	$ 228	$ 463
Capital expenditures	$1,957	$1,323	$ 73	$ 3,353
Total assets[5]	$1,917	$1,348	$ 5,450	$ 8,715
Net gains/(losses) related to inventory valuation adjustments and derivative activities[2]	$ —	$ —	$ (4)	$ (4)
Maintenance capital	$ 20	$ 5	$ 3	$ 28

(1) Intersegment sales are conducted at posted tariff rates, rates similar to those charged to third parties or rates that we believe approximate market rates.

Note 15—Operating Segments (Continued)

(2) Gains/losses from derivative activities are included in marketing revenues and impact segment profit. The gain within the marketing segment for the year ended December 31, 2008 excludes a gain of $3 million related to foreign currency and interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit. The loss for the year ended December 31, 2007 includes a $2 million gain related to interest rate derivatives, which is included in interest income and other income (expense), net, but does not impact segment profit.

(3) Marketing segment profit includes interest expense on contango inventory purchases of $21 million, $44 million and $49 million for the years ended December 31, 2008, 2007 and 2006, respectively.

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

	Year ended December 31,		
	2008	2007	2006
Segment profit	$ 819	$ 713	$ 463
Depreciation and amortization	(211)	(180)	(100)
Interest expense	(196)	(162)	(86)
Interest income and other income (expense), net	33	10	2
Income tax expense	(8)	(16)	—
Income before cumulative effect of change in accounting principle	$ 437	$ 365	$ 279
Cumulative effect of change in accounting priciple	—	—	6
Net income	$ 437	$ 365	$ 285

(5) Certain reclassifications have been made to the balances as of December 31, 2007 and 2006 to conform to the current year presentation of intercompany balances to more accurately reflect total assets by segment.

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):

	For the Year Ended December 31,		
Revenues(1)(2)	2008	2007	2006
United States (includes buy/sell revenues of $4,170 for 2006)	$25,183	$16,843	$18,772
Canada (includes buy/sell revenues of $592 for 2006)	4,878	3,551	3,673
	$30,061	$20,394	$22,445

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

(2) Certain reclassifications have been made to the revenues for the years ended December 31, 2007 and 2006 to conform to the current year presentation of intercompany revenues to more accurately reflect revenues attributable to the respective geographic areas.

	As of December 31,	
Long-Lived Assets(1)	2008	2007
United States	$5,976	$5,407
Canada	1,312	800
	$7,288	$6,207

(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	—	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).
3.8	—	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).
3.9	—	Fourth Amended and Restated Limited Liability Company Agreement of Plains All American GP LLC dated August 7, 2008 (incorporated by reference to Exhibit 3.2 to the Current Report on Form 8-K filed August 7, 2008).
3.10	—	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).
3.11	—	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).
3.12	—	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).
3.13	—	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	—	Third Supplemental Indenture (Series A and Series B 4.75% Senior Notes due 2009) 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 4.4 to the Registration Statement on Form S-4, File No. 333-121168).
4.5	—	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).
4.6	—	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).
4.7	—	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).
4.8	—	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).
4.9	—	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).
4.10	—	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).

4.11 — 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).

4.12 — 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).

4.13 — 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).

4.14 — 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).

4.15 — 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).

4.16 — Indenture dated June 16, 2004 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 7⅛% senior notes due 2014 (incorporated by reference to Exhibit 4.21 to Pacific Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2004).

4.17 — First Supplemental Indenture dated March 3, 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 (incorporated by reference to Exhibit 4.1 to Pacific Energy Partners, L.P.'s Current Report on Form 8-K filed March 9, 2005).

4.18 — Second Supplemental 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 (incorporated by reference to Exhibit 4.17 to the Annual Report on Form 10-K for the year ended December 31, 2006).

4.19 — Third 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 4.2 to the Current Report on Form 8-K filed November 21, 2006).

4.20 — Fourth 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 4.23 to the Annual Report on Form 10-K for the year ended December 31, 2007).

4.21†	—	Fifth Supplemental Indenture dated December 17, 2008 among Plains All American Pipeline, L.P., PAA Finance Corp., the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee.
4.22	—	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 6¼% 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).
4.23	—	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).
4.24	—	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).
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	—	Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 1.1 to the Current Report on Form 8-K filed September 19, 2005).
10.31	—	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).
10.32**	—	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).
10.33**	—	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).
10.34	—	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).
10.35	—	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).
10.36**	—	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).
10.37**	—	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).

10.38	—	First Amendment dated May 9, 2006 to the Amended and Restated Limited Liability Company Agreement of PAA/Vulcan Gas Storage, LLC dated September 13, 2005 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed May 15, 2006).
10.39**	—	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).
10.40**	—	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).
10.41**	—	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).
10.42	—	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).
10.43**	—	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).
10.44**	—	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).
10.45	—	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).
10.46	—	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).
10.47	—	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).
10.48	—	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).
10.49**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Greg L. Armstrong.
10.50**†	—	First Amendment to Amended and Restated Employment Agreement dated December 4, 2008 between Plains All American GP LLC and Harry N. Pefanis.
10.51**†	—	First Amendment to Plains All American GP LLC 2005 Long-Term Incentive Plan dated December 4, 2008.
10.52**†	—	Second Amendment to Plains All American GP LLC 1998 Long-Term Incentive Plan dated December 4, 2008.

10.53**†	—	Form of Amendment to LTIP grant letters dated December 4, 2008 (executive officers).
10.54**†	—	Form of Amendment to LTIP grant letters (directors).
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

† Filed herewith

** Management compensatory plan or arrangement