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

FORM 8-K

CURRENT REPORT

**Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934**

Date of Report (Date of earliest event reported): September 15, 2010

ENERGY TRANSFER EQUITY, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	**1-32740**	**30-0108820**
(State or other jurisdiction of incorporation)	**(Commission File Number)**	**(IRS Employer Identification Number)**

3738 Oak Lawn Avenue
Dallas, TX 75219
(Address of principal executive offices)

(214) 981-0700
(Registrant's telephone number, including area code)

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

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

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

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

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

Item 8.01. Other Events.

Energy Transfer Equity, L.P. (the “Partnership”) is filing, for each of Energy Transfer Partners, L.P. (“ETP”), Energy Transfer Partners GP, L.P. (“ETP GP”) and Energy Transfer Partners, L.L.C. (“ETP LLC”), the following financial statements and related footnotes: (i) the audited consolidated financial statements as of December 31, 2009 and 2008, and for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007 and (ii) the unaudited interim condensed consolidated financial statements as of June 30, 2010, and for the three and six months ended June 30, 2010 and 2009. The consolidated financial statements of ETP are included as Exhibits 99.1 and 99.2 to this Current Report on Form 8-K and incorporated herein by reference. The consolidated financial statements of ETP GP are included as Exhibits 99.3 and 99.4 to this Current Report on Form 8-K and incorporated herein by reference. The consolidated financial statements of ETP LLC are included as Exhibits 99.5 and 99.6 to this Current Report and incorporated herein by reference.

The Partnership owns a 100% membership interest in ETP LLC. ETP LLC is the sole general partner of ETP GP, which in turn is the general partner of ETP.

The Partnership is also filing, for each of Regency Energy Partners LP (“Regency”) and Regency GP LP (“Regency GP LP”), the following financial statements and related footnotes: (i) the audited consolidated financial statements as of December 31, 2009 and 2008, and for each of the years in the three-year period ended December 31, 2009 and (ii) the unaudited interim condensed consolidated financial statements as of June 30, 2010, and for the periods from April 1, 2010 to May 25, 2010 and May 26, 2010 to June 30, 2010, for the periods from January 1, 2010 to May 25, 2010 and May 26, 2010 to June 30, 2010, and for the three and six months ended June 30, 2009. The consolidated financial statements of Regency are included as Exhibits 99.7 and 99.8 to this Current Report on Form 8-K and incorporated herein by reference. The consolidated financial statements of Regency GP LP are included as Exhibits 99.9 and 99.10 to this Current Report on Form 8-K and incorporated herein by reference.

The Partnership indirectly owns the sole general partner of Regency GP LP, which in turn is the general partner of Regency.

Item 9.01. Financial Statements and Exhibits.

(d) **Exhibits.**

Exhibit Number	Description of the Exhibits
Exhibit 23.1	Consent of Grant Thornton LLP
Exhibit 23.2	Consent of KPMG LLP
Exhibit 99.1	Audited consolidated financial statements of Energy Transfer Partners, L.P. and subsidiaries.
Exhibit 99.2	Unaudited interim condensed consolidated financial statements of Energy Transfer Partners, L.P. and subsidiaries.
Exhibit 99.3	Audited consolidated financial statements of Energy Transfer Partners GP, L.P. and subsidiaries.
Exhibit 99.4	Unaudited interim condensed consolidated financial statements of Energy Transfer Partners GP, L.P. and subsidiaries.
Exhibit 99.5	Audited consolidated financial statements of Energy Transfer Partners, L.L.C. and subsidiaries.
Exhibit 99.6	Unaudited interim condensed consolidated financial statements of Energy Transfer Partners, L.L.C. and subsidiaries.
Exhibit 99.7	Audited consolidated financial statements of Regency Energy Partners LP and subsidiaries.
Exhibit 99.8	Unaudited interim condensed consolidated financial statements of Regency Energy Partners LP and subsidiaries.
Exhibit 99.9	Audited consolidated financial statements of Regency GP LP and subsidiaries.
Exhibit 99.10	Unaudited interim condensed consolidated financial statements of Regency GP LP and subsidiaries.

SIGNATURES

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

Energy Transfer Equity, L.P.

By: LE GP, LLC,
its general partner

Date: September 15, 2010

/S/ JOHN W. MCREYNOLDS

John W. McReynolds
President and Chief Financial Officer

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated February 24, 2010, with respect to the consolidated financial statements of Energy Transfer Partners, L.P. and subsidiaries as of December 31, 2009 and 2008 and for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007, and our reports dated August 9, 2010, with respect to the consolidated financial statements of Energy Transfer Partners GP, L.P. and subsidiaries as of December 31, 2009 and 2008 and for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007, and the consolidated financial statements of Energy Transfer Partners, L.L.C. and subsidiaries as of December 31, 2009 and 2008 and for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007, all included in this Current Report of Energy Transfer Equity, L.P. on Form 8-K. We hereby consent to the incorporation by reference of said reports in the Registration Statements of Energy Transfer Equity, L.P. on Forms S-3 (File No. 333-164414 and File No. 333-146300) and on Form S-8 (File No. 333-146298).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
September 14, 2010

Exhibit 23.2

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners
Energy Transfer Equity, L.P.:

We consent to the inclusion in registration statements No. 333-164414 and No. 333-146300 on Form S-3 and No. 333-146298 on Form S-8 of Energy Transfer Equity, L.P. of our reports dated March 1, 2010 with respect to the consolidated balance sheets of Regency Energy Partners LP as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009 and management's assessment of internal control over financial reporting as of December 31, 2009, and of our report dated September 13, 2010 with respect to the consolidated balance sheets of Regency GP LP as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009, which reports appear herein the Form 8-K of Energy Transfer Equity, L.P. filed September 15, 2010.

/s/ KPMG LLP

Dallas, Texas
September 15, 2010

Report of Independent Registered Public Accounting Firm

Partners
Energy Transfer Partners, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, partners' capital, and cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Partners, L.P. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Partnership retrospectively adopted a new accounting pronouncement on January 1, 2009 related to the calculation of earnings per unit.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Energy Transfer Partners, L.P.'s internal control over financial reporting as of December 31, 2009, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) and our report dated February 24, 2010 (not separately included herein), expressed an unqualified opinion on the effectiveness of internal control over financial reporting.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
February 24, 2010

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 68,183	$ 91,902
Marketable securities	6,055	5,915
Accounts receivable, net of allowance for doubtful accounts	566,522	591,257
Accounts receivable from related companies	57,369	17,895
Inventories	389,954	272,348
Exchanges receivable	23,136	45,209
Price risk management assets	12,371	5,423
Other current assets	148,373	153,452
Total current assets	1,271,963	1,183,401
PROPERTY, PLANT AND EQUIPMENT, net	8,670,247	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	663,298	10,110
GOODWILL	745,505	743,694
INTANGIBLES AND OTHER ASSETS, net	383,959	394,199
Total assets	$ 11,734,972	$ 10,627,489

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 358,997	$ 381,135
Accounts payable to related companies	38,842	34,547
Exchanges payable	19,203	54,636
Price risk management liabilities	442	94,978
Interest payable	136,222	106,259
Accrued and other current liabilities	228,946	433,794
Current maturities of long-term debt	40,887	45,198
Total current liabilities	823,539	1,150,547
LONG-TERM DEBT, less current maturities	6,176,918	5,618,549
DEFERRED INCOME TAXES	112,997	100,597
OTHER NON-CURRENT LIABILITIES	21,810	14,727
COMMITMENTS AND CONTINGENCIES (Note 10)		
	7,135,264	6,884,420
PARTNERS' CAPITAL:		
General Partner	174,884	161,159
Limited Partners:		
Common Unitholders (179,274,747 and 152,102,471 units authorized, issued and outstanding at December 31, 2009 and 2008, respectively)	4,418,017	3,578,997
Class E Unitholders (8,853,832 units authorized, issued and outstanding - held by subsidiary and reported as treasury units)	-	-
Accumulated other comprehensive income	6,807	2,913
Total partners' capital	4,599,708	3,743,069
Total liabilities and partners' capital	$ 11,734,972	$ 10,627,489

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
		As Adjusted (Note 2)	As Adjusted (Note 2)	As Adjusted (Note 2)
REVENUES:				
Natural gas operations	$ 4,115,806	$ 7,653,156	$ 1,832,192	$ 5,385,892
Retail propane	1,190,524	1,514,599	471,494	1,179,073
Other	110,965	126,113	45,824	227,072
Total revenues	5,417,295	9,293,868	2,349,510	6,792,037
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	2,519,575	5,885,982	1,343,237	4,207,700
Cost of products sold - retail propane	574,854	1,014,068	315,698	734,204
Cost of products sold - other	27,627	38,030	14,719	136,302
Operating expenses	680,893	781,831	221,757	559,600
Depreciation and amortization	312,803	262,151	71,333	179,162
Selling, general and administrative	173,936	194,227	59,132	145,417
Total costs and expenses	4,289,688	8,176,289	2,025,876	5,962,385
OPERATING INCOME	1,127,607	1,117,579	323,634	829,652
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(394,274)	(265,701)	(66,298)	(175,563)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	(1,013)	31,032
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	2,157	9,306	(5,202)	2,019
INCOME BEFORE INCOME TAX EXPENSE	804,319	872,703	272,613	690,939
Income tax expense	12,777	6,680	10,789	13,658
NET INCOME	791,542	866,023	261,824	677,281
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	-	-	-	1,142
NET INCOME ATTRIBUTABLE TO PARTNERS	791,542	866,023	261,824	676,139
GENERAL PARTNER'S INTEREST IN NET INCOME	365,362	315,896	91,011	235,876
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 426,180	$ 550,127	$ 170,813	$ 440,263
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 2.53	$ 3.74	$ 1.24	$ 3.32
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	167,337,192	146,871,261	137,624,934	132,618,053
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 2.53	$ 3.74	$ 1.24	$ 3.31
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	167,768,981	147,090,608	138,013,366	132,877,152

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income	$ 791,542	$ 866,023	$ 261,824	$ 677,281
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(10,211)	(34,901)	(17,269)	(160,420)
Change in value of derivative instruments accounted for as cash flow hedges	3,182	17,326	21,626	175,720
Change in value of available-for-sale securities	10,923	(6,418)	(98)	280
	3,894	(23,993)	4,259	15,580
Comprehensive income	795,436	842,030	266,083	692,861
Less: Comprehensive income attributable to noncontrolling interest	-	-	-	1,142
Comprehensive income attributable to partners	$ 795,436	$ 842,030	$ 266,083	$ 691,719

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL
(Dollars in thousands)

	General Partner	Limited Partners: Common Unitholders	Limited Partners: Class G Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, August 31, 2006	$ 82,450	$ 1,647,345	$ -	$ 7,067	$ 1,857	$ 1,738,719
Distributions to partners	(215,770)	(366,180)	(40,598)	-	-	(622,548)
Issuance of Class G Units to Energy Transfer Equity, LP	-	-	1,200,000	-	-	1,200,000
Conversion to Common Units	-	1,208,394	(1,208,394)	-	-	-
Capital contribution from General Partner	24,490	-	-	-	-	24,490
Tax effect of remedial income allocation from tax amortization of goodwill	-	(1,161)	-	-	-	(1,161)
Non-cash unit-based compensation expense	-	10,471	-	-	-	10,471
Other comprehensive income, net of tax	-	-	-	15,580	-	15,580
Other	-	-	-	-	(760)	(760)
Net income	235,876	391,271	48,992	-	1,142	677,281
Balance, August 31, 2007	127,046	2,890,140	-	22,647	2,239	3,042,072
Distributions to partners	(62,897)	(113,080)	-	-	-	(175,977)
Issuance of units in acquisitions	-	1,400	-	-	-	1,400
Issuance of units in public offering	-	234,887	-	-	-	234,887
Capital contribution from General Partner	5,009	-	-	-	-	5,009
Tax effect of remedial income allocation from tax amortization of goodwill	-	(1,161)	-	-	-	(1,161)
Units returned by employees for tax withholdings	-	(164)	-	-	-	(164)
Non-cash executive compensation	24	1,143	-	-	-	1,167
Non-cash unit-based compensation expense	-	8,114	-	-	-	8,114
Other comprehensive income, net of tax	-	-	-	4,259	-	4,259
Sale of noncontrolling interest and other	-	-	-	-	(2,239)	(2,239)
Net income	91,011	170,813	-	-	-	261,824
Balance, December 31, 2007	160,193	3,192,092	-	26,906	-	3,379,191
Distributions to partners	(322,923)	(556,295)	-	-	-	(879,218)
Issuance of units in acquisitions	-	2,228	-	-	-	2,228
Issuance of units in public offering	-	373,059	-	-	-	373,059
Capital contribution from General Partner	7,968	-	-	-	-	7,968
Tax effect of remedial income allocation from tax amortization of goodwill	-	(3,407)	-	-	-	(3,407)
Units returned by employees for tax withholdings	-	(3,513)	-	-	-	(3,513)
Non-cash executive compensation	25	1,225	-	-	-	1,250
Non-cash unit-based compensation expense	-	23,481	-	-	-	23,481
Other comprehensive income, net of tax	-	-	-	(23,993)	-	(23,993)
Net income	315,896	550,127	-	-	-	866,023
Balance, December 31, 2008	161,159	3,578,997	-	2,913	-	3,743,069
Distributions to partners	(355,016)	(602,239)	-	-	-	(957,255)
Issuance of units in acquisitions	-	63,339	-	-	-	63,339
Issuance of units in public offerings	-	936,337	-	-	-	936,337
Capital contributions from General Partner	12,286	-	-	-	-	12,286
Contributions receivable from General Partner	(8,932)	-	-	-	-	(8,932)
Distributions on unvested unit awards	-	(2,673)	-	-	-	(2,673)
Tax effect of remedial income allocation					-	
from tax amortization of goodwill	-	(3,762)	-	-	-	(3,762)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	-	20,613	-	-	-	20,613
Non-cash executive compensation	25	1,225	-	-	-	1,250
Other comprehensive income loss, net of tax	-	-	-	3,894	-	3,894
Net income	365,362	426,180	-	-	-	791,542
Balance, December 31, 2009	$ 174,884	$ 4,418,017	$ -	$ 6,807	$ -	$ 4,599,708

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 791,542	$ 866,023	$ 261,824	$ 677,281
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	312,803	262,151	71,333	179,162
Amortization of finance costs charged to interest	8,645	5,886	1,435	4,061
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Goodwill impairment	-	11,359	-	-
Non-cash unit-based compensation expense	24,032	23,481	8,114	10,471
Non-cash executive compensation expense	1,250	1,250	442	-
Deferred income taxes	11,966	(5,280)	1,003	(4,042)
(Gains) losses on disposal of assets	1,564	1,303	(14,310)	6,310
Distributions on unvested awards	(2,673)	-	-	-
Distributions in excess of (less than) equity in earnings of affiliates, net	3,224	5,621	4,448	(5,161)
Other non-cash	(4,468)	3,382	(2,069)	(761)
Net change in operating assets and liabilities, net of effects of acquisitions	(323,999)	74,954	(87,062)	241,182
Net cash provided by operating activities	826,878	1,258,145	245,702	1,112,732
CASH FLOWS FROM INVESTING ACTIVITIES:				
Net cash (paid for) received in acquisitions	30,367	(84,783)	(337,092)	(90,695)
Capital expenditures	(748,621)	(2,054,806)	(651,228)	(1,107,127)
Contributions in aid of construction costs	6,453	50,050	3,493	10,463
(Advances to) repayments from affiliates, net	(655,500)	54,534	(32,594)	(993,866)
Proceeds from the sale of assets	21,545	19,420	21,478	23,135
Net cash used in investing activities	(1,345,756)	(2,015,585)	(995,943)	(2,158,090)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	3,475,107	6,015,461	1,741,547	4,757,971
Principal payments on debt	(2,954,737)	(4,699,123)	(1,062,272)	(4,260,494)
Net proceeds from issuance of Limited Partner Units	936,337	373,059	234,887	1,200,000
Capital contribution from General Partner	3,354	7,968	29	24,490
Distributions to partners	(957,255)	(879,218)	(175,977)	(622,548)
Debt issuance costs	(7,647)	(25,272)	(211)	(11,397)
Net cash provided by financing activities	495,159	792,875	738,003	1,088,022
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(23,719)	35,435	(12,238)	42,664
CASH AND CASH EQUIVALENTS, beginning of period	91,902	56,467	68,705	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 68,183	$ 91,902	$ 56,467	$ 68,705

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Tabular dollar amounts in thousands, except per unit data)

1. OPERATIONS AND ORGANIZATION:

Financial Statement Presentation

The consolidated financial statements of Energy Transfer Partners, L.P. and subsidiaries (the “Partnership” or “ETP”) presented herein for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) and pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”). We consolidate all majority-owned subsidiaries. We present equity and net income attributable to noncontrolling interest for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through February 24, 2010, the date the financial statements were originally issued.

We are managed by our general partner, Energy Transfer Partners GP, L.P. (our “General Partner” or “ETP GP”), which is in turn managed by its general partner, Energy Transfer Partners, L.L.C. (“ETP LLC”). Energy Transfer Equity, L.P., a publicly traded master limited partnership (“ETE”), owns ETP LLC, the general partner of our General Partner.

The consolidated financial statements of the Partnership presented herein include our operating subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“ETC OLP”); Energy Transfer Interstate Holdings, LLC (“ET Interstate”), the parent company of Transwestern Pipeline Company, LLC (“Transwestern”) and ETC Midcontinent Express Pipeline, LLC (“ETC MEP”); ETC Fayetteville Express Pipeline, LLC (“ETC FEP”); ETC Tiger Pipeline, LLC (“ETC Tiger”); Heritage Operating, L.P. (“HOLP”); Heritage Holdings, Inc. (“HHI”); and Titan Energy Partners, L.P. (“Titan”). The operations of ET Interstate are included since the date of the Transwestern acquisition on December 1, 2006. ETC FEP and ETC Tiger are included since their inception dates on August 27, 2008 and June 20, 2008, respectively. The operations of all other subsidiaries listed above are reflected for all periods presented.

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

In November 2007, we changed our fiscal year end to the calendar year. Thus, a new fiscal year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007.

We did not recast the financial data for the prior fiscal periods because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the years ended December 31, 2009 and 2008 are substantially similar to what is reflected in the information for the year ended August 31, 2007.

Certain prior period amounts have been reclassified to conform to the 2009 presentation. Other than the reclassifications related to the adoption of Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51*, which is now incorporated into ASC 810-10-65 (see Note 2), these reclassifications had no impact on net income or total equity.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the “Operating Companies”) as follows:

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, Arizona, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- ET Interstate, the parent company of Transwestern and ETC MEP, both of which are Delaware limited liability companies engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- HOLP, a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan, a Delaware limited partnership also engaged in retail propane operations.

The Partnership, the Operating Companies and their subsidiaries are collectively referred to in this report as “we,” “us,” “ETP,” “Energy Transfer” or the “Partnership.”

ETC OLP owns an interest in and operates approximately 14,800 miles of in service natural gas gathering and intrastate transportation pipelines, three natural gas processing plants, eleven natural gas treating facilities, eleven natural gas conditioning facilities and three natural gas storage facilities located in Texas.

Revenue in our intrastate transportation and storage operations is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The intrastate transportation and storage operations also consist of the HPL System, which generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System also transports natural gas for a variety of third party customers. Our intrastate transportation and storage segment also generates revenues from fees charged for storing customers' working natural gas in our storage facilities. In addition, the use of the Bammel storage facility allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin.

Our interstate transportation operations principally focus on natural gas transportation of Transwestern, which owns and operates approximately 2,700 miles of interstate natural gas pipeline, with an additional 180 miles under construction, extending from Texas through the San Juan Basin to the California border. In addition, we have interests in joint ventures that have 500 miles of interstate natural gas pipeline and 185 miles under construction. Transwestern is a major natural gas transporter to the California border and delivers natural gas from the east end of its system to Texas intrastate and Midwest markets. The Transwestern pipeline interconnects with our existing intrastate pipelines in West Texas. The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

Revenue in our midstream operations is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines (excluding the interstate transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

Our retail propane segment sells propane and propane-related products and services. The HOLP and Titan customer base includes residential, commercial, industrial and agricultural customers.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month's financial results for the midstream and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2009 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition

Revenues for sales of natural gas, NGLs including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

Our intrastate transportation and storage and interstate transportation segments' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

Our intrastate transportation and storage segment also generates revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from the midstream segment's marketing operations, and from producers at the wellhead.

In addition, our intrastate transportation and storage segment generates revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from the midstream segment are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in our midstream segment, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

We conduct marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

We have a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

Regulatory Accounting - Regulatory Assets and Liabilities

Transwestern, part of our interstate transportation segment, is subject to regulation by certain state and federal authorities and has accounting policies that conform to Statement of Financial Accounting Standards No. 71 (As Amended), *Accounting for the Effects of Certain Types of Regulation*, now incorporated into ASC 980, which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

As a result of our acquisition of a natural gas compression equipment business in exchange for ETP Common Units, cash acquired in connection with acquisitions during 2009 exceeded the cash we paid by $30.4 million.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Accounts receivable	$ 28,431	$ 220,635	$ (169,263)	$ 54,347
Accounts receivable from related companies	(29,042)	6,849	(12,557)	(6,003)
Inventories	(101,592)	96,145	(168,430)	196,173
Exchanges receivable	22,074	(7,888)	(4,216)	(3,406)
Other current assets	8,155	(57,041)	(4,701)	53,597
Intangibles and other assets	(4,836)	(40,802)	605	(1,867)
Accounts payable	(16,024)	(296,185)	195,644	(92,172)
Accounts payable to related companies	4,459	(13,957)	29,012	18,564
Exchanges payable	(35,433)	14,254	6,117	3,000
Accrued and other current liabilities	(123,362)	32,377	977	(27,458)
Interest payable	29,963	42,952	33,408	14,844
Other long-term liabilities	1,401	1,741	(680)	1,460
Price risk management liabilities, net	(108,193)	75,874	7,022	30,103
Net change in assets and liabilities, net of effect of acquisitions	$ (323,999)	$ 74,954	$ (87,062)	$ 241,182

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NON-CASH INVESTING ACTIVITIES:				
Transfer of investment in affiliate in purchase of Transwestern (Note 3)	$ -	$ -	$ -	$ 956,348
Investment in Calpine Corporation received in exchange for accounts receivable	$ -	$ 10,816	$ -	$ -
Capital expenditures accrued	$ 46,134	$ 153,230	$ 87,622	$ 43,498
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 26,237	$ 5,077	$ 3,896	$ 533,625
Issuance of common units in connection with certain acquisitions	$ 63,339	$ 2,228	$ 1,400	$ -
Capital contribution receivable from General Partner	$ 8,932	$ -	$ -	$ -
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$ 367,924	$ 237,620	$ 51,465	$ 184,993
Cash paid for income taxes	$ 15,447	$ 4,674	$ 9,009	$ 8,583

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reflected as current assets on the consolidated balance sheets at fair value.

During the year ended December 31, 2008, we determined there was an other-than-temporary decline in the market value of one of our available-for-sale securities, and reclassified into earnings a loss of $1.4 million, which is recorded in other expense. Unrealized holding gains (losses), net of tax, of $7.4 million, $(6.4) million, $(0.1) million, and $0.3 million were recorded through accumulated other comprehensive income ("AOCI"), based on the market value of the securities, for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively. The change in value of our available-for-sale securities for the year ended December 31, 2009 includes realized losses of $3.5 million reclassified from AOCI during the period as discussed in "Accounts Receivable" below.

Accounts Receivable

Our midstream and intrastate transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. Management believes that the occurrence of bad debt in our midstream and intrastate transportation and storage segments was not significant at December 31, 2009 or 2008; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage segments was not deemed necessary.

Our interstate transportation operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Transwestern's management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Transwestern establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. Transwestern considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

Our propane operations grant credit to their customers for the purchase of propane and propane-related products. Included in accounts receivable are trade accounts receivable arising from HOLP's retail and wholesale propane and Titan's retail propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane operations are recorded as amounts are billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the propane segment is based on management's assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

We enter into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

We exchanged a portion of our outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation ("Calpine") common stock valued at $10.8 million during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock is included in marketable securities on the consolidated balance sheet at a fair value of $4.8 million as of December 31, 2008. In 2009, we sold the stock for $7.3 million and recorded a realized loss of $3.6 million, of which $3.5 million was reclassified from AOCI to other income in the consolidated statement of operations.

Accounts receivable consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas operations	$ 429,849	$ 444,816
Propane	143,011	155,191
Less - allowance for doubtful accounts	(6,338)	(8,750)
Total, net	$ 566,522	$ 591,257

The activity in the allowance for doubtful accounts consisted of the following:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Balance, beginning of period	$ 8,750	$ 5,698	$ 5,601	$ 4,000
Accounts receivable written off, net of recoveries	(5,404)	(4,963)	(447)	(2,628)
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Balance, end of period	$ 6,338	$ 8,750	$ 5,698	$ 5,601

Inventories

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 157,103	$ 184,727
Propane	66,686	63,967
Appliances, parts and fittings and other	166,165	23,654
Total inventories	$ 389,954	$ 272,348

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheet and have been recorded in cost of products sold in our consolidated statements of operations.

During 2009, we recorded lower of cost or market adjustments of $54.0 million, which were offset by fair value adjustments related to our application of fair value hedging, of $66.1 million.

During 2008, we recorded lower-of-cost-or-market adjustments of $69.5 million for natural gas inventory and $4.4 million for propane inventory to reflect market values, which were less than the weighted-average cost. The natural gas inventory adjustment in 2008 was partially offset in net income by the recognition of unrealized gains on related cash flow hedges in the amount of $21.7 million from AOCI.

Exchanges

The midstream and intrastate transportation and storage segments' exchanges consist of natural gas and NGL delivery imbalances with others. These amounts, which are valued at market prices, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheets. Management believes market value approximates cost.

The interstate transportation segment's natural gas imbalances occur as a result of differences in volumes of gas received and delivered. Transwestern records natural gas imbalances for in-kind receivables and payables at the dollar weighted composite average of all current month gas transactions and dollar valued imbalances are recorded at contractual prices.

Other Current Assets

Other current assets consisted of the following:

	December 31, 2009	December 31, 2008
Deposits paid to vendors	$ 79,694	$ 78,237
Prepaid and other	68,679	75,215
Total other current assets	$ 148,373	$ 153,452

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or Federal Energy Regulatory Commission ("FERC") mandated lives of the assets. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the installation of company-owned propane tanks and construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our results of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of long-lived assets was required during the periods presented.

Capitalized interest is included for pipeline construction projects, except for interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of our revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2009	December 31, 2008
Land and improvements	$ 87,224	$ 74,731
Buildings and improvements (10 to 40 years)	156,676	129,714
Pipelines and equipment (10 to 83 years)	6,933,189	5,136,357
Natural gas storage (40 years)	100,746	92,457
Bulk storage, equipment and facilities (3 to 83 years)	591,908	533,621
Tanks and other equipment (10 to 30 years)	602,915	578,118
Vehicles (3 to 10 years)	176,946	156,486
Right of way (20 to 83 years)	509,173	358,669
Furniture and fixtures (3 to 10 years)	32,810	28,075
Linepack	53,404	48,108
Pad gas	47,363	53,583
Other (5 to 10 years)	117,896	97,975
	9,410,250	7,287,894
Less – Accumulated depreciation	(979,158)	(700,826)
	8,431,092	6,587,068
Plus – Construction work-in-process	239,155	1,709,017
Property, plant and equipment, net	$ 8,670,247	$ 8,296,085

We recognized the following amounts of depreciation expense, capitalized interest, and AFUDC for the periods presented:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Depreciation expense	$ 291,908	$ 244,689	$ 64,569	$ 163,630
Capitalized interest, excluding AFUDC	$ 11,791	$ 21,595	$ 12,657	$ 22,979
AFUDC (both debt and equity components)	$ 10,237	$ 50,074	$ 5,095	$ 3,600

Advances to and Investment in Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we have a 20% to 50% ownership and exercise significant influence over, but do not control the investee's operating and financial policies.

We account for our investments in Midcontinent Express Pipeline LLC and Fayetteville Express Pipeline LLC using the equity method. See Note 4 for a discussion of these joint ventures.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of December 31 for subsidiaries in our interstate segment and as of August 31 for all others. At December 31, 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No other goodwill impairments were recorded for the periods presented in these consolidated financial statements. Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation	Midstream	Retail Propane	All Other	Total
Balance, December 31, 2007	$ 10,327	$ 98,613	$ 24,368	$ 594,801	$ -	$ 728,109
Purchase accounting adjustments	-	-	-	2,457	-	2,457
Goodwill acquired	-	-	9,141	15,346	-	24,487
Goodwill Impairment	-	-	(11,359)	-	-	(11,359)
Balance, December 31, 2008	10,327	98,613	22,150	612,604	-	743,694
Purchase accounting adjustments	-	-	-	(8,662)	-	(8,662)
Goodwill acquired	-	-	-	33	10,440	10,473
Balance December 31, 2009	$ 10,327	$ 98,613	$ 22,150	$ 603,975	$ 10,440	$ 745,505

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

Intangibles and Other Assets

Intangibles and other assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other assets were as follows:

	December 31, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (3 to 15 years)	$ 24,139	$ (12,415)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,843	(53,123)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(5,638)	23,015	(3,744)
Patents (9 years)	750	(35)	-	-
Other (10 years)	478	(397)	2,677	(2,244)
Total amortizable intangible assets	202,225	(71,608)	210,330	(70,092)
Non-amortizable intangible assets - Trademarks	75,825	-	75,667	-
Total intangible assets	278,050	(71,608)	285,997	(70,092)
Other assets:				
Financing costs (3 to 30 years)	68,597	(24,774)	59,108	(16,586)
Regulatory assets	101,879	(9,501)	98,560	(5,941)
Other	41,316	-	43,153	-
Total intangibles and other long-term assets	$ 489,842	$ (105,883)	$ 486,818	$ (92,619)

Aggregate amortization expense of intangible and other assets are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Reported in depreciation and amortization	$ 20,895	$ 17,462	$ 6,764	$ 15,532
Reported in interest expense	$ 8,188	$ 6,008	$ 1,710	$ 4,502

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2010	$ 26,991
2011	25,326
2012	21,740
2013	16,310
2014	15,343

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate segment and as of August 31 for all others. No impairment of intangible assets was required during the periods presented in these consolidated financial statements.

Asset Retirement Obligation

We record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, we also recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

We have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates. However, management was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2009 or 2008 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2009	December 31, 2008
Customer advances and deposits	$ 88,430	$ 106,679
Accrued capital expenditures	46,134	153,230
Accrued wages and benefits	25,202	64,692
Taxes other than income taxes	23,294	20,772
Income taxes payable	3,401	14,538
Deferred income taxes	-	589
Other	42,485	73,294
Total accrued and other current liabilities	$ 228,946	$ 433,794

Customer Advances and Deposits

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Fair Value of Financial Instruments

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at December 31, 2009 was $6.75 billion and $6.22 billion, respectively. At December 31, 2008, the aggregate fair value and carrying amount of long-term debt was $5.10 billion and $5.66 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. We currently do not have any fair value measurements that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations.

The following table summarizes the fair value of our financial assets and liabilities as of December 31, 2009 and 2008 based on inputs used to derive their fair values:

	Fair Value Measurements at December 31, 2009 Using			Fair Value Measurements at December 31, 2008 Using		
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets:						
Marketable securities	$ 6,055	$ 6,055	$ -	$ 5,915	$ 5,915	$ -
Natural gas inventories	156,156	156,156	-	-	-	-
Commodity derivatives	32,479	20,090	12,389	111,513	106,090	5,423
Liabilities:						
Commodity derivatives	(8,016)	(7,574)	(442)	(43,336)	-	(43,336)
Interest rate swap derivatives	-	-	-	(51,642)	-	(51,642)
	$ 186,674	$ 174,727	$ 11,947	$ 22,450	$ 112,005	$ (89,555)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized. In March 2008, we received a reimbursement related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million, which is recorded in other income on our consolidated statement of operations for the year ended December 31, 2008.

Contributions in aid of construction costs were as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Received and netted against project costs	$ 6,453	$ 50,050	$ 3,493	$ 10,463
Recorded in other income	(305)	8,352	216	403
Totals	$ 6,148	$ 58,402	$ 3,709	$ 10,866

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and totaled $55.9 million and $112.0 million for the years ended December 31, 2009 and 2008, respectively, $30.7 million for the four months ended December 31, 2007 and $58.6 million for the year ended August 31, 2007. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis.

Income Taxes

Energy Transfer Partners, L.P. is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities, in addition to the allocation requirements related to taxable income under the Second Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement").

Our partnership will be considered to have terminated for federal income tax purposes if transfers of units within a 12-month period constitute the sale or exchange of 50% or more of our capital and profits interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of our capital and profits interests within the prior 12-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

We exceeded the 50% threshold on May 7, 2007, and, as a result, our partnership terminated for federal tax income purposes on that date. This termination did not affect our classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of our “qualifying income” for federal income tax purposes. This termination required us to close our taxable year, make new elections as to various tax matters and reset the depreciation schedule for our depreciable assets for federal income tax purposes. The resetting of our depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to our Unitholders. However, certain elections we made in connection with this tax termination allowed us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of our Unitholders, which deductions had not previously been utilized in computing taxable income allocable to our Unitholders.

As a result of the tax termination discussed above, we elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our subsidiary, Heritage Holdings, Inc. (“HHI”), which owns our Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of our Common Units. The amount of such “goodwill” accumulated as of the date of our acquisition of HHI (approximately $158.0 million) is now being amortized over 15 years beginning on May 7, 2007, the date of our new tax elections. We account for HHI using the treasury stock method due to its ownership of our Class E units. We account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of our HHI purchase price allocation, which effectively results in a charge to our common equity and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the years ended December 31, 2009 and 2008, the four months ended December, 31, 2007, and the year ended August 31, 2007, this resulted in a current tax expense and deferred tax benefit (with a corresponding charge to common equity as an adjustment of the purchase price allocation) of approximately $3.8 million, $3.4 million, $1.2 million and $1.2 million, respectively. As of December 31, 2009, the amount of tax goodwill to be amortized over the next 13 years for which HHI will receive a remedial income allocation is approximately $132.8 million.

As a limited partnership, we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries (“C corporations”). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, our non-qualifying income did not exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes, under which deferred income taxes are recorded based upon differences between the financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

Accounting for Derivative Instruments and Hedging Activities

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage segment to hedge the sales price of retention gas and hedge location price differentials related to the transportation of natural gas.
- Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We are exposed to market risk for changes in interest rates related to our revolving credit facilities. We previously have managed a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not accounted for as cash flow hedges are classified in other income. See Note 12 for additional information related to interest rate derivatives.

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 7). Normal allocations according to percentage interests are made after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner.

Unit-Based Compensation

We recognize compensation expense for equity awards issued to employees over the vesting period based on the grant-date fair value. The grant-date fair value is determined based on the market price of our Common Units on the grant date, adjusted to reflect the present value of any expected distributions that will not accrue to the employee during the vesting period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected distributions based on the most recently declared distributions as of the grant date.

New Accounting Standards

A retrospective adjustment has been made to prior period income per limited partner unit presented in our consolidated statements of operations to conform to current period presentation as discussed further below.

Accounting Standards Codification. On July 1, 2009, the Financial Accounting Standards Board ("FASB") instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The *FASB Accounting Standards Codification*™ ("ASC") is now the single authoritative source for GAAP. Although the implementation of ASC has no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Noncontrolling Interests. On January 1, 2009, we adopted SFAS 160, now incorporated into ASC 810-10, which established new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, the new standard requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent's equity. The amount of new income attributable to the noncontrolling interest is included in consolidated net income on the face of the income statement. The new standard clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, the new standard requires that a parent recognizes a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss is measured using the fair value of the noncontrolling equity investment on the deconsolidation date. This standard also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. The adoption of this standard did not have a significant impact on our financial position or results of operations. However, it did result in certain changes to our financial position presentation.

Upon adoption, we reclassified $1.1 million of minority interest expense to net income attributable to noncontrolling interest in our consolidated statements of operations for the year ended August 31, 2007. Net income per limited partner unit has not been affected as a result of the adoption of this standard.

Earnings per Unit. On January 1, 2009, we adopted a new methodology for calculating earnings per unit to reflect recently ratified changes to accounting standards. This new standard was originally issued as Emerging Issues Task Force Issue No. 07-4, *Application of the Two-Class Method under FASB Statement No. 128 to Master Limited Partnerships*, and is now incorporated into ASC 260-10.

Based on the terms of our Partnership Agreement, the new methodology requires us to allocate any excess undistributed earnings to the general partner and limited partners based on their respective ownership interests, with none of the excess undistributed earnings allocated to the incentive distribution rights ("IDRs"). Previously, we allocated a portion of the excess undistributed earnings to the IDRs. Thus, for periods where earnings exceed distributions, the new methodology will result in a higher income per limited partner unit than our previous approach. For periods where distributions exceed earnings, the new methodology is consistent with our previous approach.

On January 1, 2009, we also adopted FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which is now incorporated into ASC 260-10-45. This standard clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently, awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. Based on unvested unit awards outstanding at the time of adoption, application of this standard did not have a material impact on our computation of earnings per unit.

The following financial table sets forth the effect of the retrospective application of the new methodology under ASC 260-10-55 and ASC 260-10-45:

	Year Ended December 31, 2008		Four Months Ended December 31, 2007		Year Ended August 31, 2007	
	Originally Reported	As Adjusted	Originally Reported	As Adjusted	Originally Reported	As Adjusted
Basic net income per limited partner unit	$ 3.75	$ 3.74	$ 1.22	$ 1.24	$ 3.32	$ 3.32
Diluted net income per limited partner unit	$ 3.74	$ 3.74	$ 1.21	$ 1.24	$ 3.31	$ 3.31

Business Combinations. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations*, which is now incorporated into ASC 805. The new standard significantly changes the accounting for business combinations and includes a substantial number of new disclosure requirements. The new standard requires an acquiring entity to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions and changes the accounting treatment for certain specific items, including:

Ÿ Acquisition costs are generally expensed as incurred;

Ÿ Noncontrolling interests (previously referred to as “minority interests”) are valued at fair value at the acquisition date;

Ÿ In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;

Ÿ Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and

Ÿ Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

Our adoption of this standard did not have an immediate impact on our financial position or results of operations; however, it has impacted the accounting for our business combinations subsequent to adoption.

Derivative Instruments and Hedging Activities. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133*, which is now incorporated into ASC 815. This standard changed the disclosure requirements for derivative instruments and hedging activities, including requirements for qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The standard only affected disclosure requirements; therefore, our adoption did not impact our financial position or results of operations.

Equity Method Investment Accounting. On January 1, 2009, we adopted Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations*, which is now incorporated into ASC 323-10. This standard establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment, and also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. Our adoption did not have a material impact on our financial position or results of operations.

Subsequent Events. During 2009, we adopted Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events*, which is now incorporated into ASC 855. Under this standard, we are required to evaluate subsequent events through the date that our financial statements are issued and also required to disclose the date through which subsequent events are evaluated. The adoption of this standard does not change our current practices with respect to evaluating, recording and disclosing subsequent events; therefore, our adoption of this statement during the second quarter had no impact on our financial position or results of operations.

3. ACQUISITIONS:

Proposed Transaction

We have agreed to purchase a natural gas gathering company which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale. The purchase price is $150 million in cash, excluding certain adjustments as defined in the purchase agreement, and the acquisition is expected to close in March 2010.

2009

In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas, in exchange for our issuance of 1,450,076 Common Units having an aggregate market value of approximately $63.3 million on the closing date. In connection with this transaction, we received cash of $41.1 million, assumed total liabilities of $30.5 million, which includes $8.4 million in notes payable and recorded goodwill of $8.7 million. In addition, we acquired ETG in August 2009. See Note 14.

2008

During the year ended December 31, 2008, HOLP and Titan collectively acquired substantially all of the assets of 20 propane businesses. The aggregate purchase price for these acquisitions totaled $96.4 million, which included $76.2 million of cash paid, net of cash acquired, liabilities assumed of $8.2 million, 53,893 Common Units issued valued at $2.2 million and debt forgiveness of $9.8 million. The cash paid for acquisitions was financed primarily with ETP’s and HOLP’s Senior Revolving Credit Facilities. We recorded $15.3 million of goodwill in connection with these acquisitions.

Transition Period 2007

Canyon Acquisition

In October 2007, we acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the “Canyon acquisition”) for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The purchase price was initially allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. We completed the purchase price allocation during the third quarter of 2008. The adjustments to the purchase price allocation were not material. The final allocations of the purchase price are noted below:

Accounts receivable	$ 3,613
Inventory	183
Prepaid and other current assets	1,606
Property, plant, and equipment	284,910
Intangibles and other assets	6,351
Goodwill	11,359
Total assets acquired	308,022
Accounts payable	(1,840)
Customer advances and deposits	(1,030)
Total liabilities assumed	(2,870)
Net assets acquired	$ 305,152

2007

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (“GE”) and Southern Union Company (“Southern Union”), we acquired the member interests in CCE Holdings, LLC (“CCEH”) from GE and certain other investors for $1.00 billion. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to ETE simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP’s 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern, which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and formed our interstate transportation segment.

The total acquisition cost for Transwestern, net of cash acquired, was as follows:

Basis of investment in CCEH at November 30, 2006	$ 956,348
Distributions received on December 1, 2006	(6,217)
Fair value of short-term debt assumed	13,000
Fair value of long-term debt assumed	519,377
Other assumed long-term indebtedness	10,096
Current liabilities assumed	35,781
Cash acquired	(3,386)
Acquisition costs incurred	11,696
Total	$ 1,536,695

In September 2006, we acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of $30.6 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas and are included in our midstream operating segment. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility. In March 2008, a contingent payment of $8.7 million was recorded as an adjustment to goodwill in the midstream segment.

In December 2006, we purchased a natural gas gathering system in north Texas for $32.0 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $21.0 million to be determined two years after the closing date. In December 2008, it was determined that a contingency payment would not be required. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility.

During the fiscal year ended August 31, 2007, HOLP and Titan collectively acquired substantially all of the assets of five propane businesses. The aggregate purchase price for these acquisitions totaled $17.6 million, which included $15.5 million of cash paid, net of cash acquired, and liabilities assumed of $2.1 million. The cash paid for acquisitions was financed primarily with ETP’s and HOLP’s Senior Revolving Credit Facilities.

Except for the acquisition of the 50% member interests in CCEH, our acquisitions were accounted for under the purchase method of accounting and the purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. The acquisition of 100% of Transwestern has been accounted for under the purchase method of accounting since the acquisition on December 1, 2006.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for the fiscal year 2007 acquisitions described above, net of cash acquired:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$ -	$ 20,062	$ 1,111
Inventory	-	895	414
Prepaid and other current assets	-	11,842	57
Investment in unconsolidated affiliate	(503)	-	-
Property, plant, and equipment	50,916	1,254,968	8,035
Intangibles and other assets	23,015	141,378	3,808
Goodwill	-	107,550	4,167
Total assets acquired	73,428	1,536,695	17,592
Accounts payable	-	(1,932)	(381)
Customer advances and deposits	-	(700)	(254)
Accrued and other current liabilities	(292)	(33,149)	(170)
Short-term debt (paid in December 2006)	-	(13,000)	-
Long-term debt	-	(519,377)	(1,309)
Other long-term obligations	-	(10,096)	-
Total liabilities assumed	(292)	(578,254)	(2,114)
Net assets acquired	$ 73,136	$ 958,441	$ 15,478

The purchase price for the acquisitions was initially allocated based on the estimated fair value of the assets acquired and liabilities assumed. The Transwestern allocation was based on the preliminary results of independent appraisals. The purchase price allocations were completed during the first quarter of 2008. The final allocation adjustments were not significant.

Included in the property, plant and equipment associated with the Transwestern acquisition is an aggregate plant acquisition adjustment of $446.2 million, which represents costs allocated to Transwestern’s transmission plant. This amount has not been included in the determination of tariff rates Transwestern charges to its regulated customers. The unamortized balance of this adjustment was $419.6 million at December 31, 2008 and is being amortized over 35 years, the composite weighted average estimated remaining life of Transwestern’s assets as of the acquisition date.

Regulatory assets, included in intangible and other assets on the consolidated balance sheet, established in the Transwestern purchase price allocation consist of the following:

Accumulated reserve adjustment	$ 42,132
AFUDC gross-up	9,280
Environmental reserves	6,623
South Georgia deferred tax receivable	2,593
Other	9,329
Total Regulatory Assets acquired	$ 69,957

All of Transwestern’s regulatory assets are considered probable of recovery in rates.

We recorded the following intangible assets and goodwill in conjunction with the fiscal year 2007 acquisitions described above:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Intangible assets:			
Contract rights and customer lists (6 to 15 years)	$ 23,015	$ 47,582	$ -
Financing costs (7 to 9 years)	-	13,410	-
Other	-	-	3,808
Total intangible assets	23,015	60,992	3,808
Goodwill	-	107,550	4,167
Total intangible assets and goodwill acquired	$ 23,015	$ 168,542	$ 7,975

Goodwill was warranted because these acquisitions enhance our current operations, and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible. We do not believe that the acquired intangible assets have any significant residual value at the end of their useful life.

4. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

We are party to an agreement with Kinder Morgan Energy Partners, L.P. ("KMP") for a 50/50 joint development of the Midcontinent Express pipeline. Construction of the approximately 500-mile pipeline was completed and natural gas transportation service commenced August 1, 2009 on the pipeline from Delhi, Louisiana, to an interconnect with the Transco interstate natural gas pipeline in Butler, Alabama. Interim service began on the pipeline from Bennington, Oklahoma, to Delhi in April 2009. In July 2008, Midcontinent Express Pipeline LLC ("MEP"), the entity formed to construct, own and operate this pipeline, completed an open season with respect to a capacity expansion of the pipeline from the current capacity of 1.4 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to an interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is expected to be completed in the latter part of 2010. This expansion was approved by the Federal Energy Regulatory Commission (the "FERC") in September 2009.

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

Fayetteville Express Pipeline LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC ("FEP"), the entity formed to construct, own and operate this pipeline, received FERC approval of its application for authority to construct and operate this pipeline. That order is currently subject to a limited request for rehearing. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. The pipeline project is expected to be in service by the end of 2010. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America ("NGPL") in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

Capital Contributions to Affiliates

During the year ended December 31, 2009, we contributed $664.5 million to MEP. FEP's capital expenditures are being funded under a credit facility. All of our contributions to FEP were reimbursed to us in 2009, including $9.0 million that we contributed in 2008.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, MEP and FEP (on a 100% basis):

	December 31, 2009	December 31, 2008
Current assets	$ 33,794	$ 9,953
Property, plant and equipment, net	2,576,031	1,012,006
Other assets	19,658	-
Total assets	$ 2,629,483	$ 1,021,959
Current liabilities	$ 105,951	$ 163,379
Non-current liabilities	1,198,882	840,580
Equity	1,324,650	18,000
Total liabilities and equity	$ 2,629,483	$ 1,021,959

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Revenue	$ 98,593	$ -	$ -	$ -
Operating income	47,818	-	-	-
Net income	36,555	1,057	-	-

As stated above, MEP was placed into service during 2009.

5. NET INCOME PER LIMITED PARTNER UNIT:

Our net income for partners' capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the IDRs pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. As discussed in Note 2, the adoption of a new accounting principle required us to change our calculation of earnings per unit during periods where earnings exceeded distributions; earnings in excess of distributions are now allocated to the General Partner and Limited Partners based on their respective ownership interests. Previously, a portion of earnings in excess of distributions had been allocated to the General Partner with respect to the IDRs. We have applied this change in accounting principle retrospectively; therefore, earnings per unit amounts for prior periods have been restated.

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income attributable to partners	$ 791,542	$ 866,023	$ 261,824	$ 676,139
General Partner's interest in net income	365,362	315,896	91,011	235,876
Limited Partner's interest in net income	426,180	550,127	170,813	440,263
Additional earnings allocated from General Partner	468	-	-	-
Distributions on employee unit awards, net of allocation to General Partner	(2,760)	(153)	-	-
Net income available to Limited Partners	$ 423,888	$ 549,974	$ 170,813	$ 440,263
Weighted average Limited Partner units – basic	167,337,192	146,871,261	137,624,934	132,618,053
Basic net income per Limited Partner unit	$ 2.53	$ 3.74	$ 1.24	$ 3.32
Weighted average Limited Partner units	167,337,192	146,871,261	137,624,934	132,618,053
Dilutive effect of Unit Grants	431,789	219,347	388,432	259,099
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	167,768,981	147,090,608	138,013,366	132,877,152
Diluted net income per Limited Partner unit	$ 2.53	$ 3.74	$ 1.24	$ 3.31

6. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2009	December 31, 2008	
ETP Senior Notes:			
5.95% Senior Notes, due February 1, 2015	$ 750,000	$ 750,000	Payable upon maturity. Interest is paid semi-annually.
5.65% Senior Notes, due August 1, 2012	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.125% Senior Notes, due February 15, 2017	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.625% Senior Notes, due October 15, 2036	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.0% Senior Notes, due July 1, 2013	350,000	350,000	Payable upon maturity. Interest is paid semi-annually.
6.7% Senior Notes, due July 1, 2018	600,000	600,000	Payable upon maturity. Interest is paid semi-annually.
7.5% Senior Notes, due July 1, 2038	550,000	550,000	Payable upon maturity. Interest is paid semi-annually.
9.7% Senior Notes due March 15, 2019	600,000	600,000	Put option on March 15, 2012. Payable upon maturity. Interest is paid semi-annually.
8.5% Senior Notes due April 15, 2014	350,000	-	Payable upon maturity. Interest is paid semi-annually.
9.0% Senior Notes due April 15, 2019	650,000	-	Payable upon maturity. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Notes, due November 17, 2014	88,000	88,000	Payable upon maturity. Interest is paid semi-annually.
5.54% Senior Unsecured Notes, due November 17, 2016	125,000	125,000	Payable upon maturity. Interest is paid semi-annually.
5.64% Senior Unsecured Notes, due May 24, 2017	82,000	82,000	Payable upon maturity. Interest is paid semi-annually.
5.89% Senior Unsecured Notes, due May 24, 2022	150,000	150,000	Payable upon maturity. Interest is paid semi-annually.
6.16% Senior Unsecured Notes, due May 24, 2037	75,000	75,000	Payable upon maturity. Interest is paid semi-annually.
5.36% Senior Unsecured Notes, due December 9, 2020	175,000	-	Payable upon maturity. Interest is paid semi-annually.
5.66% Senior Unsecured Notes, due December 9, 2024	175,000	-	Payable upon maturity. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	24,000	36,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
Medium Term Note Program:			
7.17% Series A Senior Secured Notes	-	2,400	Matured in November 2009.
7.26% Series B Senior Secured Notes	6,000	8,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	4,571	9,142	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	5,750	11,500	Annual payments of $5,750 due each August 15 through 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	33,100	45,550	Annual payments of $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	6,000	7,000	Annual payments of $1,000 due each August 15 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.89% Series H Senior Secured Notes	5,091	5,818	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility	150,000	902,000	See terms below under “ETP Credit Facility”.
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	10,000	See terms below under “HOLP Credit Facility”.
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 8.06% and 7.91% for December 31, 2009 and 2008, respectively	7,898	11,249	Due in installments through 2014.
Other	2,224	2,565	Due in installments through 2024.
Unamortized discounts	(12,829)	(13,477)	
	6,217,805	5,663,747	
Current maturities	(40,887)	(45,198)	
	$ 6,176,918	$ 5,618,549	

Future maturities of long-term debt for each of the next five years and thereafter are as follows:

2010	$ 40,887
2011	44,567
2012	572,838
2013	372,523
2014	443,519
Thereafter	4,743,471
	$ 6,217,805

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). The Partnership may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership’s subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

In April 2009, we completed a public offering of $350.0 million aggregate principal amount of 8.5% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.0% Senior Notes due 2019 (collectively the “2009 ETP Notes”). The offering of the 2009 ETP Notes closed on April 7, 2009 and we used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

Transwestern Senior Unsecured Notes

Transwestern’s long-term debt consists of $213.0 million remaining principal amount of notes assumed in connection with the Transwestern acquisition, $307.0 million aggregate principal amount of notes issued in May 2007, and $350.0 million aggregate principal amount of notes issued in December 2009. The proceeds from the notes issued in December 2009 were used by Transwestern to repay amounts under an intercompany loan agreement. No principal payments are required under any of the Transwestern notes prior to their respective maturity dates. The Transwestern notes rank pari passu with Transwestern’s other unsecured debt. The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. Interest is paid semi-annually.

Transwestern’s debt agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the “HOLP Notes”).

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity, under the Amended and Restated Credit Agreement). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of December 31, 2009, there was a balance outstanding in the ETP Credit Facility of $150.0 million in revolving credit loans and approximately $62.2 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2009 was 0.78%. The total amount available under the ETP Credit Facility, as of December 31, 2009, which is reduced by any letters of credit, was approximately $1.79 billion. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility (total book value as of December 31, 2009 of approximately $1.2 billion). At December 31, 2009, there was $10.0 million outstanding in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of December 31, 2009 was $64.0 million.

Covenants Related to Our Credit Agreements

The agreements related to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions. The agreements and indentures related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to ETP and the Operating Companies, including the maintenance of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens as described in further detail below.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) the Partnership's and certain of the Partnership's subsidiaries, ability to, among other things:

Ÿ incur indebtedness;

Ÿ grant liens;

Ÿ enter into mergers;

- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by the Partnership and its subsidiaries;
- engage in transactions with affiliates;
- enter into restrictive agreements; and
- enter into speculative hedging contracts.

The credit agreement related to the ETP Credit Facility also contains a financial covenant that provides that on each date we make a distribution, the leverage ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1, with a permitted increase to 5.5 to 1 during a specified acquisition period, as defined in the ETP Credit Facility. This financial covenant could therefore restrict our ability to make cash distributions to our Unitholders, our general partner and the holder of our incentive distribution rights.

The agreements related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to HOLP, including the maintenance of various financial and leverage covenants and limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The financial covenants require HOLP to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not less than 2.25 to 1. These debt agreements also provide that HOLP may declare, make, or incur a liability to make restricted payments during each fiscal quarter, if: (a) the amount of such restricted payment, together with all other restricted payments during such quarter, do not exceed the amount of Available Cash (as defined in the agreements related to the HOLP Notes and HOLP Credit Facility) with respect to the immediately preceding quarter (which amount is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes during the last quarter and in addition, in the third, second and first quarters preceding a quarter in which a scheduled principal payment is to be made on the HOLP Notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates), (b) no default or event of default exists before such restricted payments, and (c) the amounts of HOLP's restricted payment is not disproportionately greater than the payment amount from ETC OLP utilized to fund payment obligations of ETP and its general partner with respect to ETP's Common Units.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities and the note agreements related to the HOLP Notes could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

We are required to assess compliance quarterly and we were in compliance with all requirements, limitations, and covenants related to our debt agreements as of December 31, 2009.

7. PARTNERS' CAPITAL

Limited Partner Units

Limited Partner interests are represented by Common and Class E Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement. As of December 31, 2009, there were issued and outstanding 179,274,747 Common Units representing an aggregate 98.1% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that ETP GP has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance.

IDRs represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. Please read “Quarterly Distributions of Available Cash” below. ETP GP owns all of the IDRs.

Common Units

The change in Common Units is as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Number of Units, beginning of period	152,102,471	142,069,957	136,981,221	110,726,999
Common Units issued in connection with public offerings	23,575,000	9,662,500	5,000,000	-
Common Units issued in connection with certain acquisitions	1,450,076	53,893	27,348	-
Common Units issued in connection with the Equity Distribution Agreement	1,891,691			
Issuance of restricted Common Units	-	-	-	167,265
Conversion of Class G Units to Common Units	-	-	-	26,086,957
Issuance of Common Units under the equity incentive plans	255,509	316,121	61,388	-
Number of Units, end of period	179,274,747	152,102,471	142,069,957	136,981,221

Our Common Units are registered under the Securities Act of 1934 and are listed for trading on the NYSE. Each holder of a Common Unit is entitled to one vote per unit on all matters presented to the Limited Partners for a vote. In addition, if at any time any person or group (other than our General Partner and its affiliates) owns beneficially 20% or more of all Common Units, any Common Units owned by that person or group may not be voted on any matter and are not considered to be outstanding when sending notices of a meeting of Unitholders (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under the Partnership Agreement. The Common Units are entitled to distributions of Available Cash as described below under “Quarterly Distributions of Available Cash.”

Public Offerings

The following table summarizes our public offerings of Common Units, all of which have been registered under the Securities Act of 1933, as amended:

Date	Number of Common Units (1)	Price per Unit	Net Proceeds	Use of Proceeds
December 2007 (2)	5,750,000	$ 48.81	$ 269.4	(3)
July 2008	8,912,500	39.45	337.5	(4)
January 2009	6,900,000	34.05	225.4	(4)
April 2009	9,775,000	37.55	352.4	(5)
October 2009	6,900,000	41.27	276.0	(4)
January 2010	9,775,000	44.72	423.6	(4)(5)

(1) Number of Common Units includes the exercise of the overallotment options by the underwriters.
(2) Amounts include the exercise of the overallotment option by the underwriters in January 2008.
(3) Proceeds were used to repay amounts outstanding under ETP's prior term loan facility.
(4) Proceeds were used to repay amounts outstanding under the ETP Credit Facility.
(5) Proceeds were used to fund capital expenditures and capital contributions to joint ventures, as well as for general partnership purposes.

Equity Distribution Program

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC ("UBS"). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, common units having an aggregate offering price of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During 2009, we issued 2,079,593 of our common units pursuant to this agreement, 1,891,691 of which have been settled as of December 31, 2009. The proceeds of approximately $81.5 million, net of commissions, were used to repay amounts outstanding under our revolving credit facility.

Equity Incentive Plan Activity

As discussed in Note 8, we issue Common Units to employees and directors upon vesting of awards granted under our equity incentive plans. Upon vesting, participants in the equity incentive plans may elect to have a portion of the Common Units to which they are entitled withheld by the Partnership to satisfy tax-withholding obligations.

Other Common Unit Activity

On November 1, 2006, we issued 26,086,957 Class G Units to ETE for aggregate proceeds of $1.20 billion in order to fund a portion of the Transwestern Acquisition and to repay indebtedness we incurred in connection with the Titan acquisition. During fiscal year 2007, we converted all of the Class G Units to Common Units.

Class E Units

There are 8,853,832 Class E Units outstanding that are reported as treasury units. These Class E Units are entitled to aggregate cash distributions equal to 11.1% of the total amount of cash distributed to all Unitholders, including the Class E Unitholders, up to $1.41 per unit per year. Management plans to leave the Class E Units in the form described here indefinitely. In the event of our termination and liquidation, the Class E Units will be allocated 1% of any gain upon liquidation and will be allocated any loss upon liquidation to the same extent as Common Units. After the allocation of such amounts, the Class E Units will be entitled to the balance in their capital accounts, as adjusted for such termination and liquidation. The terms of the Class E Units were determined in order to provide us with the opportunity to minimize the impact of our ownership of Heritage Holdings, including the $57.4 million in deferred tax liabilities of Heritage Holdings that were included in the purchase of Heritage Holdings. The Class E Units are treated as treasury stock for accounting purposes because they are owned by our wholly-owned subsidiary, Heritage Holdings. Due to the ownership of the Class E Units by this corporate subsidiary, the payment of distributions on the Class E Units will result in annual tax payments by Heritage Holdings at corporate federal income tax rates, which tax payments will reduce the amount of cash that would otherwise be available for distribution to us as the owner of Heritage Holdings. Because distributions on the Class E Units will be available to us as the owner of Heritage Holdings, those funds will be available, after payment of taxes, for general partnership purposes, including to satisfy working capital requirements, for the repayment of outstanding debt and to make distributions to the Unitholders. Because the Class E Units are not entitled to receive any allocation of Partnership income, gain, loss, deduction or credit that is attributable to our ownership of Heritage Holdings, such amounts will instead be allocated to the General Partner in accordance with its respective interest and the remainder to all Unitholders other than the holders of Class E Units pro rata. In the event that Partnership distributions exceed $1.41 per unit annually, all such amounts in excess thereof will be available for distribution to Unitholders other than the holders of Class E Units in proportion to their respective interests.

Quarterly Distributions of Available Cash

The Partnership Agreement requires that we distribute all of our Available Cash to our Unitholders and our General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any of our fiscal quarters, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by the General Partner in its sole discretion to provide for the proper conduct of our business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in our Partnership Agreement.

Our distributions from operating surplus for any quarter in an amount equal to 100% of Available Cash will generally be made as follows, subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of quarterly cash distributions are achieved ($0.275 per unit):

- First, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received $0.25 per unit for such quarter (the “minimum quarterly distribution”);
- Second, 100% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, until each Common Unit has received $0.275 per unit for such quarter (the “first target distribution”);
- Third, 87% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, 13% to the holders of IDRs, pro rata, until each Common Unit has received at least $0.3175 per unit for such quarter (the “second target distribution”);

- Fourth, 77% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, 23% to the holders of IDRs, pro rata, until each Common Unit has received at least $0.4125 per unit for such quarter; (the "third target distribution"); and
- Fifth, thereafter, 52% to all Common and Class E Unitholders and the General Partner, in accordance with their percentage interests, 48% to the holders of Incentive Distribution Rights, pro rata.

The allocation of distributions among the Common and Class E Unitholders and the General Partner is based on their respective interests as of the record date for such distributions. As of December 31, 2009, the Common and Class E Unitholders collectively held 98.1% of the ownership interests in us, and the General Partner held a 1.9% interest.

Notwithstanding the foregoing, any arrearage in the payment of the minimum quarterly distribution for all prior quarters and the distributions on each Class E unit may not exceed $1.41 per year.

Distributions declared during the periods presented below are summarized as follows:

	Record Date	Payment Date	Amount per Unit	
Calendar Year Ended December 31, 2009	November 9, 2009	November 16, 2009	$	0.89375
	August 7, 2009	August 14, 2009		0.89375
	May 8, 2009	May 15, 2009		0.89375
	February 6, 2009	February 13, 2009		0.89375
Calendar Year Ended December 31, 2008	November 10, 2008	November 14, 2008	$	0.89375
	August 7, 2008	August 14, 2008		0.89375
	May 5, 2008	May 15, 2008		0.86875
	February 1, 2008 (1)	February 14, 2008		1.12500
Transition Period Ended December 31, 2007	October 5, 2007	October 15, 2007	$	0.82500
Fiscal Year Ended August 31, 2007	July 2, 2007	July 16, 2007	$	0.80625
	April 6, 2007	April 13, 2007		0.78750
	January 4, 2007	January 15, 2007		0.76875
	October 5, 2006	October 16, 2006		0.75000

(1) One-time four month distribution – On January 18, 2008 our Board of Directors approved the management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP's distribution amount related to the four months ended December 31, 2007 was $1.125 per Common Unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This distribution was paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

On January 28, 2010, we declared a cash distribution for the fourth quarter ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized. We paid this distribution on February 15, 2010 to Unitholders of record at the close of business on February 8, 2010.

The total amounts of distributions declared during the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007 are as follows (all from Available Cash from our operating surplus and are shown in the year with respect to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 629,263	$ 537,731	$ 160,672	$ 396,095
Class E Units (1)	12,484	12,484	3,121	12,484
Class G Units (2)	-	-	-	40,598
General Partner interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$ 1,011,738	$ 866,112	$ 254,678	$ 685,235

(1) See explanation of Class E Units above.
(2) Distributions declared prior to the Class G Units converting to Common Units (see detail above).

Upon their conversion to Common Units, the Class G Units ceased to have the right to participate in distributions of available cash from operating surplus.

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31, 2009	December 31, 2008
Net gain on commodity related hedges	$ 1,991	$ 8,735
Net gain (loss) on interest rate hedges	(125)	161
Unrealized gains (losses) on available-for-sale securities	4,941	(5,983)
Total AOCI, net of tax	$ 6,807	$ 2,913

8. UNIT-BASED COMPENSATION PLANS:

We have issued equity awards to employees and directors under the following plans:

- ***2008 Long-Term Incentive Plan**.* On December 16, 2008, ETP Unitholders approved the ETP 2008 Long-Term Incentive Plan (the “2008 Incentive Plan”), which provides for awards of options to purchase ETP Common Units, awards of restricted units, awards of phantom units, awards of Common Units, awards of distribution equivalent rights (“DERs”), awards of Common Unit appreciation rights, and other unit-based awards to employees of ETP, ETP GP, ETP LLC, a subsidiary or their affiliates, and members of ETP LLC’s board of directors, which we refer to as our board of directors. Up to 5,000,000 ETP Common Units may be granted as awards under the 2008 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2008 Incentive Plan. The 2008 Incentive Plan is effective until December 16, 2018 or, if earlier, the time which all available units under the 2008 Incentive Plan have been issued to participants or the time of termination of the plan by our board of directors. As of December 31, 2009, a total of 4,213,111 ETP Common Units remain available to be awarded under the 2008 Incentive Plan.
- ***2004 Unit Plan**.* Our Amended and Restated 2004 Unit Award Plan (the “2004 Unit Plan”) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers and directors. Any awards that are forfeited, or which expire for any reason or any units, which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. As of December 31, 2009, 5,578 ETP Common Units were available for future grants under the 2004 Unit Plan.

Employee Grants

Prior to December 2007, substantially all of the awards granted to employees required the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three-year period with 100% of such one-third vesting if the total return for our units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the Compensation Committee, 65% of such one-third vesting if the total return of our units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of our units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of our units for the year plus the aggregate per unit cash distributions received for the year. Non-cash compensation expense is recorded for these awards based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded.

In October 2008, the Compensation Committee determined that, of the unit awards subject to the achievement of performance objectives, 25% of the ETP Common Units subject to such awards eligible to vest on September 1, 2007 became vested and 75% of the awards were forfeited based on our performance for the twelve-month period ended August 31, 2008. In October 2008, the Compensation Committee approved a special grant of the new unit awards that entitled each holder to receive a number of ETP Common Units equal to the number of ETP Common Units forfeited as of September 1, 2007, which new unit awards became fully vested on October 15, 2008. These Compensation Committee actions affected all employee unit awards including unit awards granted to our executive officers.

Commencing in December 2007, we have also granted restricted unit awards to employees that vest over a specified time period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. Upon vesting, ETP Common Units are issued. The unit awards under our equity incentive plans generally require the continued employment of the recipient during the vesting period; however, the Compensation Committee has complete discretion to accelerate the vesting of unvested unit awards.

In 2008 and 2009, the Compensation Committee approved the grant of new unit awards, which vest over a five-year period at 20% per year, subject to continued employment through each specified vesting date. These unit awards entitle the recipients of the unit awards to receive, with respect to each Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per Common Unit made by us on our Common Units promptly following each such distribution by us to our Unitholders. We refer to these rights as “distribution equivalent rights.”

Prior to 2008 and 2009, units were generally awarded without distribution equivalent rights. For such awards, we calculated the grant-date fair value based on the market value of the underlying units, reduced by the present value of the distributions expected to be paid on the units during the requisite service period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the distribution yield at that time.

Director Grants

Under our equity incentive plans, our non-employee directors each receive unvested ETP Common Units with a grant-date fair value of $50,000 each year. These non-employee director grants vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

Award Activity

The following table shows the activity of the awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2008	1,372,568	$ 36.83
Awards granted	763,190	43.56
Awards vested	(336,386)	36.02
Awards forfeited	(108,780)	39.17
Unvested awards as of December 31, 2009	1,690,592	39.88

The balance above for unvested awards as of December 31, 2008 includes 150,852 unit awards with a grant-date fair value of $43.96 per unit, which were granted prior to 2008 and were subject to a performance condition, as described above. These remaining performance awards vested in 2009, and none of the unvested unit awards outstanding as of December 31, 2009 contain performance conditions.

During the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, the weighted average grant-date fair value per unit award granted was $43.56, $33.86, $42.46 and $43.73, respectively. The total fair value of awards vested was $14.7 million, $14.6 million, $3.3 million and $7.9 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2009, a total of 1,690,592 unit awards remain unvested, for which ETP expects to recognize a total of $50.9 million in compensation expense over a weighted average period of 1.9 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by the President of the entity that owns our General Partner, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officers. These rights include the economic benefits of ownership of these ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE.

During the years ended December 31, 2008 and August 31, 2007, unvested rights related to 450,000 ETE common units and 675,000 ETE common units, respectively, with aggregate grant-date fair values of $10.3 million and $23.5 million, respectively, were awarded to ETP officers. During the year ended December 31, 2008, unvested rights related to 240,000 ETE common units were forfeited. During the years ended December 31, 2009 and 2008 and the four months ended December 31, 2007, ETP officers vested in rights related to 165,000 ETE common units, 135,000 ETE common units, and 55,000 ETE common units, respectively, with aggregate fair values upon vesting of $4.6 million, $3.5 million, and $1.9 million, respectively.

We are recognizing non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded the ETP employees assuming no forfeitures. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized non-cash compensation expense, net of forfeitures, of $6.4 million, $3.5 million, $3.6 million and $5.2 million, respectively, as a result of these awards.

As of December 31, 2009, rights related to 530,000 ETE common units remain outstanding, for which we expect to recognize a total of $6.8 million in compensation expense over a weighted average period of 1.9 years.

9. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Current expense (benefit):				
Federal	$ (8,851)	$ (180)	$ 2,990	$ 7,896
State	9,662	12,216	5,705	9,803
Total	811	12,036	8,695	17,699
Deferred expense (benefit):				
Federal	11,541	(5,634)	1,482	(4,598)
State	425	278	612	557
Total	11,966	(5,356)	2,094	(4,041)
Total income tax expense (benefit)	$ 12,777	$ 6,680	$ 10,789	$ 13,658

On May 18, 2006, the State of Texas enacted House Bill 3, which replaced the existing state franchise tax with a “margin tax.” In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin, which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law’s effective date of January 1, 2007. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $8.5 million, $10.5 million, $3.9 million and $6.9 million, respectively.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. The difference between the statutory rate and the effective rate is summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate, net of federal benefit	1.03%	1.25%	1.82%	1.25%
Earnings not subject to tax at the Partnership level	(34.44%)	(35.48%)	(32.86%)	(34.25%)
Effective tax rate	1.59%	0.77%	3.96%	2.00%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the deferred tax liability were as follows:

	December 31, 2009	December 31, 2008
Property, plant and equipment	$ 112,707	$ 105,032
Other, net	290	(3,846)
Total deferred tax liability	112,997	101,186
Less current deferred tax liability	-	589
Total long-term deferred tax liability	$ 112,997	$ 100,597

10. MAJOR CUSTOMERS AND SUPPLIERS:

Our major customers are in the natural gas operations segments. Our natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while our NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively. Management believes that our portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer accounted for 10% or more of our consolidated revenue.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Propane segments				
Unaffiliated:				
M.P. Oils, Ltd.	15.1%	14.9%	14.2%	20.7%
Targa Liquids	14.3%	15.0%	15.9%	22.6%
Affiliated:				
Enterprise	50.3%	50.7%	50.6%	22.1%

Enterprise GP Holdings, L.P. and its subsidiaries (“Enterprise” or “EPE”) became related parties on May 7, 2007 as discussed in Note 14. Titan purchases the majority of its propane from Enterprise pursuant to an agreement that expires in March 2010 and contains renewal and extension options.

We sold our investment in M-P Energy in October 2007. In connection with the sale, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

This concentration of suppliers may impact our overall operations either positively or negatively. However, management believes that the diversification of suppliers is sufficient to enable us to purchase all of our supply needs at market prices without a material disruption of operations if supplies are interrupted from any of our existing sources. Although no assurances can be given that supplies of natural gas, propane and NGLs will be readily available in the future, we expect a sufficient supply to continue to be available.

11. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline. Approval from the FERC is still pending.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act ("NGA") proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern's tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern's existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern's existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity ("Order"). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service effective March 2009.

Guarantees

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the "MEP Facility"), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP's ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

The commitment amount under the MEP Facility was originally $1.4 billion. In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by us or KMP. In October 2009, the members made additional capital contributions to MEP, which MEP used to further reduce the outstanding borrowings under the MEP Facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275.0 million.

As of December 31, 2009, MEP had $29.5 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to our 50% guarantee of MEP's outstanding borrowings and letters of credit were $14.7 million and $16.6 million, respectively, as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.3%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the “FEP Facility”). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of December 31, 2009, FEP had $355.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to our 50% guarantee of FEP’s outstanding borrowings was $177.5 million as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $19.8 million, $17.2 million, $9.4 million and $33.2 million for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, respectively.

Future minimum lease commitments for such leases are:

2010	$	27,216
2011		24,786
2012		22,522
2013		20,385
2014		17,907
Thereafter		214,088

We have forward commodity contracts, which are expected to be settled by physical delivery. Short-term contracts, which expire in less than one year require delivery of up to 390,564 MMBtu/d. Long-term contracts require delivery of up to 125,551 MMBtu/d and extend through May 2014.

During fiscal year 2007, we entered into a long-term agreement with CenterPoint Energy Resources Corp (“CenterPoint”) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of the agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel storage facility.

We have a transportation agreement with TXU Portfolio Management Company, LP (“TXU Shipper”) to transport a minimum of 100,000 MMBtu per year through 2012. We also have two natural gas storage agreements with TXU Shipper to store gas at two natural gas facilities that are part of the ET Fuel System that expire in 2012. As of December 31, 2009 and 2008 and August 31, 2007, respectively, the Partnership was entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month periods ended each May 31st. As a result, the Partnership recognized approximately $11.7 million, $10.7 million and $10.8 million in additional fees during the second quarters of 2009 and 2008 and the third fiscal quarter of 2007, respectively.

We have signed long-term agreements with several parties committing firm transportation volumes into the East Texas pipeline. Those commitments include an agreement with XTO Energy Inc. (“XTO”) to deliver approximately 200,000 MMBtu/d of natural gas into the pipeline that expires in June 2012. Exxon Mobil Corporation (“ExxonMobil”) and XTO announced an agreement whereby ExxonMobil will acquire XTO. The pending acquisition, expected to be completed in the second quarter of 2010, is not expected to result in any changes to these commitments.

We also have two long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts require an aggregated capacity of approximately 238,000 MMBtu/d of natural gas and extend through 2011.

Titan has a purchase contract with Enterprise (see Note 14) to purchase the majority of Titan’s propane requirements. The contract continues until March 2010 and contains renewal and extension options. The contract contains various service level agreements between the parties.

In connection with the sale of our investment in M-P Energy in October 2007, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

We have commitments to make capital contributions to our joint ventures, for which we expect to make capital contributions of between $90 million and $105 million during 2010.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

FERC/CFTC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the “Order and Notice”) that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC’s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts Inside FERC Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the

Waha and Permian Hubs in west Texas on two dates. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. The FERC specified that it was also seeking to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP's trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement settles all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims against us, including existing litigation claims as well as any new claims that may be asserted against this fund. An administrative law judge appointed by the FERC will determine the validity of any third party claim against this fund. Any party who receives money from this fund will be required to waive all claims against us related to this matter. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by exceeding the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

We made the $5.0 million payment and established the $25.0 million fund in October 2009. The allocation of the $25.0 million fund is expected to be determined in 2010.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE alleging damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETE contains an additional allegation that we and ETE transported gas in a manner that favored our affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have moved to compel arbitration and/or contested subject-matter jurisdiction in some of these cases. In one of these cases, the Texas Supreme Court ruled on July 3, 2009 that the state district court erred in ruling that a plaintiff was entitled to pre-arbitration discovery and therefore remanded to the state district court with a direction to rule on our original motion to compel arbitration pursuant to the terms of the arbitration clause in a natural gas contract between us and the plaintiff. This plaintiff has filed a motion with the Texas Supreme Court requesting a rehearing of the ruling.

We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. This action is currently on appeal before the First Court of Appeals, Houston, Texas.

A consolidated class action complaint has been filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 28, 2009, these decisions were appealed by the plaintiffs to the United States Court of Appeals for the Fifth Circuit.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted our motion to dismiss the complaint. On September 10, 2009, this decision was appealed by the plaintiff to the United States Court of Appeals for the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obliged to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations and our liquidity.

In re Natural Gas Royalties Qui Tam Litigation. MDL Docket No. 1293 (D. WY), Jack Grynberg, an individual, has filed actions against a number of companies, including Transwestern, now transferred to the U.S. District Court for the District of Wyoming, for damages for mis-measurement of gas volumes and Btu content, resulting in lower royalties to mineral interest owners. On October 20, 2006, the District Judge adopted in part the earlier recommendation of the Special Master in the case and ordered the dismissal of the case against Transwestern. Transwestern believes that its measurement practices conformed to the terms of its FERC Gas Tariff, which were filed with and approved by the FERC. As a result, Transwestern believes that is has meritorious defenses to these lawsuits (including FERC-related affirmative defenses, such as the filed rate/tariff doctrine, the primary/exclusive jurisdiction of the FERC, and the defense that Transwestern complied with the terms of its tariffs) and will continue to vigorously defend against them, including any appeal which may be taken from the dismissal of the Grynberg case. A hearing was held on April 24, 2007 regarding Transwestern's Supplemental Brief for Attorneys' fees which was filed on January 8, 2007 and the issues are submitted and are awaiting a decision. Grynberg moved to have the cases he appealed remanded to the district court for consideration in light of a recently-issued Supreme Court case. The defendants/appellees opposed the motion. The Tenth Circuit motions panel referred the remand motion to the merits panel to be carried with the appeals. Grynberg's opening brief was filed on or about July 31, 2007. Appellee's opposition brief was filed on or about November 21, 2007. Appellee Transwestern filed its separate response brief on January 11, 2008 and Grynberg's reply brief was filed in June 2008 and the hearing on all briefs was held in September 2008. On March 17, 2009, the Tenth Circuit affirmed the District Court's dismissal. Appellant sought appellate rehearing on the matter and the petition for rehearing was denied on May 4, 2009. A petition for writ of certiorari was filed by the Appellant on August 3, 2009, and the Supreme Court denied the petition for writ of certiorari on October 5, 2009. We do not believe the outcome of this case will have a material adverse effect on our financial position, results of operations or cash flows.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were engaged in ongoing litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the ("Cushion Gas Litigation"). Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. AEP is appealing the court decision. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of December 31, 2009 and 2008, accruals of approximately $11.1 million and $8.5 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of December 31, 2008, an accrual of $21.0 million was recorded as accrued and other current liabilities and other non-current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters, and we did not have any such accruals as of December 31, 2009.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.6 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the EPA’s Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the "EPA") regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to HOLP, it is believed that HOLP's liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2009 or our December 31, 2008 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of December 31, 2009 and 2008, accruals on an undiscounted basis of $12.6 million and $13.3 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for all of the above environmental matters is adequate to cover the potential exposure for clean-up costs.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT") under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as ("high consequence areas.") Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

12. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

See Note 2 for further discussion of our accounting for derivative instruments and hedging activities.

Commodity Price Risk

The following table details the outstanding commodity-related derivatives:

		December 31, 2009		December 31, 2008	
	Commodity	Notional Volume MMBtu	Maturity	Notional Volume MMBtu	Maturity
Mark to Market Derivatives					
Basis Swaps IFERC/NYMEX	Gas	72,325,000	2010-2011	15,720,000	2009-2011
Swing Swaps IFERC	Gas	(38,935,000)	2010	(58,045,000)	2009
Fixed Swaps/Futures	Gas	4,852,500	2010-2011	(20,880,000)	2009-2010
Options - Puts	Gas	2,640,000	2010	-	N/A
Options - Calls	Gas	(2,640,000)	2010	-	N/A
Forwards/Swaps - in Gallons	Propane/Ethane	6,090,000	2010	47,313,002	2009
Fair Value Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(22,625,000)	2010	-	N/A
Fixed Swaps/Futures	Gas	(27,300,000)	2010	-	N/A
Hedged Item - Inventory	Gas	27,300,000	2010	-	N/A
Cash Flow Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(13,225,000)	2010	(9,085,000)	2009
Fixed Swaps/Futures	Gas	(22,800,000)	2010	(9,085,000)	2009
Forwards/Swaps - in Gallons	Propane/Ethane	20,538,000	2010	-	N/A

We expect gains of $2.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the consolidated statements of operations on a net basis. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the year ended December 31, 2008, net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007 and net gains of approximately $2.2 million for the fiscal year ended August 31, 2007. There were no gains or losses associated with trading activities during the year ended December 31, 2009.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We have previously managed a portion of our current and future interest rate exposures by utilizing interest rate swaps. As of December 31, 2009, we do not have any interest rate swaps outstanding.

In December 2009, we settled forward starting swaps with notional amounts of $500.0 million for a cash payment of $11.1 million. In April 2009, we terminated forward starting swaps with notional amounts of $100.0 million and $150.0 million for an insignificant amount.

In January 2010, we entered into interest rate swaps with notional amounts of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate that mature in July 2013 and February 2015, respectively. These swaps hedge against changes in the fair value of our fixed rate debt.

Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2009 and December 31, 2008:

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Derivatives designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 669	$ 10,665	$ (24,035)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	8,443	918	(201)	(119)
Total derivatives designated as hedging instruments		$ 9,112	$ 11,583	$ (24,236)	$ (1,623)
Derivatives not designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	72,851	432,614	(36,950)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	3,928	17,244	(241)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	-	-	-	(51,643)
Total derivatives not designated as hedging instruments		$ 76,779	$ 449,858	$ (37,191)	$ (443,282)
Total derivatives		$ 85,891	$ 461,441	$ (61,427)	$ (444,905)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets. The Partnership had net deposits with counterparties of $79.7 million and $78.2 million as of December 31, 2009 and December 31, 2008, respectively.

The following tables detail the effect of the Partnership's derivative assets and liabilities in the consolidated statements of operations for the periods presented:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 3,143	$ 17,461	$ 21,406	$ 181,765
Interest Rate Swap Derivatives	Interest Expense	-	-	-	(4,719)
Total		$ 3,143	$ 17,461	$ 21,406	$ 177,046

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 9,924	$ 42,874	$ 8,673	$ 162,340
Interest Rate Swap Derivatives	Interest Expense	287	646	(51)	920
Total		$ 10,211	$ 43,520	$ 8,622	$ 163,260

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ -	$ (8,347)	$ 8,472	$ 183
Interest Rate Swap Derivatives	Interest Expense	-	-	-	(1,813)
Total		$ -	$ (8,347)	$ 8,472	$ (1,630)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in fair value hedging relationships:					
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ 60,045	$ -	$ -	$ -
Total		$ 60,045	$ -	$ -	$ -

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives not designated as hedging instruments:					
Commodity Derivatives	Cost of Products Sold	$ 99,807	$ 12,478	$ 9,886	$ 30,028
Trading Commodity Derivatives	Revenue	-	(28,283)	(2,298)	5,228
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	39,239	(50,989)	(1,013)	31,032
Total		$ 139,046	$ (66,794)	$ 6,575	$ 66,288

We recognized an $18.6 million unrealized loss, a $35.5 million unrealized gain, a $13.2 million unrealized gain and an $8.5 million unrealized loss on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships and amounts classified as trading activity) for the years ended December 31, 2009 and 2008, four months ended December 31, 2007 and the year August 31, 2007, respectively. In addition, for the year ended December 31, 2009, we recognized unrealized gains of $48.6 million on commodity derivatives and related hedged inventory accounted for as fair value hedges. There were no unrealized gains or losses on fair value hedging commodity derivatives in the prior years since we commenced fair hedge accounting on our storage inventory in April 2009.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties’ financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

13. RETIREMENT BENEFITS:

We sponsor a 401(k) savings plan, which covers virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. Prior to 2009, employer matching contributions were discretionary. We made matching contributions of $9.8 million, $9.7 million, $2.6 million and $8.5 million to the 401(k) savings plan for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively.

14. RELATED PARTY TRANSACTIONS:

On May 7, 2007, Ray Davis, previously the Co-Chairman of ETE and Co-Chairman and Co-Chief Executive Officer of ETP (retired August 15, 2007), and Natural Gas Partners VI, L.P. ("NGP") and affiliates of each, sold approximately 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise. In addition to the purchase of ETE Common Units, Enterprise acquired a non-controlling equity interest in ETE's General Partner, LE GP, LLC ("LE GP"). As a result of these transactions, EPE and its subsidiaries are considered related parties for financial reporting purposes.

On December 23, 2009, Dan L. Duncan and Ralph S. Cunningham were appointed as directors of ETE's general partner. Mr. Duncan is Chairman and a director of EPE Holdings, LLC, the general partner of Enterprise; Chairman and a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., or EPD; and Group Co-Chairman of EPCO, Inc. TEPPCO Partners, L.P., or TEPPCO, is also an affiliate of EPE. Dr. Cunningham is the President and Chief Executive Officer of EPE Holdings, LLC, the general partner of Enterprise. These entities and other affiliates of Enterprise are referred to herein collectively as the "Enterprise Entities." Mr. Duncan directly or indirectly beneficially owns various interests in the Enterprise Entities, including various general partner interests and approximately 77.1% of the common units of Enterprise and approximately 34% of the common units of EPD. On October 26, 2009, TEPPCO became a wholly owned subsidiary of Enterprise.

Our propane operations routinely enter into purchases and sales of propane with certain of the Enterprise Entities, including purchases under a long-term contract of Titan to purchase the majority of its propane requirements through certain of the Enterprise Entities. This agreement was in effect prior to our acquisition of Titan in 2006, and expires in March 2010 and contains renewal and extension options.

From time to time, our natural gas operations purchase from, and sell to, the Enterprise Entities natural gas and NGLs, in the ordinary course of business. We have a monthly natural gas storage contract with TEPPCO. Our natural gas operations and the Enterprise Entities transport natural gas on each other's pipelines and share operating expenses on jointly-owned pipelines.

The following table presents sales to and purchases from affiliates of Enterprise. Amounts reflected below for the year ended August 31, 2007 include transactions beginning on May 7, 2007, the date Enterprise became an affiliate. Volumes are presented in thousands of gallons for propane and NGLs and in billions of Btus for natural gas:

		Years Ended December 31,				Four Months Ended December 31, 2007		Year Ended August 31, 2007	
		2009		2008					
	Product	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars
Propane Operations:									
Sales	Propane	20,370	$ 14,046	13,230	$ 19,769	2,982	$ 4,619	1,470	$ 1,725
	Derivatives	-	5,915	-	2,442	-	1,857	-	22
Purchases	Propane	307,525	$ 305,148	318,982	$ 472,816	125,141	$ 192,580	61,660	$ 74,688
	Derivatives	-	38,392	-	20,993	-	-	-	1
Natural Gas Operations:									
Sales	NGLs	477,908	$ 374,020	58,361	$ 96,974	3,240	$ 4,726	464	$ 648
	Natural Gas	11,532	44,212	6,256	52,205	2,036	11,452	1,495	9,768
	Fees	-	(3,899)	-	5,093	-	610	-	-
Purchases	Natural Gas Imbalances	176	$ 1,164	3,488	$ (6,485)	313	$ (911)	3,120	$ 22,677
	Natural Gas	10,561	49,559	13,457	120,837	3,577	23,341	1,541	7,501
	Fees	-	(2,195)	-	876	-	311	-	-

As of December 31, 2009 and 2008, Titan had forward mark-to-market derivatives for approximately 6.1 million and 45.2 million gallons of propane at a fair value asset of $3.3 million and a fair value liability of $40.1 million, respectively, with Enterprise. In addition, as of December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 20.5 million gallons of propane at a fair value asset of $8.4 million with Enterprise.

The following table summarizes the related party balances with Enterprise on our consolidated balance sheets:

	December 31, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 47,005	$ 11,558
Accounts payable	3,518	567
Imbalance payable	694	(547)
Propane Operations:		
Accounts receivable	$ 3,386	$ 111
Accounts payable	31,642	33,308

Accounts receivable from related companies excluding Enterprise consist of the following:

	December 31, 2009	December 31, 2008
ETP GP	$ 221	$ 122
ETE	5,255	2,632
MEP	632	2,805
McReynolds Energy	-	202
Energy Transfer Technologies, Ltd.	-	16
Others	870	449
Total accounts receivable from related companies excluding Enterprise	$ 6,978	$ 6,226

Effective August 17, 2009, we acquired 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of our General Partner's general partner and the other of which is controlled by a member of ETP's management. In exchange, the former members acquired the right to receive (in cash or Common Units) future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG may receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

Prior to our acquisition of ETG in August 2009, our natural gas midstream and intrastate transportation and storage operations secured compression services from ETT. The terms of each arrangement to provide compression services were, in the opinion of independent directors of the General Partner, no more or less favorable than those available from other providers of compression services. During the years ended December 31, 2009 (through the ETG acquisition date) and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, we made payments totaling $3.4 million, $9.4 million, $0.8 million and $2.4 million, respectively, to ETG for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations.

The Chief Executive Officer ("CEO") of our General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. We recorded non-cash compensation expense and an offsetting capital contribution of $1.3 million ($0.5 million in salary and $0.8 million in accrued bonuses) for each of the years ended December 31, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

15. REPORTABLE SEGMENTS:

Our financial statements reflect four reportable segments, which conduct their business exclusively in the United States of America, as follows:

- natural gas operations:
  - intrastate transportation and storage
  - interstate transportation
  - midstream
- retail propane and other retail propane related operations

Segments below the quantitative thresholds are classified as "other." The components of the "other" classification have not met any of the quantitative thresholds for determining reportable segments. Management has included the wholesale propane and natural gas compression services operations in "other" for all periods presented in this report because such operations are not material.

Midstream and intrastate transportation and storage segment revenues and expenses include intersegment and intrasegment transactions, which are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

The volumes and results of operations data for fiscal year 2007 do not include the interstate operations for periods prior to Transwestern's acquisition on December 1, 2006.

See "Business Operations" in Note 1 for a description of the operations of each of our reportable segments.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general and administrative expenses, gains (losses) on disposal of assets, interest expense, equity in earnings (losses) from affiliates and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. We began allocating administration expenses from the Partnership to our Operating Companies using the Modified Massachusetts Formula Calculation ("MMFC") which is based on factors such as respective segments' gross margins, employee costs, and property and equipment.

The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the periods presented are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Costs allocated from ETP to operating subsidiaries:				
Midstream and intrastate transportation and storage operations	$ 15,776	$ 19,834	$ 6,761	$ 11,357
Interstate operations	4,922	5,750	2,613	4,388
Retail propane and other retail propane related operations	12,113	12,664	5,992	10,067
Total	$ 32,811	$ 38,248	$ 15,366	$ 25,812
Costs allocated from operating subsidiaries to ETP:				
Midstream and intrastate transportation and storage operations	$ 6,699	$ 10,649	$ 2,440	$ 5,221
Retail propane and other retail propane related operations	412	2,428	850	2,187
Total	$ 7,111	$ 13,077	$ 3,290	$ 7,408

The following tables present the financial information by segment for the following periods:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 1,773,528	$ 3,379,424	$ 929,357	$ 3,085,940
Intersegment revenues	618,016	2,255,180	325,044	829,992
	2,391,544	5,634,604	1,254,401	3,915,932
Interstate transportation - revenues from external customers	270,213	244,224	76,000	178,663
Midstream				
Revenues from external customers	2,060,451	4,029,508	826,835	2,121,289
Intersegment revenues	380,709	1,312,885	339,478	732,207
	2,441,160	5,342,393	1,166,313	2,853,496
Retail propane and other retail propane related - revenues from external customers	1,292,583	1,624,010	511,258	1,284,867
All other:				
Revenues from external customers	20,520	16,702	6,060	121,278
Intersegment revenues	1,145	-	-	-
	21,665	16,702	6,060	121,278
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)
Total revenues	$ 5,417,295	$ 9,293,868	$ 2,349,510	$ 6,792,037
Cost of products sold:				
Intrastate transportation and storage	$ 1,393,295	$ 4,467,552	$ 964,568	$ 3,137,712
Midstream	2,116,279	4,986,495	1,043,191	2,632,187
Retail propane and other retail propane related	596,002	1,038,722	325,158	759,634
All other	16,350	13,376	5,259	110,872
Eliminations	(999,870)	(3,568,065)	(664,522)	(1,562,199)
Total cost of products sold	$ 3,122,056	$ 6,938,080	$ 1,673,654	$ 5,078,206
Depreciation and amortization:				
Intrastate transportation and storage	$ 107,605	$ 84,701	$ 20,670	$ 56,145
Interstate transportation	48,297	37,790	12,305	27,972
Midstream	70,845	59,344	13,629	23,388
Retail propane and other retail propane related	83,476	79,717	24,537	70,833
All other	2,580	599	192	824
Total depreciation and amortization	$ 312,803	$ 262,151	$ 71,333	$ 179,162
Operating income (loss):				
Intrastate transportation and storage	$ 626,779	$ 718,348	$ 172,120	$ 488,098
Interstate transportation	138,233	124,676	29,657	95,650
Midstream	140,732	166,414	73,167	123,176
Retail propane and other retail propane related	229,229	114,564	46,747	124,263
All other	(8,658)	(1,531)	(628)	1,735
Selling general and administrative expenses not allocated to segments	1,292	(4,892)	2,571	(3,270)
Total operating income	$ 1,127,607	$ 1,117,579	$ 323,634	$ 829,652
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (394,274)	$ (265,701)	$ (66,298)	$ (175,563)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	(1,013)	31,032
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	2,157	9,306	(5,202)	2,019
Income tax expense	(12,777)	(6,680)	(10,789)	(13,658)
	(336,065)	(251,556)	(61,810)	(152,371)
Net income	$ 791,542	$ 866,023	$ 261,824	$ 677,281

	As of December 31, 2009	As of December 31, 2008	As of December 31, 2007	As of August 31, 2007
Total assets:				
Intrastate transportation and storage	$ 4,901,102	$ 4,642,430	$ 3,976,895	$ 3,534,013
Interstate transportation	3,313,837	2,487,078	1,834,941	1,653,363
Midstream	1,523,538	1,537,972	1,304,187	801,968
Retail propane and other retail propane related	1,784,353	1,810,953	1,778,426	1,593,863
All other	212,142	149,056	113,712	125,221
Total	$ 11,734,972	$ 10,627,489	$ 9,008,161	$ 7,708,428

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):				
Intrastate transportation and storage	$ 378,494	$ 993,886	$ 320,965	$ 827,859
Interstate transportation	99,341	720,186	167,343	1,345,637
Midstream	95,081	267,900	414,722	201,646
Retail propane and other retail propane related	62,953	130,358	47,553	65,125
All other	44,911	3,072	953	2,015
Total	$ 680,780	$ 2,115,402	$ 951,536	$ 2,442,282

16. QUARTERLY FINANCIAL DATA (UNAUDITED):

Summarized unaudited quarterly financial data is presented below. The sum of net income per Limited Partner unit by quarter does not equal the net income per limited partner unit for the year due to the computation of income allocation between the General Partner and Limited Partners and variations in the weighted average units outstanding used in computing such amounts. HOLP's and Titan's businesses are seasonal due to weather conditions in their service areas. Propane sales to residential and commercial customers are affected by winter heating season requirements, which generally results in higher operating revenues and net income during the period from October through March of each year and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Sales to commercial and industrial customers are less weather sensitive. ETC OLP's business is also seasonal due to the operations of ET Fuel System and the HPL System. We expect margin related to the HPL System operations to be higher during the periods from November through March of each year and lower during the periods from April through October of each year due to the increased demand for natural gas during the cold weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

2009:	Quarter Ended March 31	June 30	September 30	December 31	Total Year
Revenues	$ 1,630,100	$ 1,151,817	$ 1,129,596	$ 1,505,782	$ 5,417,295
Gross profit	670,961	525,824	451,448	647,006	2,295,239
Operating income	360,853	219,220	177,347	370,187	1,127,607
Net income	307,167	150,738	72,456	261,181	791,542
Limited Partners' interest in net income	216,877	63,559	(16,471)	162,215	426,180
Basic net income per limited partner unit	$ 1.37	$ 0.38	$ (0.10)	$ 0.92	$ 2.53
Diluted net income per limited partner unit	$ 1.37	$ 0.38	$ (0.10)	$ 0.91	$ 2.53

2008:	Quarter Ended March 31	June 30	September 30	December 31	Total Year
Revenues	$ 2,639,371	$ 2,653,476	$ 2,206,215	$ 1,794,806	$ 9,293,868
Gross profit	659,653	529,404	572,761	593,970	2,355,788
Operating income	373,486	225,829	260,508	257,756	1,117,579
Net income	328,335	165,674	221,048	150,966	866,023
Limited Partners' interest in net income	253,971	86,691	140,796	68,669	550,127
Basic net income per limited partner unit	$ 1.78	$ 0.61	$ 0.94	$ 0.45	$ 3.74
Diluted net income per limited partner unit	$ 1.77	$ 0.60	$ 0.94	$ 0.45	$ 3.74

For the three months ended September 30, 2009, distributions paid for the period exceeded net income by $177.0 million. Accordingly, the distributions paid to the General Partner, including incentive distributions, further exceeded net income, and as a result, a net loss was allocated to the Limited Partners for the period.

17. COMPARATIVE INFORMATION FOR THE FOUR MONTHS ENDED DECEMBER 31, 2007:

The unaudited financial information for the four month period ended December 31, 2006, contained herein is presented for comparative purposes only and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America. Certain financial statement amounts have been adjusted due to the adoption of new accounting standards in 2009. See Note 2.

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)
(unaudited)

	Four Months Ended December 31, 2007 As Adjusted	Four Months Ended December 31, 2006 As Adjusted
REVENUES:		
Natural gas operations	$ 1,832,192	$ 1,668,667
Retail propane	471,494	409,821
Other	45,824	83,978
Total revenues	2,349,510	2,162,466
COSTS AND EXPENSES:		
Cost of products sold - natural gas operations	1,343,237	1,382,473
Cost of products sold - retail propane	315,698	256,994
Cost of products sold - other	14,719	50,376
Operating expenses	221,757	173,365
Depreciation and amortization	71,333	48,767
Selling, general and administrative	59,132	40,603
Total costs and expenses	2,025,876	1,952,578
OPERATING INCOME	323,634	209,888
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(66,298)	(54,946)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other, net	1,061	2,158
INCOME BEFORE INCOME TAX EXPENSE	272,613	164,055
Income tax expense	10,789	3,120
NET INCOME	261,824	160,935
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	-	490
NET INCOME ATTRIBUTABLE TO PARTNERS	261,824	160,445
GENERAL PARTNER’S INTEREST IN NET INCOME	91,011	73,204
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 170,813	$ 87,241
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 1.24	$ 0.70
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	137,624,934	123,931,608
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 1.24	$ 0.70
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	138,013,366	124,229,968

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
(Dollars in thousands)
(unaudited)

	Four Months Ended December 31,	
	2007	2006
Net income	$ 261,824	$ 160,935
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17,269)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	21,626	152,653
Change in value of available-for-sale securities	(98)	(401)
	4,259	128,554
Comprehensive income	266,083	289,489
Less: Comprehensive income attributable to noncontrolling interest	-	490
Comprehensive income attributable to partners	$ 266,083	$ 288,999

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES:		
Net income	$ 261,824	$ 160,935
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	71,333	48,767
Amortization in interest expense	1,435	1,068
Provision for loss on accounts receivable	544	563
Non-cash unit-based compensation expense	8,114	4,385
Non-cash executive compensation	442	-
Deferred income taxes	1,003	(2,234)
Gain on disposal of assets	(14,310)	(2,212)
Distributions in excess of (less than) equity in earnings of affiliates, net	4,448	(4,743)
Other non-cash	(2,069)	(76)
Net change in operating assets and liabilities, net of acquisitions	(87,062)	214,457
Net cash provided by operating activities	245,702	420,910
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(337,092)	(67,089)
Capital expenditures	(651,228)	(336,473)
Contributions in aid of construction costs	3,493	4,984
Advances to and investment in affiliates	(32,594)	(953,247)
Proceeds from the sale of assets	21,478	7,644
Net cash used in investing activities	(995,943)	(1,344,181)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,741,547	1,667,810
Principal payments on debt	(1,062,272)	(1,737,788)
Net proceeds from issuance of Limited Partner Units	234,887	1,200,000
Capital contribution from General Partner	29	24,489
Distributions to partners	(175,977)	(125,774)
Debt issuance costs	(211)	(9,451)
Net cash provided by financing activities	738,003	1,019,286
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(12,238)	96,015
CASH AND CASH EQUIVALENTS, beginning of period	68,705	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 56,467	$ 122,056
NON-CASH INVESTING AND FINANCING ACTIVITIES SUPPLEMENTAL CASH FLOW INFORMATION:		
NON-CASH INVESTING ACTIVITIES:		
Capital expenditures accrued	$ 87,622	$ 13,294
NON-CASH FINANCING ACTIVITIES:		
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 3,896	$ 532,631
Issuance of common units in connection with certain acquisitions	$ 1,400	$ -
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest, net of interest capitalized	$ 51,465	$ 27,496
Cash paid during the period for income taxes	$ 9,009	$ 6,196

Exhibit 99.2

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 78,808	$ 68,183
Marketable securities	3,002	6,055
Accounts receivable, net of allowance for doubtful accounts of $6,378 and $6,338 as of June 30, 2010 and December 31, 2009, respectively	471,288	566,522
Accounts receivable from related companies	49,520	57,369
Inventories	231,057	389,954
Exchanges receivable	9,985	23,136
Price risk management assets	24	12,371
Other current assets	91,112	148,373
Total current assets	934,796	1,271,963
PROPERTY, PLANT AND EQUIPMENT	10,329,313	9,649,405
ACCUMULATED DEPRECIATION	(1,126,660)	(979,158)
	9,202,653	8,670,247
ADVANCES TO AND INVESTMENTS IN AFFILIATES	7,587	663,298
LONG-TERM PRICE RISK MANAGEMENT ASSETS	4,237	—
GOODWILL	773,745	745,505
INTANGIBLES AND OTHER ASSETS, net	433,072	383,959
Total assets	$ 11,356,090	$ 11,734,972

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 315,601	$ 358,997
Accounts payable to related companies	7,623	38,842
Exchanges payable	11,323	19,203
Price risk management liabilities	2,248	442
Accrued and other current liabilities	459,146	365,168
Current maturities of long-term debt	40,693	40,887
Total current liabilities	836,634	823,539
LONG-TERM DEBT, less current maturities	6,049,443	6,176,918
OTHER NON-CURRENT LIABILITIES	134,385	134,807
COMMITMENTS AND CONTINGENCIES (Note 13)		
PARTNERS' CAPITAL:		
General Partner	172,153	174,884
Limited Partners:		
Common Unitholders (180,136,652 and 179,274,747 units authorized, issued and outstanding at June 30, 2010 and December 31, 2009, respectively)	4,147,705	4,418,017
Class E Unitholders (8,853,832 units authorized, issued and outstanding – held by subsidiary and reported as treasury units)	—	—
Accumulated other comprehensive income	15,770	6,807
Total partners' capital	4,335,628	4,599,708
Total liabilities and partners' capital	$11,356,090	$ 11,734,972

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
REVENUES:				
Natural gas operations	$ 1,045,946	$ 948,233	$ 2,352,655	$ 2,060,188
Retail propane	197,147	179,770	730,586	667,677
Other	24,613	23,814	56,446	54,052
Total revenues	1,267,706	1,151,817	3,139,687	2,781,917
COSTS AND EXPENSES:				
Cost of products sold – natural gas operations	654,239	542,004	1,566,845	1,274,117
Cost of products sold – retail propane	110,282	78,070	415,263	298,292
Cost of products sold – other	6,336	5,919	13,614	12,723
Operating expenses	169,533	176,681	340,281	358,454
Depreciation and amortization	83,877	76,174	167,153	148,777
Selling, general and administrative	44,255	53,749	93,009	109,481
Total costs and expenses	1,068,522	932,597	2,596,165	2,201,844
OPERATING INCOME	199,184	219,220	543,522	580,073
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(103,014)	(100,680)	(207,976)	(182,725)
Equity in earnings of affiliates	4,072	1,673	10,253	2,170
Gains (losses) on disposal of assets	1,385	181	(479)	(245)
Gains on non-hedged interest rate derivatives	—	36,842	—	50,568
Allowance for equity funds used during construction	4,298	(1,839)	5,607	18,588
Impairment of investment in affiliate	(52,620)	—	(52,620)	—
Other, net	(5,893)	(100)	(4,860)	967
INCOME BEFORE INCOME TAX EXPENSE	47,412	155,297	293,447	469,396
Income tax expense	4,569	4,559	10,493	11,491
NET INCOME	42,843	150,738	282,954	457,905
GENERAL PARTNER’S INTEREST IN NET INCOME	90,599	87,179	190,598	177,469
LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS)	$ (47,756)	$ 63,559	$ 92,356	$ 280,436
BASIC NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ (0.26)	$ 0.38	$ 0.48	$ 1.72
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	186,649,074	166,596,074	187,531,919	161,829,139
DILUTED NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$ (0.26)	$ 0.38	$ 0.48	$ 1.72
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	186,649,074	167,197,121	188,362,188	162,384,831

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)
(unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income	$ 42,843	$ 150,738	$ 282,954	$ 457,905
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(6,112)	856	(12,618)	(9,693)
Change in value of derivative instruments accounted for as cash flow hedges	(9,452)	1,336	24,634	(50)
Change in value of available-for-sale securities	(724)	3,657	(3,053)	3,708
	(16,288)	5,849	8,963	(6,035)
Comprehensive income	$ 26,555	$ 156,587	$ 291,917	$ 451,870

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2010

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income	Total
Balance, December 31, 2009	$ 174,884	$ 4,418,017	$ 6,807	$4,599,708
Redemption of units in connection with MEP Transaction (See Note 1)	(3,700)	(608,340)	—	(612,040)
Distributions to partners	(198,573)	(340,061)	—	(538,634)
Units issued for cash	—	574,522	—	574,522
Capital contribution from General Partner (payment of contributions receivable)	8,932	—	—	8,932
Distributions on unvested unit awards	—	(2,264)	—	(2,264)
Tax effect of remedial income allocation from tax amortization of goodwill	—	(1,701)	—	(1,701)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	14,563	—	14,563
Non-cash executive compensation	12	613	—	625
Other comprehensive income	—	—	8,963	8,963
Net income	190,598	92,356	—	282,954
Balance, June 30, 2010	$ 172,153	$ 4,147,705	$ 15,770	$4,335,628

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 884,001	$ 702,680
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(153,385)	(6,362)
Capital expenditures (excluding allowance for equity funds used during construction)	(608,497)	(512,534)
Contributions in aid of construction costs	7,957	2,349
Advances to affiliates, net of repayments	(5,596)	(364,000)
Proceeds from the sale of assets	9,124	5,033
Net cash used in investing activities	(750,397)	(875,514)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	265,642	1,587,943
Principal payments on debt	(410,142)	(1,501,487)
Net proceeds from issuance of Limited Partner units	574,522	578,924
Capital contribution from General Partner	8,932	3,354
Distributions to partners	(538,634)	(465,827)
Redemption of units	(23,299)	—
Debt issuance costs	—	(7,746)
Net cash provided by (used in) financing activities	(122,979)	195,161
INCREASE IN CASH AND CASH EQUIVALENTS	10,625	22,327
CASH AND CASH EQUIVALENTS, beginning of period	68,183	91,902
CASH AND CASH EQUIVALENTS, end of period	$ 78,808	$ 114,229

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2009, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.P., and its subsidiaries ("Energy Transfer Partners," the "Partnership," "we" or "ETP") as of June 30, 2010 and for the three and six months ended June 30, 2010 and 2009, have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners, L.P. and its subsidiaries as of June 30, 2010, and the Partnership's results of operations and cash flows for the three and six months ended June 30, 2010 and 2009. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of Energy Transfer Partners presented in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009, as filed with the SEC on February 24, 2010.

Certain prior period amounts have been reclassified to conform to the 2010 presentation. These reclassifications had no impact on net income or total partners' capital.

We are managed by our general partner, Energy Transfer Partners GP, L.P. (our "General Partner" or "ETP GP"), which is in turn managed by its general partner, Energy Transfer Partners, L.L.C. ("ETP LLC"). Energy Transfer Equity, L.P., a publicly traded master limited partnership ("ETE"), owns ETP LLC, the general partner of our General Partner. The condensed consolidated financial statements of the Partnership presented herein include our operating subsidiaries described below.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the "Operating Companies") as follows:

- La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company ("ETC OLP"), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- Energy Transfer Interstate Holdings, LLC ("ET Interstate"), a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
    - Transwestern Pipeline Company, LLC ("Transwestern"), a Delaware limited liability company engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

    - ETC Fayetteville Express Pipeline, LLC (“ETC FEP”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.
    - ETC Tiger Pipeline, LLC (“ETC Tiger”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Compression, LLC (“ETC Compression”), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Heritage Operating, L.P. (“HOLP”), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan Energy Partners, L.P. (“Titan”), a Delaware limited partnership also engaged in retail propane operations.

Recent Developments

On May 26, 2010, we completed the transfer of the membership interests in ETC Midcontinent Express Pipeline III, L.L.C. (“ETC MEP III”) to ETE pursuant to the Redemption and Exchange Agreement between us and ETE, dated as of May 10, 2010 (the “MEP Transaction”). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC (“MEP”), our joint venture with Kinder Morgan Energy Partners, L.P. (“KMP”) that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, we redeemed 12,273,830 ETP common units that were previously owned by ETE. We also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. This closing adjustment is subject to change during a final review period as defined in the contribution agreement. We also granted ETE an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. (“ETC MEP II”). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of our interest in ETC MEP III, we recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP (“Regency”) in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc. (“GE EFS”).

We continue to guarantee 50% of MEP’s obligations under MEP’s $175.4 million senior revolving credit facility, with the remaining 50% of MEP’s obligations guaranteed by KMP; however, Regency has agreed to indemnify us for any costs related to the guaranty of payments under this facility. See Note 13.

2. <u>ESTIMATES:</u>

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream and intrastate transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the operating results estimated for the three and six months ended June 30, 2010 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

3. ACQUISITIONS:

During the six months ended June 30, 2010, we purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, we recorded customer contracts of $68.2 million and goodwill of $27.3 million. See further discussion at Note 6.

4. CASH, CASH EQUIVALENTS AND SUPPLEMENTAL CASH FLOW INFORMATION:

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

Net cash provided by operating activities is comprised of the following:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Net income	$ 282,954	$ 457,905
Reconciliation of net income to net cash provided by operating activities:		
Impairment of investment in affiliate	52,620	—
Proceeds from termination of interest rate derivatives	15,395	—
Depreciation and amortization	167,153	148,777
Amortization of finance costs charged to interest	4,381	4,152
Non-cash unit-based compensation expense	14,600	14,483
Non-cash executive compensation expense	625	625
Deferred income taxes	155	9,703
Losses on disposal of assets	479	245
Allowance for equity funds used during construction	(5,607)	(18,588)
Distributions on unvested awards	(2,264)	(1,387)
Distributions in excess of (less than) equity in earnings of affiliates, net	20,378	(430)
Other non-cash	1,118	2,167
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	96,767	200,132
Accounts receivable from related companies	7,849	(19,240)
Inventories	159,540	84,695
Exchanges receivable	13,151	17,613
Other current assets	57,263	47,206
Intangibles and other assets	3,615	(2,043)
Accounts payable	(51,622)	(108,183)
Accounts payable to related companies	(11,412)	(27,323)
Exchanges payable	(7,880)	(31,843)
Accrued and other current liabilities	35,925	25,954
Other non-current liabilities	(583)	(155)
Price risk management liabilities, net	29,401	(101,785)
Net cash provided by operating activities	$ 884,001	$ 702,680

Non-cash investing and financing activities are as follows:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 73,432	$ 90,268
Transfer of MEP joint venture interest in exchange for redemption of Common Units	$ 588,741	$ —
NON-CASH FINANCING ACTIVITIES:		
Capital contribution receivable from general partner	$ —	$ 8,932

5. INVENTORIES:

Inventories consisted of the following:

	June 30, 2010	December 31, 2009
Natural gas and NGLs, excluding propane	$ 89,751	$ 157,103
Propane	49,016	66,686
Appliances, parts and fittings and other	92,290	166,165
Total inventories	$ 231,057	$ 389,954

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. We designate commodity derivatives as fair value hedges for accounting purposes. Changes in fair value of the designated hedged inventory have been recorded in inventory on our condensed consolidated balance sheets and have been recorded in cost of products sold in our condensed consolidated statements of operations.

6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

A net increase in goodwill of $28.2 million was recorded during the six months ended June 30, 2010, primarily due to $27.3 million from the acquisition of the natural gas gathering company referenced in Note 3, which is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $68.2 million with useful lives of 46 years.

Components and useful lives of intangibles and other assets were as follows:

	June 30, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 245,574	$ (67,178)	$ 176,858	$ (58,761)
Noncompete agreements (3 to 15 years)	22,931	(12,578)	24,139	(12,415)
Patents (9 years)	750	(76)	750	(35)
Other (10 to 15 years)	1,320	(440)	478	(397)
Total amortizable intangible assets	270,575	(80,272)	202,225	(71,608)
Non-amortizable intangible assets — Trademarks	76,086	—	75,825	—
Total intangible assets	346,661	(80,272)	278,050	(71,608)
Other assets:				
Financing costs (3 to 30 years)	68,657	(29,104)	68,597	(24,774)
Regulatory assets	107,193	(12,508)	101,879	(9,501)
Other	32,445	—	41,316	—
Total intangibles and other assets	$ 554,956	$ (121,884)	$ 489,842	$ (105,883)

Aggregate amortization expense of intangible and other assets was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Reported in depreciation and amortization	$ 5,148	$ 4,983	$ 10,294	$ 9,692
Reported in interest expense	$ 2,165	$ 2,048	$ 4,330	$ 3,926

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2011	$ 26,915
2012	23,330
2013	17,899
2014	16,890
2015	14,566

7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at June 30, 2010 was $6.55 billion and $6.09 billion, respectively. At December 31, 2009, the aggregate fair value and carrying amount of long-term debt was $6.75 billion and $6.22 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (“OTC”) commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2010 and December 31, 2009 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2010 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 3,002	$ 3,002	$ —
Interest rate derivatives	7,031	—	7,031
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	24	—	24
Swing Swaps IFERC	1,425	1,425	—
Fixed Swaps/Futures	1,045	1,045	—
Options – Puts	19,241	—	19,241
Total commodity derivatives	21,735	2,470	19,265
Total Assets	$ 31,768	$ 5,472	$ 26,296
Liabilities:			
Interest rate derivatives	$ (205)	$ —	$ (205)
Commodity derivatives:			
Natural Gas:			
Basic Swaps IFERC/NYMEX	(454)	(454)	—
Swing Swaps IFERC	(167)	—	(167)
Fixed Swaps/Futures	(181)	—	(181)
Options – Calls	(6,142)	—	(6,142)
Propane – Forwards/Swaps	(4,489)	—	(4,489)
Total commodity derivatives	(11,433)	(454)	(10,979)
Total Liabilities	$ (11,638)	$ (454)	$ (11,184)

		Fair Value Measurements at December 31, 2009 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 6,055	$ 6,055	$ —
Commodity derivatives	32,479	20,090	12,389
Liabilities:			
Commodity derivatives	(8,016)	(7,574)	(442)
Total	$ 30,518	$ 18,571	$ 11,947

In conjunction with the MEP Transaction, we adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of our investment was transferred to ETE. See “Recent Developments” at Note 1.

8. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline, LLC

On May 26, 2010, we transferred to ETE, in exchange for ETP common units owned by ETE, substantially all of our interest in MEP. In conjunction with this transfer, we recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest to its estimated fair value. See discussion of the transaction in “Recent Developments” at Note 1.

Fayetteville Express Pipeline, LLC

We are party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Panola County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC (“FEP”), the entity formed to construct, own and operate this pipeline, received Federal Energy Regulatory Commission (“FERC”) approval of its application for authority to construct and operate this pipeline. The pipeline is expected to have an initial capacity of 2.0 Bcf/d and is expected to be in service by the end of 2010. As of June 30, 2010, FEP has secured binding commitments for a minimum of 10 years for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (“NGPL”) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

9. NET INCOME (LOSS) PER LIMITED PARTNER UNIT:

Our net income (loss) for partners’ capital and statement of operations presentation purposes is allocated to the General Partner and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to our General Partner, the holder of the incentive distribution rights (“IDRs”) pursuant to our partnership agreement, which are declared and paid following the close of each quarter. Earnings in excess of distributions are allocated to the General Partner and Limited Partners based on their respective ownership interests.

A reconciliation of net income and weighted average units used in computing basic and diluted net income per unit is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	$ 42,843	$ 150,738	$ 282,954	$ 457,905
General Partner’s interest in net income	90,599	87,179	190,598	177,469
Limited Partners’ interest in net income (loss)	(47,756)	63,559	92,356	280,436
Additional earnings allocated (to) from General Partner	(161)	—	636	—
Distributions on employee unit awards, net of allocation to General Partner	(1,152)	(651)	(2,309)	(1,349)
Net income (loss) available to Limited Partners	$ (49,069)	$ 62,908	$ 90,683	$ 279,087
Weighted average Limited Partner units – basic	186,649,074	166,596,074	187,531,919	161,829,139
Basic net income (loss) per Limited Partner unit	$ (0.26)	$ 0.38	$ 0.48	$ 1.72
Weighted average Limited Partner units	186,649,074	166,596,074	187,531,919	161,829,139
Dilutive effect of unit grants	—	601,047	830,269	555,692
Weighted average Limited Partner units, assuming dilutive effect of Unit Grants	186,649,074	167,197,121	188,362,188	162,384,831
Diluted net income (loss) per Limited Partner unit	$ (0.26)	$ 0.38	$ 0.48	$ 1.72

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended June 30, 2010 are expected to be $256.2 million in total, which exceeds net income for the period by $213.3 million. Accordingly, the distributions expected to be paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended June 30, 2010, and as a result, a net loss was allocated to the Limited Partners for the period.

10. DEBT OBLIGATIONS:

Revolving Credit Facilities

ETP Credit Facility

We maintain a revolving credit facility (the “ETP Credit Facility”) that provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of June 30, 2010, there was $29.3 million of borrowings outstanding under the ETP Credit Facility. Taking into account letters of credit of approximately $21.8 million, the amount available for future borrowings was $1.95 billion. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 0.95%.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility. At June 30, 2010, the HOLP credit facility had no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of June 30, 2010 was $74.5 million.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at June 30, 2010.

11. PARTNERS' CAPITAL:

Common Units Issued

The change in Common Units during the six months ended June 30, 2010 was as follows:

	Number of Units
Balance, December 31, 2009	179,274,747
Common Units issued in connection with public offerings	9,775,000
Common Units issued in connection with the Equity Distribution Agreement	3,340,783
Issuance of Common Units under equity incentive plans	19,952
Redemption of units in connection with MEP Transaction (See Note 1)	(12,273,830)
Balance, June 30, 2010	180,136,652

In January 2010, we issued 9,775,000 Common Units through a public offering. The proceeds of $423.6 million from the offering were used primarily to repay borrowings under the ETP Credit Facility and to fund capital expenditures related to pipeline projects.

On August 26, 2009, we entered into an Equity Distribution Agreement with UBS Securities LLC ("UBS"). Pursuant to this agreement, we may offer and sell from time to time through UBS, as our sales agent, Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between us and UBS. Under the terms of this agreement, we may also sell Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of Common Units to UBS as principal would be pursuant to the terms of a separate agreement between us and UBS. During the six months ended June 30, 2010, we issued 3,340,783 of our Common Units pursuant to this agreement. The proceeds of approximately $151.0 million, net of commissions, were used for general partnership purposes. In addition, we initiated trades on an additional 501,500 of our Common Units that had not settled as of June 30, 2010. Approximately $40.6 million of our Common Units remain available to be issued under the agreement based on trades initiated through June 30, 2010.

Quarterly Distributions of Available Cash

Distributions paid by us are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2009	February 8, 2010	February 15, 2010	$0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at the close of business on August 9, 2010.

The total amounts of distributions declared during the six months ended June 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30,	
	2010	2009
Limited Partners:		
Common Units	$ 332,371	$ 301,738
Class E Units	6,242	6,242
General Partner Interest	9,754	9,720
Incentive Distribution Rights	184,751	168,311
Total distributions declared by ETP	$ 533,118	$ 486,011

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income (“AOCI”), net of tax:

	June 30, 2010	December 31, 2009
Net gains on commodity related hedges	$ 14,353	$ 1,991
Net losses on interest rate hedges	(471)	(125)
Unrealized gains on available-for-sale securities	1,888	4,941
Total AOCI, net of tax	$ 15,770	$ 6,807

12. INCOME TAXES:

The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Current expense (benefit):				
Federal	$ 1,599	$ (771)	$ 2,917	$ (5,107)
State	4,248	3,377	7,421	6,895
Total	5,847	2,606	10,338	1,788
Deferred expense (benefit):				
Federal	(997)	2,041	421	9,142
State	(281)	(88)	(266)	561
Total	(1,278)	1,953	155	9,703
Total income tax expense	$ 4,569	$ 4,559	$ 10,493	$ 11,491
Effective tax rate	9.64%	2.94%	3.58%	2.45%

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level.

13. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, we filed an application for FERC authority to construct and operate the Tiger pipeline. The application was approved in April 2010 and construction began in June 2010. In February 2010, we announced a 400 MMcf/d expansion of the Tiger pipeline. In June 2010, we filed an application for FERC authority to construct, own and operate that expansion.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act ("NGA") proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern's tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

Guarantees

MEP Guarantee

We have guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the "MEP Facility"), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although we transferred substantially all of our interest in MEP on May 26, 2010, as discussed above in "Recent Developments" at Note 1, we will continue to guarantee 50% of MEP's obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify us for any costs related to the guarantee of payments under this facility.

Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP's ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of June 30, 2010, MEP had $33.1 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility, respectively. Our contingent obligations with respect to our 50% guarantee of MEP's outstanding borrowings and letters of credit were $16.6 million and $16.6 million, respectively, as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 1.4%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the "FEP Facility"). We have guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012 and amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 1.0%.

As of June 30, 2010, FEP had $663.0 million of outstanding borrowings issued under the FEP Facility and our contingent obligation with respect to our 50% guarantee of FEP's outstanding borrowings was $331.5 million as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts. In addition, we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a contract to purchase not less than 90.0 million gallons of propane per year that expires in 2015. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.4 million and $5.5 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, rental expense for operating leases totaled approximately $11.3 million and $11.5 million, respectively.

Our propane operations have an agreement with Enterprise GP Holdings L.P. ("Enterprise") (see Note 15) to supply a portion of our propane requirements. The agreement expired in March 2010 and our propane operations executed a five year extension as of April 2010. The extension will continue until March 2015 and includes an option to extend the agreement for an additional year.

We have commitments to make capital contributions to our joint ventures. For the joint ventures that we currently have interests in, we expect that capital contributions for the remainder of 2010 will be between $20 million and $30 million.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

FERC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the "Order and Notice") that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC's then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP's trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against us by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ's recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ's fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, ETP remains a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The Plaintiff appealed this determination to the First Court of

Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010, the First Circuit Court of Appeals issued an opinion affirming the judgment of the lower court granting ETP's motion for summary judgment. No motion for rehearing was timely filed.

In October 2007, a consolidated class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint. No petition for rehearing was timely filed.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted our motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obligated to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations and our liquidity.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were defendants in litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the "Cushion Gas Litigation." In 2004, ETC OLP (a subsidiary of ETP) acquired the HPL Entities from AEP, at which time AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A under this court decision.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of June 30, 2010 and December 31, 2009, accruals of approximately $11.4 million and $11.1 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

No amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters and deductibles.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that can require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline, gathering, treating, compressing, blending and processing business. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage, and to limit the financial liability, which could result from such events. However, the risk of environmental or other damage is inherent in the transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products , as it is with other entities engaged in similar businesses.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in clean-up technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of June 30, 2010 and December 31, 2009, accruals on an undiscounted basis of $12.5 million and $12.6 million, respectively, were recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for clean-up costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean-up activities include remediation of several compressor sites on the Transwestern system for historical contamination associated with polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.5 million, which is included in the aggregate environmental accruals. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the U.S. Environmental Protection Agency’s (the “EPA”) Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

By March 2013, the Texas Commission on Environmental Quality is required to develop another plan to address the recent change in the ozone standard from 0.08 parts per million, or ppm, to 0.075 ppm and the U.S. Environmental Protection Agency, or EPA, recently proposed lowering the standard even further, to somewhere in between 0.06 and 0.07 ppm. These efforts may result in the adoption of new regulations that may require additional nitrogen oxide emissions reductions.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation (“DOT”) under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended June 30, 2010 and 2009, $3.6 million and $11.6 million, respectively, of capital costs and $4.4 million and $5.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the six months ended June 30, 2010 and 2009, $5.0 million and $15.3 million, respectively, of capital costs and $6.3 million and $9.0 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act, also known as OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA’s hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our segments as follows:

- Derivatives are utilized in our midstream segment in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage and interstate segments to hedge the sales price of retention and operational gas sales and hedge location price differentials related to the transportation of natural gas.
- Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread, through either mark-to-market or the physical withdrawal of natural gas.

The recent adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Part II, Item 1A. Risk Factors of this Form 10-Q.

We are also exposed to market risk on gas we retain for fees in our intrastate transportation and storage segment and operational gas sales on our interstate transportation segment. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

The following table details the outstanding commodity-related derivatives:

	June 30, 2010		December 31, 2009	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(23,182,500)	2010-2011	72,325,000	2010-2011
Swing Swaps IFERC (MMBtu)	(23,592,500)	2010-2011	(38,935,000)	2010
Fixed Swaps/Futures (MMBtu)	(395,000)	2010-2011	4,852,500	2010-2011
Options – Puts (MMBtu)	(8,140,000)	2010-2011	2,640,000	2010
Options – Calls (MMBtu)	(5,920,000)	2010-2011	(2,640,000)	2010
Propane:				
Forwards/Swaps (Gallons)	—	—	6,090,000	2010
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(5,410,000)	2010-2011	(22,625,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,765,000)	2010-2011	(27,300,000)	2010
Hedged Item – Inventory (MMBtu)	18,765,000	2010	27,300,000	2010
Cash Flow Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(10,845,000)	2010-2011	(13,225,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,502,500)	2010-2011	(22,800,000)	2010
Options – Puts (MMBtu)	25,800,000	2011-2012	—	—
Options – Calls (MMBtu)	(25,800,000)	2011-2012	—	—
Propane:				
Forwards/Swaps (Gallons)	51,702,000	2010-2011	20,538,000	2010

We expect gains of $11.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps in order to achieve our desired mix of fixed and variable rate debt. We also utilize interest rate swaps to lock in the rate on a portion of our anticipated debt issuances. We have the following interest rate swaps outstanding as of June 30, 2010:

Term	Notional Amount	Type [(1)]	Hedge Designation
July 2013	$350,000	Pay a floating rate plus 3.75% and receive a fixed rate of 6.00%	Fair value
August 2012	200,000	Forward starting to pay a fixed rate of 3.80% and receive a floating rate	Cash flow

(1) Floating rates are based on LIBOR.

In May 2010, the Partnership terminated interest rate swaps with notional amounts of $750.0 million that were designated as fair value hedges. Proceeds from the swap termination were $15.4 million. In connection with the swap termination, $9.7 million of previously recorded fair value adjustments to the hedged long-term debt will be amortized as a reduction of interest expense through February 2015.

Derivative Summary

The following table provides a balance sheet overview of the Partnership’s derivative assets and liabilities as of June 30, 2010 and December 31, 2009:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2010	December 31, 2009	June 30, 2010	December 31, 2009
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$25,158	$ 669	$ (4,425)	$ (24,035)
Commodity derivatives	—	8,443	(4,625)	(201)
Interest rate derivatives	7,031	—	(205)	—
	32,189	9,112	(9,255)	(24,236)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	32,257	72,851	(37,877)	(36,950)
Commodity derivatives	24	3,928	(212)	(241)
	32,281	76,779	(38,089)	(37,191)
Total derivatives	$64,470	$ 85,891	$(47,344)	$ (61,427)

The commodity derivatives (margin deposits) are recorded in “Other current assets” on our condensed consolidated balance sheets. The remainder of the derivatives are recorded in “Price risk management assets/liabilities.”

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our condensed consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the condensed consolidated balance sheets. The Partnership had net deposits with counterparties of $44.4 million and $79.7 million as of June 30, 2010 and December 31, 2009, respectively.

The following tables detail the effect of the Partnership's derivative assets and liabilities in the condensed consolidated statements of operations for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$ (9,150)	$ 1,336	$ 24,957	$ (50)
Interest rate derivatives	(205)	—	(205)	—
Total	$ (9,355)	$ 1,336	$ 24,752	$ (50)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ 7,058	$ (928)	$12,373	$ 9,549
Interest rate derivatives	Interest expense	71	72	142	144
Total		$ 7,129	$ (856)	$12,515	$ 9,693

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ (1,016)	$ —	$ 105	$ —
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ (1,016)	$ —	$ 105	$ —

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 6,417	$ 12,498	$ (967)	$12,498
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ 6,417	$ 12,498	$ (967)	$12,498

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$ (21,295)	$ 5,138	$ 672	$ 56,576
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	—	36,842	—	50,568
Total		$ (21,295)	$ 41,980	$ 672	$ 107,144

We recognized $36.5 million and $27.0 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended June 30, 2010 and 2009, respectively. We recognized $45.2 million and $46.1 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the six months ended June 30, 2010 and 2009, respectively.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our condensed consolidated balance sheet and recognized in net income or other comprehensive income.

15. RELATED PARTY TRANSACTIONS:

As discussed in “Recent Developments” in Note 1, Regency became a related party on May 26, 2010. Regency provides us with contract compression services. For the period from May 26, 2010 to June 30, 2010, we recorded costs of products sold of $0.7 million and operating expenses of $0.2 million related to transactions with Regency.

We and subsidiaries of Enterprise transport natural gas on each other’s pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. The following table presents sales to and purchase from affiliates of Enterprise:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Natural Gas Operations:				
Sales	$ 130,526	$ 90,591	$ 275,246	$ 165,074
Purchases	6,936	2,688	13,533	16,346
Propane Operations:				
Sales	481	5,226	10,966	11,508
Purchases	52,415	41,005	218,179	176,223

Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that was extended until March 2015, and includes an option to extend the agreement for an additional year. As of December 31, 2009, Titan had forward mark-to-market derivatives for approximately 6.1 million gallons of propane at a fair value asset of $3.3 million with Enterprise. All of these forward contracts were settled as of June 30, 2010. In addition, as of June 30, 2010 and December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 51.7 million and 20.5 million gallons of propane at a fair value liability of $4.5 million and a fair value asset of $8.4 million, respectively, with Enterprise.

The following table summarizes the related party balances on our condensed consolidated balance sheets:

	June 30, 2010	December 31, 2009
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$ 41,451	$ 47,005
Propane Operations	181	3,386
Other	7,888	6,978
Total accounts receivable from related parties:	$ 49,520	$ 57,369
Accounts payable from related parties:		
Enterprise:		
Natural Gas Operations	$ 825	$ 3,518
Propane Operations	5,478	31,642
Other	1,320	3,682
Total accounts payable from related parties:	$ 7,623	$ 38,842

The net imbalance payable from Enterprise was $1.9 million and $0.7 million for June 30, 2010 and December 31, 2009, respectively.

16. OTHER INFORMATION:

The tables below present additional detail for certain balance sheet captions.

Other Current Assets

Other current assets consisted of the following:

	June 30, 2010	December 31, 2009
Deposits paid to vendors	$44,393	$ 79,694
Prepaid and other	46,719	68,679
Total other current assets	$91,112	$ 148,373

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2010	December 31, 2009
Interest payable	$133,314	$ 136,222
Customer advances and deposits	69,591	88,430
Accrued capital expenditures	73,432	46,134
Accrued wages and benefits	40,272	25,202
Taxes other than income taxes	72,041	23,294
Income taxes payable	9,811	3,401
Deferred income taxes	109	—
Other	60,576	42,485
Total accrued and other current liabilities	$459,146	$ 365,168

17. REPORTABLE SEGMENTS:

Our financial statements reflect four reportable segments, which conduct their business exclusively in the United States of America, as follows:

- natural gas operations consisting of:
  - intrastate transportation and storage;
  - interstate transportation; and
  - midstream.
- retail propane and other retail propane related operations

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general and administrative expenses. The following tables present the financial information by segment for the following periods:

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Revenues:				
Intrastate transportation and storage:				
Revenues from external customers	$ 530,174	$ 372,674	$ 1,132,530	$ 828,477
Intersegment revenues	318,713	121,260	582,849	294,108
	848,887	493,934	1,715,379	1,122,585
Interstate transportation – revenues from external customers	70,079	70,585	138,348	131,934
Midstream:				
Revenues from external customers	407,123	504,973	1,025,830	1,099,776
Intersegment revenues	350,671	40,795	528,735	77,624
	757,794	545,768	1,554,565	1,177,400
Retail propane and other retail propane related – revenues from external customers	220,126	202,272	781,281	718,184
All other:				
Revenues from external customers	40,204	1,313	61,698	3,546
Intersegment revenues	935	—	2,381	—
	41,139	1,313	64,079	3,546
Eliminations – against operating expenses	(84)	—	(168)	—
Eliminations – against cost of products sold	(670,235)	(162,055)	(1,113,797)	(371,732)
Total revenues	$ 1,267,706	$ 1,151,817	$ 3,139,687	$ 2,781,917
Cost of products sold:				
Intrastate transportation and storage	$ 629,185	$ 233,951	$ 1,270,691	$ 616,565
Midstream	662,564	470,108	1,362,356	1,029,284
Retail propane and other retail propane related	115,133	82,886	424,890	307,991
All other	34,210	1,103	51,582	3,024
Eliminations	(670,235)	(162,055)	(1,113,797)	(371,732)
Total cost of products sold	$ 770,857	$ 625,993	$ 1,995,722	$ 1,585,132
Depreciation and amortization:				
Intrastate transportation and storage	$ 29,152	$ 25,859	$ 58,144	$ 50,892
Interstate transportation	12,762	12,837	25,213	23,496
Midstream	20,282	17,191	40,617	33,701
Retail propane and other retail propane related	20,297	20,174	40,385	40,446
All other	1,384	113	2,794	242
Total depreciation and amortization	$ 83,877	$ 76,174	$ 167,153	$ 148,777

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Operating income (loss):				
Intrastate transportation and storage	$ 127,818	$ 156,929	$ 262,022	$ 300,644
Interstate transportation	32,165	31,950	63,762	60,145
Midstream	49,865	28,050	102,197	53,189
Retail propane and other retail propane related	(6,436)	4,560	120,338	168,629
All other	(231)	(1,016)	(1,362)	(1,782)
Selling, general and administrative expenses not allocated to segments	(3,997)	(1,253)	(3,435)	(752)
Total operating income	$ 199,184	$ 219,220	$ 543,522	$ 580,073
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$ (103,014)	$ (100,680)	$ (207,976)	$ (182,725)
Equity in earnings of affiliates	4,072	1,673	10,253	2,170
Gains (losses) on disposal of assets	1,385	181	(479)	(245)
Gains on non-hedged interest rate derivatives	—	36,842	—	50,568
Allowance for equity funds used during construction	4,298	(1,839)	5,607	18,588
Impairment of investment in affiliate	(52,620)	—	(52,620)	—
Other income, net	(5,893)	(100)	(4,860)	967
Income tax expense	(4,569)	(4,559)	(10,493)	(11,491)
	(156,341)	(68,482)	(260,568)	(122,168)
Net income	$ 42,843	$ 150,738	$ 282,954	$ 457,905

	As of June 30, 2010	As of December 31, 2009
Total assets:		
Intrastate transportation and storage	$ 4,839,267	$ 4,901,102
Interstate transportation	2,966,334	3,313,837
Midstream	1,644,369	1,523,538
Retail propane and other retail propane related	1,681,801	1,784,353
All other	224,319	212,142
Total	$ 11,356,090	$ 11,734,972

	Six Months Ended June 30,	
	2010	2009
Additions to property, plant and equipment including acquisitions, net of contributions in aid of construction costs (accrual basis):		
Intrastate transportation and storage	$ 46,104	$ 306,096
Interstate transportation	428,978	63,955
Midstream	188,246	54,610
Retail propane and other retail propane related	30,404	33,228
All other	4,426	3,003
Total	$ 698,158	$ 460,892

Exhibit 99.3

Report of Independent Registered Public Accounting Firm

Partners
Energy Transfer Partners GP, L.P.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners GP, L.P. (a Delaware limited partnership) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Partners GP, L.P. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Partnership retrospectively adopted a new accounting pronouncement on January 1, 2009 related to the accounting for noncontrolling interests in consolidated financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
August 9, 2010

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 68,253	$ 91,962
Marketable securities	6,055	5,915
Accounts receivable, net of allowance for doubtful accounts	566,522	591,257
Accounts receivable from related companies	57,148	17,773
Inventories	389,954	272,348
Exchanges receivable	23,136	45,209
Price risk management assets	12,371	5,423
Other current assets	148,423	153,513
Total current assets	1,271,862	1,183,400
PROPERTY, PLANT AND EQUIPMENT, net	8,670,247	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	663,298	10,110
GOODWILL	775,093	773,282
INTANGIBLES AND OTHER ASSETS, net	384,109	394,399
Total assets	$11,764,609	$10,657,276

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 358,997	$ 381,135
Accounts payable to related companies	38,842	34,551
Exchanges payable	19,203	54,636
Price risk management liabilities	442	94,978
Interest payable	136,229	106,265
Accrued and other current liabilities	228,946	433,794
Current maturities of long-term debt	40,923	45,232
Total current liabilities	823,582	1,150,591
LONG-TERM DEBT, less current maturities	6,177,046	5,618,715
DEFERRED INCOME TAXES	112,997	100,597
OTHER NON-CURRENT LIABILITIES	21,810	14,727
COMMITMENTS AND CONTINGENCIES (Note 10)		
	7,135,435	6,884,630
EQUITY:		
PARTNERS' CAPITAL:		
General partner	18	16
Limited partners:		
Class A Limited Partner interests	107,515	92,313
Class B Limited Partner interests	96,638	98,227
Accumulated other comprehensive income	129	58
Total partners' capital	204,300	190,614
Noncontrolling interest	4,424,874	3,582,032
Total equity	4,629,174	3,772,646
Total liabilities and equity	$11,764,609	$10,657,276

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
REVENUES:				
Natural gas operations	$4,115,806	$7,653,156	$1,832,192	$5,385,892
Retail propane	1,190,524	1,514,599	471,494	1,179,073
Other	110,965	126,113	45,824	227,072
Total revenues	5,417,295	9,293,868	2,349,510	6,792,037
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	2,519,575	5,885,982	1,343,237	4,207,700
Cost of products sold - retail propane	574,854	1,014,068	315,698	734,204
Cost of products sold - other	27,627	38,030	14,719	136,302
Operating expenses	680,893	781,831	221,757	559,600
Depreciation and amortization	312,803	262,151	71,333	179,162
Selling, general and administrative	173,954	194,227	59,167	145,516
Total costs and expenses	4,289,706	8,176,289	2,025,911	5,962,484
OPERATING INCOME	1,127,589	1,117,579	323,599	829,553
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(394,371)	(265,718)	(66,304)	(175,582)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	(1,013)	31,032
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	1,835	9,169	(5,198)	2,035
INCOME BEFORE INCOME TAX EXPENSE	803,882	872,549	272,576	690,837
Income tax expense	12,777	6,680	10,789	13,658
NET INCOME	791,105	865,869	261,787	677,179
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	426,180	550,128	170,812	441,405
NET INCOME ATTRIBUTABLE TO PARTNERS	364,925	315,741	90,975	235,774
GENERAL PARTNER'S INTEREST IN NET INCOME	36	32	9	24
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 364,889	$ 315,709	$ 90,966	$ 235,750

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income	$ 791,105	$ 865,869	$ 261,787	$ 677,179
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(10,211)	(34,901)	(17,269)	(160,420)
Change in value of derivative instruments accounted for as cash flow hedges	3,182	17,326	21,626	175,720
Change in value of available-for-sale securities	10,923	(6,418)	(98)	280
	3,894	(23,993)	4,259	15,580
Comprehensive income	794,999	841,876	266,046	692,759
Less: Comprehensive income attributable to noncontrolling interest	430,003	526,615	174,986	456,674
Comprehensive income attributable to partners	$ 364,996	$ 315,261	$ 91,060	$ 236,085

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(Dollars in thousands)

	General Partner	Limited Partners	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, August 31, 2006	$ 11	$ 111,982	$ 142	$ 1,656,307	$1,768,442
Distributions to partners	(21)	(205,627)	—	—	(205,648)
Subsidiary distributions	—	—	—	(406,778)	(406,778)
Subsidiary issuance of units	—	—	—	1,200,000	1,200,000
Tax effect of remedial income allocation from tax amortization of goodwill	—	—	—	(1,161)	(1,161)
Non-cash unit-based compensation expense	—	—	—	10,471	10,471
Other comprehensive income, net of tax	—	—	311	15,269	15,580
Other	—	—	—	(760)	(760)
Net income	24	235,750	—	441,405	677,179
Balance, August 31, 2007	14	142,105	453	2,914,753	3,057,325
Distributions to partners	(6)	(59,310)	—	—	(59,316)
Subsidiary distributions	—	—	—	(113,080)	(113,080)
Subsidiary issuance of units	—	—	—	236,287	236,287
Tax effect of remedial income allocation from tax amortization of goodwill	—	—	—	(1,161)	(1,161)
Non-cash executive compensation	—	—	—	1,167	1,167
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	—	—	7,950	7,950
Other comprehensive income, net of tax	—	—	85	4,174	4,259
Sale of noncontrolling interest and other	—	—	—	(2,239)	(2,239)
Net income	9	90,966	—	170,812	261,787
Balance, December 31, 2007	17	173,761	538	3,218,663	3,392,979
Distributions to partners	(33)	(298,978)	—	—	(299,011)
Subsidiary distributions	—	—	—	(556,295)	(556,295)
Subsidiary issuance of units	—	—	—	375,287	375,287
Tax effect of remedial income allocation from tax amortization of goodwill	—	—	—	(3,407)	(3,407)
Non-cash executive compensation	—	48	—	1,202	1,250
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	—	—	19,967	19,967
Other comprehensive income, net of tax	—	—	(480)	(23,513)	(23,993)
Net income	32	315,709	—	550,128	865,869
Balance, December 31, 2008	16	190,540	58	3,582,032	3,772,646
Distributions to partners	(34)	(351,301)	—	—	(351,335)
Subsidiary distributions	—	—	—	(604,913)	(604,913)
Subsidiary issuance of units	—	—	—	999,676	999,676
Tax effect of remedial income allocation from tax amortization of goodwill	—	—	—	(3,762)	(3,762)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	—	—	20,613	20,613
Non-cash executive compensation	—	25	—	1,225	1,250
Other comprehensive income, net of tax	—	—	71	3,823	3,894
Net income	36	364,889	—	426,180	791,105
Balance, December 31, 2009	$ 18	$ 204,153	$ 129	$ 4,424,874	$4,629,174

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 791,105	$ 865,869	$ 261,787	$ 677,179
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	312,803	262,151	71,333	179,162
Amortization of finance costs charged to interest	8,645	5,886	1,435	4,061
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Goodwill impairment	—	11,359	—	—
Non-cash unit-based compensation expense	24,032	23,481	8,114	10,471
Non-cash executive compensation expense	1,250	1,250	442	—
Deferred income taxes	11,966	(5,280)	1,003	(4,042)
(Gains) losses on disposal of assets	1,564	1,303	(14,310)	6,310
Distributions in excess of (less than) equity in earnings of affiliates, net	3,224	5,621	4,448	(5,161)
Other non-cash	(4,468)	3,382	(2,069)	(761)
Net change in operating assets and liabilities, net of effects of acquisitions	(323,844)	59,207	(90,574)	255,697
Net cash provided by operating activities	829,269	1,242,244	242,153	1,127,145
CASH FLOWS FROM INVESTING ACTIVITIES:				
Net cash (paid for) received in acquisitions	30,367	(84,783)	(337,092)	(90,695)
Capital expenditures	(748,621)	(2,054,806)	(651,228)	(1,107,127)
Contributions in aid of construction costs	6,453	50,050	3,493	10,463
(Advances to) repayments from affiliates, net	(655,500)	54,534	(32,594)	(993,866)
Proceeds from the sale of assets	21,545	19,420	21,478	23,135
Net cash used in investing activities	(1,345,756)	(2,015,585)	(995,943)	(2,158,090)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	3,475,107	6,015,461	1,741,547	4,757,971
Principal payments on debt	(2,954,771)	(4,699,154)	(1,062,272)	(4,260,523)
Subsidiary equity offerings, net of issue costs	936,337	373,059	234,887	1,200,000
Distributions to partners	(351,335)	(299,011)	(59,316)	(205,648)
Distributions to noncontrolling interests	(604,913)	(556,295)	(113,080)	(406,778)
Debt issuance costs	(7,647)	(25,272)	(211)	(11,397)
Net cash provided by financing activities	492,778	808,788	741,555	1,073,625
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(23,709)	35,447	(12,235)	42,680
CASH AND CASH EQUIVALENTS, beginning of period	91,962	56,515	68,750	26,070
CASH AND CASH EQUIVALENTS, end of period	$ 68,253	$ 91,962	$ 56,515	$ 68,750

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

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners GP, L.P. ("ETP GP" or "the Partnership") was formed in August 2000 as a Delaware limited partnership. ETP GP is the General Partner and the owner of the general partner interest of Energy Transfer Partners, L.P., a publicly-traded master limited partnership ("ETP"). ETP GP is owned 99.99% by its limited partners, and 0.01% by its general partner, Energy Transfer Partners, L.L.C ("ETP LLC").

Energy Transfer Equity, L.P. ("ETE") is the 100% owner of ETP LLC and also owns 100% of our Class A and Class B Limited Partner interests. For more information on our Class A and Class B Limited Partner interest, see Note 6.

Financial Statement Presentation

The consolidated financial statements of ETP GP and subsidiaries presented herein for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We consolidate all majority-owned and controlled subsidiaries. We present equity and net income attributable to noncontrolling interest for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through August 9, 2010, the date the financial statements were available to be issued.

The consolidated financial statements of the Partnership presented herein include our controlled subsidiary, ETP, and its wholly-owned subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company ("ETC OLP"); Energy Transfer Interstate Holdings, LLC ("ET Interstate"), the parent company of Transwestern Pipeline Company, LLC ("Transwestern") and ETC Midcontinent Express Pipeline, LLC ("ETC MEP"); ETC Fayetteville Express Pipeline, LLC ("ETC FEP"); ETC Tiger Pipeline, LLC ("ETC Tiger"); Heritage Operating, L.P. ("HOLP"); Heritage Holdings, Inc. ("HHI"); and Titan Energy Partners, L.P. ("Titan"). The operations of ET Interstate are included since the date of the Transwestern acquisition on December 1, 2006. ETC FEP and ETC Tiger are included since their inception dates on August 27, 2008 and June 20, 2008, respectively. The operations of all other subsidiaries listed above are reflected for all periods presented.

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

In November 2007, we changed our fiscal year end to the calendar year. Thus, a new fiscal year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007. The financial statements contained herein cover the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007.

We did not recast the financial data for the prior fiscal periods because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the years ended December 31, 2009 and 2008 are substantially similar to what is reflected in the information for the year ended August 31, 2007.

Certain prior period amounts have been reclassified to conform to the 2009 presentation. Other than the reclassifications related to the adoption of Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51*, which is now incorporated into ASC 810-10-65 (see Note 2), these reclassifications had no impact on net income or total equity.

Business Operations

In order to simplify the obligations of ETP under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the "Operating Companies") as follows:

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, Arizona, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- ET Interstate, the parent company of Transwestern and ETC MEP, both of which are Delaware limited liability companies engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- HOLP, a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan, a Delaware limited partnership also engaged in retail propane operations.

The Partnership, ETP, the Operating Companies and their subsidiaries are collectively referred to in this report as "we," "us," "our," "ETP," "Energy Transfer" or the "Partnership."

ETC OLP owns an interest in and operates approximately 14,800 miles of in service natural gas gathering and intrastate transportation pipelines, three natural gas processing plants, eleven natural gas treating facilities, eleven natural gas conditioning facilities and three natural gas storage facilities located in Texas.

Revenue in our intrastate transportation and storage operations is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The intrastate transportation and storage operations also consist of the HPL System, which generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System also transports natural gas for a variety of third party customers. Our intrastate transportation and storage operations also generate revenues from fees charged for storing customers' working natural gas in our storage facilities. In addition, the use of the Bammel storage facility allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin.

Our interstate transportation operations principally focus on natural gas transportation of Transwestern, which owns and operates approximately 2,700 miles of interstate natural gas pipeline, with an additional 180 miles under construction, extending from Texas through the San Juan Basin to the California border. In addition, we have interests in joint ventures that have 500 miles of interstate natural gas pipeline and 185 miles under construction.

Transwestern is a major natural gas transporter to the California border and delivers natural gas from the east end of its system to Texas intrastate and Midwest markets. The Transwestern pipeline interconnects with our existing intrastate pipelines in West Texas. The revenues of our interstate transportation operations consist primarily of fees earned from natural gas transportation services and operational gas sales.

Revenue in our midstream operations is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines (excluding the interstate transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

Our retail propane operations sell propane and propane-related products and services. The HOLP and Titan customer base includes residential, commercial, industrial and agricultural customers.

Recent Developments

MEP Transaction

On May 26, 2010, ETP completed the transfer of its membership interests in ETC Midcontinent Express Pipeline III, L.L.C. (“ETC MEP III”) to ETE (the “MEP Transaction”). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC (“MEP”), a joint venture with Kinder Morgan Energy Partners, L.P. (“KMP”) that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, ETP redeemed 12,273,830 ETP common units that were previously owned by ETE. ETP also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. This closing adjustment is subject to change during a final review period as defined in the contribution agreement. ETP also granted ETE an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. (“ETC MEP II”). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of its interest in ETC MEP III, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of its interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP (“Regency”) in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc. (“GE EFS”).

ETP continues to guarantee 50% of MEP’s obligations under MEP’s $175.4 million senior revolving credit facility, with the remaining 50% of MEP’s obligations guaranteed by KMP; however, Regency has agreed to indemnify ETP for any costs related to the guaranty of payments under this facility.

Other Acquisition

In January 2010, ETP purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, ETP recorded customer contracts of $68.2 million and goodwill of $27.3 million.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month's financial statements. Management believes that the operating results estimated for the year ended December 31, 2009 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition

Revenues for sales of natural gas, NGLs including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

ETP's intrastate transportation and storage and interstate transportation operations' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

ETP's intrastate transportation and storage operations also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from midstream's marketing operations, and from producers at the wellhead.

In addition, ETP's intrastate transportation and storage operations generate revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from ETP's midstream operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in ETP's midstream operations, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

ETP conducts marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

ETP has a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

Regulatory Accounting - Regulatory Assets and Liabilities

Transwestern, part of our interstate transportation operations, is subject to regulation by certain state and federal authorities and has accounting policies that conform to Statement of Financial Accounting Standards No. 71 (As Amended), *Accounting for the Effects of Certain Types of Regulation*, now incorporated into ASC 980, which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management’s assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

As a result of our acquisition of a natural gas compression equipment business in exchange for ETP Common Units, cash acquired in connection with acquisitions during 2009 exceeded the cash we paid by $30.4 million.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Accounts receivable	$ 28,431	$ 220,635	$ (169,263)	$ 54,347
Accounts receivable from related companies	(28,944)	1,858	(12,521)	(5,908)
Inventories	(101,592)	96,145	(168,430)	196,173
Exchanges receivable	22,074	(7,888)	(4,216)	(3,406)
Other current assets	8,167	(57,052)	(4,702)	53,598
Intangibles and other assets	(4,786)	(40,752)	605	(1,817)
Accounts payable	(16,024)	(296,185)	195,644	(92,172)
Accounts payable to related companies	4,455	(24,751)	25,459	32,936
Exchanges payable	(35,433)	14,254	6,117	3,000
Accrued and other current liabilities	(123,363)	32,377	976	(27,461)
Interest payable	29,963	42,951	33,415	14,844
Other long-term liabilities	1,401	1,741	(680)	1,460
Price risk management liabilities, net	(108,193)	75,874	7,022	30,103
Net change in assets and liabilities, net of effect of acquisitions	$(323,844)	$ 59,207	$ (90,574)	$255,697

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NON-CASH INVESTING ACTIVITIES:				
Transfer of investment in affiliate in purchase of Transwestern (Note 3)	$ —	$ —	$ —	$956,348
Investment in Calpine Corporation received in exchange for accounts receivable	$ —	$ 10,816	$ —	$ —
Capital expenditures accrued	$ 46,134	$ 153,230	$ 87,622	$ 43,498
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 26,237	$ 5,077	$ 3,896	$533,625
Subsidiary issuance of common units in connection with certain acquisitions	$ 63,339	$ 2,228	$ 1,400	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$ 367,924	$ 237,620	$ 51,465	$184,993
Cash paid for income taxes	$ 15,447	$ 4,674	$ 9,009	$ 8,583

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reflected as current assets on the consolidated balance sheets at fair value.

During the year ended December 31, 2008, we determined there was an other-than-temporary decline in the market value of one of our available-for-sale securities, and reclassified into earnings a loss of $1.4 million, which is recorded in other expense. Unrealized holding gains (losses), net of tax, of $7.4 million, $(6.4) million, $(0.1) million, and $0.3 million were recorded through accumulated other comprehensive income ("AOCI"), based on the market value of the securities, for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively. The change in value of our available-for-sale securities for the year ended December 31, 2009 includes realized losses of $3.5 million reclassified from AOCI during the period as discussed in "Accounts Receivable" below.

Accounts Receivable

ETC OLP deals with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. Management believes that the occurrence of bad debt in our midstream and intrastate transportation and storage operations was not significant at December 31, 2009 or 2008; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage operations was not deemed necessary.

ETP's interstate transportation operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Transwestern's management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Transwestern establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. Transwestern considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

ETP propane operations grant credit to their customers for the purchase of propane and propane-related products. Included in accounts receivable are trade accounts receivable arising from HOLP's retail and wholesale propane and Titan's retail propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane operations are recorded as amounts are billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the propane operations is based on management's assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

ETP enters into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

ETP exchanged a portion of its outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation ("Calpine") common stock valued at $10.8 million during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock is included in marketable securities on the consolidated balance sheet at a fair value of $4.8 million as of December 31, 2008. In 2009, ETP sold the stock for $7.3 million and recorded a realized loss of $3.6 million, of which $3.5 million was reclassified from AOCI to other income in the consolidated statement of operations.

Accounts receivable consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas operations	$ 429,849	$ 444,816
Propane	143,011	155,191
Less - allowance for doubtful accounts	(6,338)	(8,750)
Total, net	$ 566,522	$ 591,257

The activity in the allowance for doubtful accounts consisted of the following:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Balance, beginning of period	$ 8,750	$ 5,698	$ 5,601	$ 4,000
Accounts receivable written off, net of recoveries	(5,404)	(4,963)	(447)	(2,628)
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Balance, end of period	$ 6,338	$ 8,750	$ 5,698	$ 5,601

Inventories

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 157,103	$ 184,727
Propane	66,686	63,967
Appliances, parts and fittings and other	166,165	23,654
Total inventories	$ 389,954	$ 272,348

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheet and have been recorded in cost of products sold in our consolidated statements of operations.

During 2009, we recorded lower of cost or market adjustments of $54.0 million, which were offset by fair value adjustments related to our application of fair value hedging, of $66.1 million.

During 2008, we recorded lower-of-cost-or-market adjustments of $69.5 million for natural gas inventory and $4.4 million for propane inventory to reflect market values, which were less than the weighted-average cost. The natural gas inventory adjustment in 2008 was partially offset in net income by the recognition of unrealized gains on related cash flow hedges in the amount of $21.7 million from AOCI.

Exchanges

ETP's midstream and intrastate transportation and storage operations' exchanges consist of natural gas and NGL delivery imbalances with others. These amounts, which are valued at market prices, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheet. Management believes market value approximates cost.

ETP's interstate transportation operations' natural gas imbalances occur as a result of differences in volumes of gas received and delivered. Transwestern records natural gas imbalances for in-kind receivables and payables at the dollar weighted composite average of all current month gas transactions and dollar valued imbalances are recorded at contractual prices.

Other Current Assets

Other current assets consisted of the following:

	December 31, 2009	December 31, 2008
Deposits paid to vendors	$ 79,694	$ 78,237
Prepaid and other	68,729	75,276
Total other current assets	$ 148,423	$ 153,513

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or Federal Energy Regulatory Commission ("FERC") mandated lives of the assets. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the installation of company-owned propane tanks and construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our results of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of long-lived assets was required during the periods presented.

Capitalized interest is included for pipeline construction projects, except for interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of ETP's revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2009	December 31, 2008
Land and improvements	$ 87,224	$ 74,731
Buildings and improvements (10 to 40 years)	156,676	129,714
Pipelines and equipment (10 to 83 years)	6,933,189	5,136,357
Natural gas storage (40 years)	100,746	92,457
Bulk storage, equipment and facilities (3 to 83 years)	591,908	533,621
Tanks and other equipment (10 to 30 years)	602,915	578,118
Vehicles (3 to 10 years)	176,946	156,486
Right of way (20 to 83 years)	509,173	358,669
Furniture and fixtures (3 to 10 years)	32,810	28,075
Linepack	53,404	48,108
Pad gas	47,363	53,583
Other (5 to 10 years)	117,896	97,975
	9,410,250	7,287,894
Less – Accumulated depreciation	(979,158)	(700,826)
	8,431,092	6,587,068
Plus – Construction work-in-process	239,155	1,709,017
Property, plant and equipment, net	$8,670,247	$8,296,085

We recognized the following amounts of depreciation expense, capitalized interest, and AFUDC for the periods presented:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Depreciation expense	$ 291,908	$ 244,689	$ 64,569	$163,630
Capitalized interest, excluding AFUDC	$ 11,791	$ 21,595	$ 12,657	$ 22,979
AFUDC (both debt and equity components)	$ 10,237	$ 50,074	$ 5,095	$ 3,600

Advances to and Investment in Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we have a 20% to 50% ownership and exercise significant influence over, but do not control the investee’s operating and financial policies.

We account for our investments in Midcontinent Express Pipeline LLC and Fayetteville Express Pipeline LLC using the equity method. See Note 4 for a discussion of these joint ventures.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of December 31 for subsidiaries in our interstate operations and as of August 31 for all others. At December 31, 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No other goodwill impairments were recorded for the periods presented in these consolidated financial statements. Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation	Midstream	Retail Propane	All Other	Total
Balance, December 31, 2007	$ 10,327	$ 98,613	$ 24,368	$594,801	$29,588	$757,697
Purchase accounting adjustments	—	—	—	2,457	—	2,457
Goodwill acquired	—	—	9,141	15,346	—	24,487
Goodwill Impairment	—	—	(11,359)	—	—	(11,359)
Balance, December 31, 2008	10,327	98,613	22,150	612,604	29,588	773,282
Purchase accounting adjustments	—	—	—	(8,662)	—	(8,662)
Goodwill acquired	—	—	—	33	10,440	10,473
Balance December 31, 2009	$ 10,327	$ 98,613	$ 22,150	$603,975	$40,028	$775,093

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

Intangibles and Other Assets

Intangibles and other assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other assets were as follows:

	December 31, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (3 to 15 years)	$ 24,139	$ (12,415)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,843	(53,123)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(5,638)	23,015	(3,744)
Patents (9 years)	750	(35)	—	—
Other (10 years)	478	(397)	2,677	(2,244)
Total amortizable intangible assets	202,225	(71,608)	210,330	(70,092)
Non-amortizable intangible assets - Trademarks	75,825	—	75,667	—
Total intangible assets	278,050	(71,608)	285,997	(70,092)
Other assets:				
Financing costs (3 to 30 years)	68,597	(24,774)	59,108	(16,586)
Regulatory assets	101,879	(9,501)	98,560	(5,941)
Other	41,466	—	43,353	—
Total intangibles and other assets	$ 489,992	$ (105,883)	$ 487,018	$ (92,619)

Aggregate amortization expense of intangible and other assets are as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Reported in depreciation and amortization	$ 20,895	$ 17,462	$ 6,764	$ 15,532
Reported in interest expense	$ 8,188	$ 6,008	$ 1,710	$ 4,502

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2010	$26,991
2011	25,326
2012	21,740
2013	16,310
2014	15,343

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate operations and as of August 31 for all others. No impairment of intangible assets was required during the periods presented in these consolidated financial statements.

Asset Retirement Obligation

We record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, we also recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

We have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates. However, management was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2009 or 2008 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2009	December 31, 2008
Customer advances and deposits	$ 88,430	$ 106,679
Accrued capital expenditures	46,134	153,230
Accrued wages and benefits	25,202	64,692
Taxes other than income taxes	23,294	20,772
Income taxes payable	3,401	14,538
Deferred income taxes	—	589
Other	42,485	73,294
Total accrued and other current liabilities	$ 228,946	$ 433,794

Customer Advances and Deposits

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Fair Value of Financial Instruments

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at December 31, 2009 was $6.75 billion and $6.22 billion, respectively. At December 31, 2008, the aggregate fair value and carrying amount of long-term debt was $5.10 billion and $5.66 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (“OTC”) commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. We currently do not have any fair value measurements that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations.

The following table summarizes the fair value of our financial assets and liabilities as of December 31, 2009 and 2008 based on inputs used to derive their fair values:

	Fair Value Measurements at December 31, 2009 Using			Fair Value Measurements at December 31, 2008 Using		
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets:						
Marketable securities	$ 6,055	$ 6,055	$ —	$ 5,915	$ 5,915	$ —
Natural gas inventories	156,156	156,156	—	—	—	—
Commodity derivatives	32,479	20,090	12,389	111,513	106,090	5,423
Liabilities:						
Commodity derivatives	(8,016)	(7,574)	(442)	(43,336)	—	(43,336)
Interest rate swap derivatives	—	—	—	(51,642)	—	(51,642)
	$186,674	$ 174,727	$ 11,947	$ 22,450	$ 112,005	$ (89,555)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs ("CIAC") are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized. In March 2008, we received a reimbursement related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million, which is recorded in other income on our consolidated statement of operations for the year ended December 31, 2008.

Contributions in aid of construction costs were as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Received and netted against project costs	$ 6,453	$ 50,050	$ 3,493	$ 10,463
Recorded in other income	(305)	8,352	216	403
Totals	$ 6,148	$ 58,402	$ 3,709	$ 10,866

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and totaled $55.9 million and $112.0 million for the years ended December 31, 2009 and 2008, respectively, $30.7 million for the four months ended December 31, 2007 and $58.6 million for the year ended August 31, 2007. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs and plant operations. Selling, general and administrative expenses include all partnership related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis.

Income Taxes

ETP GP is a limited partnership. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual partners. Net earnings for financial statement purposes may differ significantly from taxable income reportable to Unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

ETP will be considered to have terminated for federal income tax purposes if the transfer of ETP units within a 12-month period constitute the sale or exchange of 50% or more of our capital and profits interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of ETP's capital and profits interests within the prior 12-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

ETP exceeded the 50% threshold on May 7, 2007, and, as a result, ETP terminated for federal tax income purposes on that date. This termination did not affect ETP's classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of ETP's "qualifying income" for federal income tax purposes. This termination required ETP to close its taxable year, make new elections as to various tax matters and reset the depreciation schedule for its depreciable assets for federal income tax purposes. The resetting of its depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to ETP's Unitholders. However, certain elections made by ETP in connection with this tax termination allowed us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of ETP's Unitholders, which deductions had not previously been utilized in computing taxable income allocable to ETP's Unitholders.

As a result of the tax termination discussed above, ETP elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our subsidiary, Heritage Holdings, Inc. ("HHI"), which owns ETP's Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of ETP Common Units. The amount of such "goodwill" accumulated as of the date of ETP's acquisition of HHI (approximately $158.0 million) is now being amortized over 15 years beginning on May 7, 2007, the date of ETP's new tax elections. We account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of ETP's HHI purchase price allocation, which effectively results in a charge to our noncontrolling interest and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the years ended December 31, 2009 and 2008, the four months ended December, 31, 2007, and the year ended August 31, 2007, this resulted in a current tax expense and deferred tax benefit (with a corresponding charge to common equity as an adjustment of the purchase price allocation) of approximately $3.8 million, $3.4 million, $1.2 million and $1.2 million, respectively. As of December 31, 2009, the amount of tax goodwill to be amortized over the next 13 years for which HHI will receive a remedial income allocation is approximately $132.8 million.

We are treated as a disregarded entity for federal income tax purposes; therefore, certain income tax elections that ETE may make in the future could impact the amount of income tax expense that we recognize in future periods.

As a limited partnership, ETP is generally not subject to income tax. ETP is, however, subject to a statutory requirement that its non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of its total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of ETP's non-qualifying income exceeds this statutory limit, ETP would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries ("C corporations") of ETP. These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, ETP's non-qualifying income did not exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes, under which deferred income taxes are recorded based upon differences between the financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

Accounting for Derivative Instruments and Hedging Activities

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our operations as follows:

- Derivatives are utilized in ETP's midstream operations in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- ETP uses derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. ETP also uses derivatives in our intrastate transportation and storage operations to hedge the sales price of retention gas and hedge location price differentials related to the transportation of natural gas.
- ETP's propane operations permit customers to guarantee the propane delivery price for the next heating season. As ETP executes fixed sales price contracts with our customers, ETP may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, ETP may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge's change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We are exposed to market risk for changes in interest rates related to our revolving credit facilities. We previously have managed a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not accounted for as cash flow hedges are classified in other income. See Note 11 for additional information related to interest rate derivatives

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 6). Normal allocations according to percentage interests are made after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner.

Unit-Based Compensation

ETP accounts for equity awards issued to employees over the vesting period based on the grant-date fair value. The grant-date fair value is determined based on the market price of ETP's Common Units on the grant date, adjusted to reflect the present value of any expected distributions that will not accrue to the employee during the vesting period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected distributions based on the most recently declared distributions as of the grant date.

New Accounting Standards

Accounting Standards Codification. On July 1, 2009, the Financial Accounting Standards Board ("FASB") instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The *FASB Accounting Standards Codification*™ ("ASC") is now the single authoritative source for GAAP. Although the implementation of ASC has no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Noncontrolling Interests. On January 1, 2009, we adopted SFAS 160, now incorporated into ASC 810-10, which established new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, the new standard requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent's equity. The amount of net income attributable to the noncontrolling interest is included in consolidated net income on the face of the income statement. The new standard clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, the new standard requires that a parent recognizes a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss is measured using the fair value of the noncontrolling equity investment on the deconsolidation date. This standard also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. The adoption of this standard did not have a significant impact on our financial position or results of operations. However, it did result in certain changes to our financial statement presentation, including the change in classification of noncontrolling interest (minority interest) from liabilities to equity on the condensed consolidated balance sheet.

Upon adoption, we reclassified $3.58 billion from minority interest liability to noncontrolling interest as a separate component of equity on our consolidated balance sheet as of December 31, 2008. In addition, we reclassified $550.1 million, $170.8 million and $441.4 million of minority interest expense to net income attributable to noncontrolling interest in our consolidated statements of operations for the year ended December 31, 2008, the four month transition period ended December 31, 2007 and the year ended August 31, 2007.

Business Combinations. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations*, which is now incorporated into ASC 805. The new standard significantly changes the accounting for business combinations and includes a substantial number of new disclosure requirements. The new standard requires an acquiring entity to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions and changes the accounting treatment for certain specific items, including:

- Acquisition costs are generally expensed as incurred;
- Noncontrolling interests (previously referred to as “minority interests”) are valued at fair value at the acquisition date;
- In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;
- Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

Our adoption of this standard did not have an immediate impact on our financial position or results of operations; however, it has impacted the accounting for our business combinations subsequent to adoption.

Derivative Instruments and Hedging Activities. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133*, which is now incorporated into ASC 815. This standard changed the disclosure requirements for derivative instruments and hedging activities, including requirements for qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The standard only affected disclosure requirements; therefore, our adoption did not impact our financial position or results of operations.

Equity Method Investment Accounting. On January 1, 2009, we adopted Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations*, which is now incorporated into ASC 323-10. This standard establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment, and also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. Our adoption did not have a material impact on our financial position or results of operations.

Subsequent Events. During 2009, we adopted Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events*, which is now incorporated into ASC 855. Under this standard, we are required to evaluate subsequent events through the date that our financial statements are issued and also required to disclose the date through which subsequent events are evaluated. The adoption of this standard does not change our current practices with respect to evaluating, recording and disclosing subsequent events; therefore, our adoption of this statement during the second quarter had no impact on our financial position or results of operations.

3. ACQUISITIONS:

2010

In January 2010, ETP purchased a natural gas gathering company which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale. The purchase price is $150 million in cash, excluding certain adjustments as defined in the purchase agreement, and the acquisition closed in March 2010.

2009

In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas, in exchange for our issuance of 1,450,076 Common Units having an aggregate market value of approximately $63.3 million on the closing date. In connection with this transaction, we received cash of $41.1 million, assumed total liabilities of $30.5 million, which includes $8.4 million in notes payable and recorded goodwill of $8.7 million. In addition, we acquired ETG in August 2009. See Note 13.

2008

During the year ended December 31, 2008, HOLP and Titan collectively acquired substantially all of the assets of 20 propane businesses. The aggregate purchase price for these acquisitions totaled $96.4 million, which included $76.2 million of cash paid, net of cash acquired, liabilities assumed of $8.2 million, 53,893 Common Units issued valued at $2.2 million and debt forgiveness of $9.8 million. The cash paid for acquisitions was financed primarily with ETP's and HOLP's Senior Revolving Credit Facilities. We recorded $15.3 million of goodwill in connection with these acquisitions.

Transition Period 2007

Canyon Acquisition

In October 2007, we acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the “Canyon acquisition”) for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The purchase price was initially allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. We completed the purchase price allocation during the third quarter of 2008. The adjustments to the purchase price allocation were not material. The final allocations of the purchase price are noted below:

Accounts receivable	$ 3,613
Inventory	183
Prepaid and other current assets	1,606
Property, plant, and equipment	284,910
Intangibles and other assets	6,351
Goodwill	11,359
Total assets acquired	308,022
Accounts payable	(1,840)
Customer advances and deposits	(1,030)
Total liabilities assumed	(2,870)
Net assets acquired	$305,152

2007

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (“GE”) and Southern Union Company (“Southern Union”), we acquired the member interests in CCE Holdings, LLC (“CCEH”) from GE and certain other investors for $1.00 billion. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to ETE simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP’s 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern, which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and formed our interstate transportation operations.

The total acquisition cost for Transwestern, net of cash acquired, was as follows:

Basis of investment in CCEH at November 30, 2006	$ 956,348
Distributions received on December 1, 2006	(6,217)
Fair value of short-term debt assumed	13,000
Fair value of long-term debt assumed	519,377
Other assumed long-term indebtedness	10,096
Current liabilities assumed	35,781
Cash acquired	(3,386)
Acquisition costs incurred	11,696
Total	$1,536,695

In September 2006, we acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of $30.6 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas and are included in our midstream operations. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility. In March 2008, a contingent payment of $8.7 million was recorded as an adjustment to goodwill in our midstream operations.

In December 2006, we purchased a natural gas gathering system in north Texas for $32.0 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $21.0 million to be determined two years after the closing date. In December 2008, it was determined that a contingency payment would not be required. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility.

During the fiscal year ended August 31, 2007, HOLP and Titan collectively acquired substantially all of the assets of five propane businesses. The aggregate purchase price for these acquisitions totaled $17.6 million, which included $15.5 million of cash paid, net of cash acquired, and liabilities assumed of $2.1 million. The cash paid for acquisitions was financed primarily with ETP's and HOLP's Senior Revolving Credit Facilities.

Except for the acquisition of the 50% member interests in CCEH, our acquisitions were accounted for under the purchase method of accounting and the purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. The acquisition of 100% of Transwestern has been accounted for under the purchase method of accounting since the acquisition on December 1, 2006.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for the fiscal year 2007 acquisitions described above, net of cash acquired:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$ —	$ 20,062	$ 1,111
Inventory	—	895	414
Prepaid and other current assets	—	11,842	57
Investment in unconsolidated affiliate	(503)	—	—
Property, plant, and equipment	50,916	1,254,968	8,035
Intangibles and other assets	23,015	141,378	3,808
Goodwill	—	107,550	4,167
Total assets acquired	73,428	1,536,695	17,592
Accounts payable	—	(1,932)	(381)
Customer advances and deposits	—	(700)	(254)
Accrued and other current liabilities	(292)	(33,149)	(170)
Short-term debt (paid in December 2006)	—	(13,000)	—
Long-term debt	—	(519,377)	(1,309)
Other long-term obligations	—	(10,096)	—
Total liabilities assumed	(292)	(578,254)	(2,114)
Net assets acquired	$ 73,136	$ 958,441	$ 15,478

The purchase price for the acquisitions was initially allocated based on the estimated fair value of the assets acquired and liabilities assumed. The Transwestern allocation was based on the preliminary results of independent appraisals. The purchase price allocations were completed during the first quarter of 2008. The final allocation adjustments were not significant.

Included in the property, plant and equipment associated with the Transwestern acquisition is an aggregate plant acquisition adjustment of $446.2 million, which represents costs allocated to Transwestern's transmission plant. This amount has not been included in the determination of tariff rates Transwestern charges to its regulated customers. The unamortized balance of this adjustment was $419.6 million at December 31, 2008 and is being amortized over 35 years, the composite weighted average estimated remaining life of Transwestern's assets as of the acquisition date.

Regulatory assets, included in intangible and other assets on the consolidated balance sheet, established in the Transwestern purchase price allocation consist of the following:

Accumulated reserve adjustment	$42,132
AFUDC gross-up	9,280
Environmental reserves	6,623
South Georgia deferred tax receivable	2,593
Other	9,329
Total Regulatory Assets acquired	$69,957

All of Transwestern's regulatory assets are considered probable of recovery in rates.

We recorded the following intangible assets and goodwill in conjunction with the fiscal year 2007 acquisitions described above:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Intangible assets:			
Contract rights and customer lists (6 to 15 years)	$ 23,015	$ 47,582	$ —
Financing costs (7 to 9 years)	—	13,410	—
Other	—	—	3,808
Total intangible assets	23,015	60,992	3,808
Goodwill	—	107,550	4,167
Total intangible assets and goodwill acquired	$ 23,015	$ 168,542	$ 7,975

Goodwill was warranted because these acquisitions enhance our current operations, and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible. We do not believe that the acquired intangible assets have any significant residual value at the end of their useful life.

4. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

ETP is party to an agreement with Kinder Morgan Energy Partners, L.P. ("KMP") for a 50/50 joint development of the Midcontinent Express pipeline. Construction of the approximately 500-mile pipeline was completed and natural gas transportation service commenced August 1, 2009 on the pipeline from Delhi, Louisiana, to an interconnect with the Transco interstate natural gas pipeline in Butler, Alabama. Interim service began on the pipeline from Bennington, Oklahoma, to Delhi in April 2009. In July 2008, Midcontinent Express Pipeline LLC ("MEP"), the entity formed to construct, own and operate this pipeline, completed an open season with respect to a capacity expansion of the pipeline from the current capacity of 1.4 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to an interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is expected to be completed in the latter part of 2010. This expansion was approved by the Federal Energy Regulatory Commission (the "FERC") in September 2009.

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

On May 26, 2010, ETP transferred to ETE, in exchange for ETP common units owned by ETE, substantially all of its interest in MEP. In conjunction with this transfer, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of the interest to its estimated fair value. See discussion of the transaction in "Recent Developments" at Note 1.

Fayetteville Express Pipeline LLC

ETP is party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC (“FEP”), the entity formed to construct, own and operate this pipeline, received FERC approval of its application for authority to construct and operate this pipeline. That order is currently subject to a limited request for rehearing. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. The pipeline project is expected to be in service by the end of 2010. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America (“NGPL”) in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

Capital Contributions to Affiliates

During the year ended December 31, 2009, we contributed $664.5 million to MEP. FEP’s capital expenditures are being funded under a credit facility. All of our contributions to FEP were reimbursed to us in 2009, including $9.0 million that we contributed in 2008.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, MEP and FEP (on a 100% basis):

	December 31, 2009	December 31, 2008
Current assets	$ 33,794	$ 9,953
Property, plant and equipment, net	2,576,031	1,012,006
Other assets	19,658	—
Total assets	$2,629,483	$1,021,959
Current liabilities	$ 105,951	$ 163,379
Non-current liabilities	1,198,882	840,580
Equity	1,324,650	18,000
Total liabilities and equity	$2,629,483	$1,021,959

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Revenue	$ 98,593	$ —	$ —	$ —
Operating income	47,818	—	—	—
Net income	36,555	1,057	—	—

As stated above, MEP was placed into service during 2009.

5. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

	December 31, 2009	December 31, 2008	
ETP Senior Notes:			
5.95% Senior Notes, due February 1, 2015	$ 750,000	$ 750,000	Payable upon maturity. Interest is paid semi-annually.
5.65% Senior Notes, due August 1, 2012	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.125% Senior Notes, due February 15, 2017	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.625% Senior Notes, due October 15, 2036	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.0% Senior Notes, due July 1, 2013	350,000	350,000	Payable upon maturity. Interest is paid semi-annually.
6.7% Senior Notes, due July 1, 2018	600,000	600,000	Payable upon maturity. Interest is paid semi-annually.
7.5% Senior Notes, due July 1, 2038	550,000	550,000	Payable upon maturity. Interest is paid semi-annually.
9.7% Senior Notes due March 15, 2019	600,000	600,000	Put option on March 15, 2012. Payable upon maturity. Interest is paid semi-annually.
8.5% Senior Notes due April 15, 2014	350,000	—	Payable upon maturity. Interest is paid semi-annually.
9.0% Senior Notes due April 15, 2019	650,000	—	Payable upon maturity. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Notes, due November 17, 2014	88,000	88,000	Payable upon maturity. Interest is paid semi-annually.
5.54% Senior Unsecured Notes, due November 17, 2016	125,000	125,000	Payable upon maturity. Interest is paid semi-annually.
5.64% Senior Unsecured Notes, due May 24, 2017	82,000	82,000	Payable upon maturity. Interest is paid semi-annually.
5.89% Senior Unsecured Notes, due May 24, 2022	150,000	150,000	Payable upon maturity. Interest is paid semi-annually.
6.16% Senior Unsecured Notes, due May 24, 2037	75,000	75,000	Payable upon maturity. Interest is paid semi-annually.
5.36% Senior Unsecured Notes, due December 9, 2020	175,000	—	Payable upon maturity. Interest is paid semi-annually.
5.66% Senior Unsecured Notes, due December 9, 2024	175,000	—	Payable upon maturity. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	24,000	36,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
Medium Term Note Program:			
7.17% Series A Senior Secured Notes	—	2,400	Matured in November 2009.
7.26% Series B Senior Secured Notes	6,000	8,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	4,571	9,142	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	5,750	11,500	Annual payments of $5,750 due August 15, 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	33,100	45,550	Annual payments of $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	6,000	7,000	Annual payments of $1,000 due each August 15 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.89% Series H Senior Secured Notes	5,091	5,818	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility	150,000	902,000	See terms below under "ETP Credit Facility".
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	10,000	See terms below under "HOLP Credit Facility".
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 8.06% and 7.91% for December 31, 2009 and 2008, respectively	7,898	11,249	Due in installments through 2014.
Other	2,388	2,765	Due in installments through 2024.
Unamortized discounts	(12,829)	(13,477)	
	6,217,969	5,663,947	
Current maturities	(40,923)	(45,232)	
	$6,177,046	$5,618,715	

Future maturities of long-term debt for each of the next five years and thereafter are as follows:

2010	$ 40,923
2011	44,607
2012	572,881
2013	372,569
2014	443,519
Thereafter	4,743,470
	$6,217,969

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). ETP may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

In April 2009, ETP completed a public offering of $350.0 million aggregate principal amount of 8.5% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.0% Senior Notes due 2019 (collectively the "2009 ETP Notes"). The offering of the 2009 ETP Notes closed on April 7, 2009 and ETP used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

Transwestern Senior Unsecured Notes

Transwestern's long-term debt consists of $213.0 million remaining principal amount of notes assumed in connection with the Transwestern acquisition, $307.0 million aggregate principal amount of notes issued in May 2007, and $350.0 million aggregate principal amount of notes issued in December 2009. The proceeds from the notes issued in December 2009 were used by Transwestern to repay amounts under an intercompany loan agreement. No principal payments are required under any of the Transwestern notes prior to their respective maturity dates. The Transwestern notes rank pari passu with Transwestern's other unsecured debt. The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. Interest is paid semi-annually.

Transwestern's debt agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the "HOLP Notes").

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity, under the Amended and Restated Credit Agreement). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of December 31, 2009, there was a balance outstanding in the ETP Credit Facility of $150.0 million in revolving credit loans and approximately $62.2 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2009 was 0.78%. The total amount available under the ETP Credit Facility, as of December 31, 2009, which is reduced by any letters of credit, was approximately $1.79 billion. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of ETP's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility (total book value as of December 31, 2009 of approximately $1.2 billion). At December 31, 2009, there was $10.0 million outstanding in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of December 31, 2009 was $64.0 million.

Covenants Related to Our Credit Agreements

The agreements related to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions. The agreements and indentures related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to ETP and the Operating Companies, including the maintenance of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens as described in further detail below.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) ETP's and certain of ETP's subsidiaries, ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by ETP and its subsidiaries;
- engage in transactions with affiliates;
- enter into restrictive agreements; and
- enter into speculative hedging contracts.

The credit agreement related to the ETP Credit Facility also contains a financial covenant that provides that on each date we make a distribution, the leverage ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1, with a permitted increase to 5.5 to 1 during a specified acquisition period, as defined in the ETP Credit Facility. This financial covenant could therefore restrict our ability to make cash distributions to our Unitholders, our general partner and the holder of our incentive distribution rights.

The agreements related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to HOLP, including the maintenance of various financial and leverage covenants and limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The financial covenants require HOLP to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not less than 2.25 to 1. These debt agreements also provide that HOLP may declare, make, or incur a liability to make restricted payments during each fiscal quarter, if: (a) the amount of such restricted payment, together with all other restricted payments during such quarter, do not exceed the amount of Available Cash (as defined in the agreements related to the HOLP Notes and HOLP Credit Facility) with respect to the immediately preceding quarter (which amount is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes during the last quarter and in addition, in the third, second and first quarters preceding a quarter in which a scheduled principal payment is to be made on the HOLP Notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates), (b) no default or event of default exists before such restricted payments, and (c) the amounts of HOLP's restricted payment is not disproportionately greater than the payment amount from ETC OLP utilized to fund payment obligations of ETP and its general partner with respect to ETP's Common Units.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities and the note agreements related to the HOLP Notes could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

We are required to assess compliance quarterly and we were in compliance with all requirements, limitations, and covenants related to our debt agreements as of December 31, 2009.

6. PARTNERS' CAPITAL:

In January 2006, we amended our Partnership Agreement to re-characterize our limited partner interest into Class A Limited Partner interests and Class B Limited Partner interests. The Class B Limited Partnership interests constitute a profits interest in ETP GP and will only receive allocations of income, gain, loss deduction and credit and their pro rata share of cash distributions from ETP GP attributable to the ownership of ETP's Incentive Distribution Rights ("IDR"). Under our Partnership Agreement, after giving effect to the special allocation of net income to our Class B Limited Partners for their profits interest, net income is allocated among the Partners as follows:

- First, 100% to our General Partner, until the aggregate net income allocated to our General Partner for the current year and all previous years is equal to the aggregate net losses allocated to our General Partner for all previous years;
- Second, 99.99% to our Class A Limited Partners, in proportion to their relative allocation of net losses, and .01% to our General Partner until the aggregate net income allocated to our Class A Limited Partners and our General Partner for the current and all previous years is equal to the aggregate net losses allocated to our Class A Limited Partners and our General Partner for all previous years; and
- Third, 99% to our Class A Limited Partners, pro rata, and .01% to our General Partner.

Sale of Common Units by ETP

In January 2010, ETP issued 9,775,000 ETP Common Units through a public offering. The proceeds of $423.6 million from the offering were used primarily to repay borrowings under ETP's revolving credit facility and to fund capital expenditures related to pipeline projects.

On August 26, 2009, ETP entered into an Equity Distribution Agreement with UBS Securities LLC ("UBS"). Pursuant to this agreement, ETP may offer and sell from time to time through UBS, as their sales agent, ETP Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between ETP and UBS. Under the terms of this agreement, ETP may also sell ETP Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of ETP Common Units to UBS as principal would be pursuant to the terms of a separate agreement between ETP and UBS. During the six months ended June 30, 2010, ETP issued 3,340,783 ETP Common Units pursuant to this agreement. The proceeds of approximately $151.0 million, net of commissions, were used for general partnership purposes. In addition, ETP initiated trades on an additional 501,500 ETP Common Units that had not settled as of June 30, 2010. Approximately $40.6 million of ETP's Common Units remain available to be issued under the agreement based on trades initiated through June 30, 2010.

Quarterly Distributions of Available Cash

Our distributions policy is consistent with the terms of the Partnership Agreement, which requires that we distribute all of our available cash quarterly. Our only cash-generating assets consist of partnership interests, including IDRs, from which we receive quarterly distributions from ETP. We have no independent operations outside of our interests in ETP. Under the Partnership Agreement, our distributions are characterized as the GP Distribution Amount and the IDR Distribution Amount. The GP Distribution Amount is all distributions we receive from ETP with respect to our General Partner Interest and the IDR Distribution Amount is all distributions received from ETP with respect to the IDR. Within 45 days following the end of each quarter, we will distribute all of our GP Available Cash and IDR Available Cash, as defined in the Partnership Agreement. GP Available Cash shall be distributed 99.99% to the Class A Limited Partners, pro rata and 0.01% to the General partner. IDR Available Cash shall be distributed 99.99% to the Class B Limited Partners, pro rata and 0.01% to the General Partner.

ETP GP has the right, in connection with the issuance of any equity security by ETP, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in ETP as ETP GP and its affiliates owned immediately prior to such issuance.

Contributions to Subsidiary

In order to maintain our general partner interest in ETP, ETP GP has previously been required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP. ETP GP was required to contribute approximately $12.3 million and $8.0 million for the years ended December 31, 2009 and 2008, $5.0 million for the four months ended December 31, 2007 and $24.5 million for the year ended August 31, 2007, respectively. As of December 31, 2009, ETP GP has a contribution payable to ETP of $8.9 million.

In July 2009, ETP amended and restated its partnership agreement, and as a result, ETP GP is no longer required to make corresponding contributions to maintain its general partner interest in ETP.

ETP's Quarterly Distribution of Available Cash

ETP's Partnership Agreement requires that ETP distribute all of its Available Cash to its Unitholders and its General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any fiscal quarter of ETP, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by its General Partner in its sole discretion to provide for the proper conduct of ETP's business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in ETP's Partnership Agreement.

ETP's distributions declared during the periods presented below are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2009	November 9, 2009	November 16, 2009	$ 0.89375
	August 7, 2009	August 14, 2009	0.89375
	May 8, 2009	May 15, 2009	0.89375
	February 6, 2009	February 13, 2009	0.89375
Calendar Year Ended December 31, 2008	November 10, 2008	November 14, 2008	$ 0.89375
	August 7, 2008	August 14, 2008	0.89375
	May 5, 2008	May 15, 2008	0.86875
	February 1, 2008 (1)	February 14, 2008	1.12500
Transition Period Ended December 31, 2007	October 5, 2007	October 15, 2007	$ 0.82500
Fiscal Year Ended August 31, 2007	July 2, 2007	July 16, 2007	$ 0.80625
	April 6, 2007	April 13, 2007	0.78750
	January 4, 2007	January 15, 2007	0.76875
	October 5, 2006	October 16, 2006	0.75000

(1) One-time four month distribution – On January 18, 2008 ETP's Board of Directors approved the management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP's distribution amount related to the four months ended December 31, 2007 was $1.125 per Common Unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This distribution was paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

The total amount of distributions ETP GP received from ETP relating to its general partner interests and incentive distribution rights of ETP are as follows (shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
General Partner interest	$ 19,505	$ 17,322	$ 5,110	$ 13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$ 369,991	$ 315,897	$ 90,885	$236,058

The total amounts of ETP distributions declared during the periods presented in the consolidated financial statements are as follows (all from Available Cash from ETP's operating surplus and are shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 629,263	$ 537,731	$ 160,672	$396,095
Class E Units	12,484	12,484	3,121	12,484
Class G Units	—	—	—	40,598
General Partner interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$1,011,738	$ 866,112	$ 254,678	$685,235

Upon their conversion to ETP Common Units, all the ETP Class G Units ceased to have the right to participate in ETP distributions of available cash from operating surplus as itemized above.

Distributions paid by ETP subsequent to December 31, 2009 are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2009	February 8, 2010	February 15, 2010	$0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at the close of business on August 9, 2010.

Accumulated Other Comprehensive Income

The following table presents the components of AOCI, net of tax:

	December 31, 2009	December 31, 2008
Net gain on commodity related hedges	$ 1,991	$ 8,735
Net gain on interest rate hedges	(125)	161
Unrealized gains (losses) on available-for-sale securities	4,941	(5,983)
Noncontrolling interest	(6,678)	(2,855)
Total AOCI, net of tax	$ 129	$ 58

7. UNIT-BASED COMPENSATION PLANS OF ETP:

ETP has issued equity awards to employees and directors under the following plans:

- ***2008 Long-Term Incentive Plan***. On December 16, 2008, ETP Unitholders approved the ETP 2008 Long-Term Incentive Plan (the “2008 Incentive Plan”), which provides for awards of options to purchase ETP Common Units, awards of restricted units, awards of phantom units, awards of Common Units, awards of distribution equivalent rights (“DERs”), awards of Common Unit appreciation rights, and other unit-based awards to employees of ETP, ETP GP, ETP LLC, a subsidiary or their affiliates, and members of ETP LLC’s board of directors, which we refer to as our board of directors. Up to 5,000,000 ETP Common Units may be granted as awards under the 2008 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2008 Incentive Plan. The 2008 Incentive Plan is effective until December 16, 2018 or, if earlier, the time which all available units under the 2008 Incentive Plan have been issued to participants or the time of termination of the plan by our board of directors. As of December 31, 2009, a total of 4,213,111 ETP Common Units remain available to be awarded under the 2008 Incentive Plan.
- ***2004 Unit Plan***. ETP’s Amended and Restated 2004 Unit Award Plan (the “2004 Unit Plan”) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers and directors. Any awards that are forfeited, or which expire for any reason or any units, which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. As of December 31, 2009, 5,578 ETP Common Units were available for future grants under the 2004 Unit Plan.

ETP Employee Grants

Prior to December 2007, substantially all of the awards granted to employees required the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three-year period with 100% of such one-third vesting if the total return for the ETP units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the

Compensation Committee, 65% of such one-third vesting if the total return of the ETP units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of the ETP units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of the ETP units for the year plus the aggregate per unit cash distributions received for the year. Non-cash compensation expense is recorded for these ETP awards based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded.

In October 2008, the Compensation Committee determined that, of the unit awards subject to the achievement of performance objectives, 25% of the ETP Common Units subject to such awards eligible to vest on September 1, 2007 became vested and 75% of the awards were forfeited based on ETP's performance for the twelve-month period ended August 31, 2008. In October 2008, the Compensation Committee approved a special grant of the new unit awards that entitled each holder to receive a number of ETP Common Units equal to the number of ETP Common Units forfeited as of September 1, 2007, which new unit awards became fully vested on October 15, 2008. These Compensation Committee actions affected all ETP employee unit awards including unit awards granted to ETP's executive officers.

Commencing in December 2007, ETP has also granted restricted unit awards to employees that vest over a specified time period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. Upon vesting, ETP Common Units are issued. The unit awards under ETP's equity incentive plans generally require the continued employment of the recipient during the vesting period; however, the Compensation Committee has complete discretion to accelerate the vesting of unvested unit awards.

In 2008 and 2009, the Compensation Committee approved the grant of new unit awards, which vest over a five-year period at 20% per year, subject to continued employment through each specified vesting date. These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. We refer to these rights as "distribution equivalent rights."

Prior to 2008 and 2009, units were generally awarded without distribution equivalent rights. For such awards, ETP calculated the grant-date fair value based on the market value of the underlying units, reduced by the present value of the distributions expected to be paid on the units during the requisite service period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the distribution yield at that time.

Director Grants

Under ETP's equity incentive plans, ETP's non-employee directors each receive unvested ETP Common Units with a grant-date fair value of $50,000 each year. These non-employee director grants vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

Award Activity

The following table shows the activity of the ETP awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2008	1,372,568	$ 36.83
Awards granted	763,190	43.56
Awards vested	(336,386)	36.02
Awards forfeited	(108,780)	39.17
Unvested awards as of December 31, 2009	1,690,592	39.88

The balance above for unvested awards as of December 31, 2008 includes 150,852 unit awards with a grant-date fair value of $43.96 per unit, which were granted prior to 2008 and were subject to a performance condition, as described above. These remaining performance awards vested in 2009, and none of the unvested unit awards outstanding as of December 31, 2009 contain performance conditions.

During the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, the weighted average grant-date fair value per unit award granted was $43.56, $33.86, $42.46 and $43.73, respectively. The total fair value of awards vested was $14.7 million, $14.6 million, $3.3 million and $7.9 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2009, a total of 1,690,592 unit awards remain unvested, for which ETP expects to recognize a total of $50.9 million in compensation expense over a weighted average period of 1.9 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by an ETE officer, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officer. These rights include the economic benefits of ownership of these ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE.

During the years ended December 31, 2008 and August 31, 2007, unvested rights related to 450,000 ETE common units and 675,000 ETE common units, respectively, with aggregate grant-date fair values of $10.3 million and $23.5 million, respectively, were awarded to ETP officers. During the year ended December 31, 2008, unvested rights related to 240,000 ETE common units were forfeited. During the years ended December 31, 2009 and 2008 and the four months ended December 31, 2007, ETP officers vested in rights related to 165,000 ETE common units, 135,000 ETE common units, and 55,000 ETE common units, respectively, with aggregate fair values upon vesting of $4.6 million, $3.5 million, and $1.9 million, respectively.

ETP is recognizing non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded the ETP employees assuming no forfeitures. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, ETP recognized non-cash compensation expense, net of forfeitures, of $6.4 million, $3.5 million, $3.6 million and $5.2 million, respectively, as a result of these awards.

As of December 31, 2009, rights related to 530,000 ETE common units remain outstanding, for which we expect to recognize a total of $6.8 million in compensation expense over a weighted average period of 1.9 years.

8. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Current expense (benefit):				
Federal	$ (8,851)	$ (180)	$ 2,990	$ 7,896
State	9,662	12,216	5,705	9,803
Total	811	12,036	8,695	17,699
Deferred expense (benefit):				
Federal	11,541	(5,634)	1,482	(4,598)
State	425	278	612	557
Total	11,966	(5,356)	2,094	(4,041)
Total income tax expense (benefit)	$ 12,777	$ 6,680	$ 10,789	$ 13,658

On May 18, 2006, the State of Texas enacted House Bill 3, which replaced the existing state franchise tax with a “margin tax.” In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin, which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law’s effective date of January 1, 2007. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $8.5 million, $10.5 million, $3.9 million and $6.9 million, respectively.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. The difference between the statutory rate and the effective rate is summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate, net of federal benefit	1.03%	1.25%	1.82%	1.25%
Earnings not subject to tax at the Partnership level	(34.44)%	(35.48)%	(32.86)%	(34.25)%
Effective tax rate	1.59%	0.77%	3.96%	2.00%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the deferred tax liability were as follows:

	December 31, 2009	December 31, 2008
Property, plant and equipment	$ 112,707	$ 105,032
Other, net	290	(3,846)
Total deferred tax liability	112,997	101,186
Less current deferred tax liability	—	589
Total long-term deferred tax liability	$ 112,997	$ 100,597

9. MAJOR CUSTOMERS AND SUPPLIERS:

Our major customers are in our natural gas operations. Our natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while our NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively. Management believes that our portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer accounted for 10% or more of our consolidated revenue.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Propane segments				
Unaffiliated:				
M.P. Oils, Ltd.	15.1%	14.9%	14.2%	20.7%
Targa Liquids	14.3%	15.0%	15.9%	22.6%
Affiliated:				
Enterprise	50.3%	50.7%	50.6%	22.1%

Enterprise GP Holdings, L.P. and its subsidiaries (“Enterprise” or “EPE”) became related parties on May 7, 2007 as discussed in Note 13. Titan purchases the majority of its propane from Enterprise pursuant to an agreement that expires in March 2010 and contains renewal and extension options.

We sold our investment in M-P Energy in October 2007. In connection with the sale, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

This concentration of suppliers may impact our overall operations either positively or negatively. However, management believes that the diversification of suppliers is sufficient to enable us to purchase all of our supply needs at market prices without a material disruption of operations if supplies are interrupted from any of our existing sources. Although no assurances can be given that supplies of natural gas, propane and NGLs will be readily available in the future, we expect a sufficient supply to continue to be available.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, ETP filed an application for FERC authority to construct and operate the Tiger pipeline. Approval from the FERC is still pending.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (“NGA”) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern’s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern’s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern’s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (“Order”). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service effective March 2009.

Guarantees

MEP Guarantee

ETP has guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the “MEP Facility”), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP’s guarantee may be proportionately increased or decreased if ETP’s ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both ETP’s credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP’s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

The commitment amount under the MEP Facility was originally $1.4 billion. In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by ETP or KMP. In October 2009, the members made additional capital contributions to MEP, which MEP used to further reduce the outstanding borrowings under the MEP Facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275.0 million.

As of December 31, 2009, MEP had $29.5 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to ETP’s 50% guarantee of MEP’s outstanding borrowings and letters of credit were $14.7 million and $16.6 million, respectively, as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.3%.

Although ETP transferred substantially all of its interest in MEP on May 26, 2010, as discussed above in “Recent Developments” at Note 1, ETP will continue to guarantee 50% of MEP’s obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify ETP for any costs related to the guarantee of payments under this facility.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the “FEP Facility”). ETP has guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP’s guarantee may be proportionately increased or decreased if ETP’s ownership percentage increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both ETP’s credit rating and that of KMP, with a maximum fee of 1.0%.

As of December 31, 2009, FEP had $355.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to ETP’s 50% guarantee of FEP’s outstanding borrowings was $177.5 million as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $19.8 million, $17.2 million, $9.4 million and $33.2 million for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, respectively.

Future minimum lease commitments for such leases are:

2010	$ 27,216
2011	24,786
2012	22,522
2013	20,385
2014	17,907
Thereafter	214,088

We have forward commodity contracts, which are expected to be settled by physical delivery. Short-term contracts, which expire in less than one year require delivery of up to 390,564 MMBtu/d. Long-term contracts require delivery of up to 125,551 MMBtu/d and extend through May 2014.

During fiscal year 2007, we entered into a long-term agreement with CenterPoint Energy Resources Corp (“CenterPoint”) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of the agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel storage facility.

We have a transportation agreement with TXU Portfolio Management Company, LP (“TXU Shipper”) to transport a minimum of 100,000 MMBtu per year through 2012. We also have two natural gas storage agreements with TXU Shipper to store gas at two natural gas facilities that are part of the ET Fuel System that expire in 2012. As of December 31, 2009 and 2008 and August 31, 2007, respectively, the Partnership was entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month periods ended each May 31st. As a result, the Partnership recognized approximately $11.7 million, $10.7 million and $10.8 million in additional fees during the second quarters of 2009 and 2008 and the third fiscal quarter of 2007, respectively.

We have signed long-term agreements with several parties committing firm transportation volumes into the East Texas pipeline. Those commitments include an agreement with XTO Energy Inc. (“XTO”) to deliver approximately 200,000 MMBtu/d of natural gas into the pipeline that expires in June 2012. Exxon Mobil Corporation (“ExxonMobil”) and XTO announced an agreement whereby ExxonMobil will acquire XTO. The pending acquisition, expected to be completed in the second quarter of 2010, is not expected to result in any changes to these commitments.

We also have two long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts require an aggregated capacity of approximately 238,000 MMBtu/d of natural gas and extend through 2011.

Titan has a purchase contract with Enterprise (see Note 13) to purchase the majority of Titan’s propane requirements. The contract continues until March 2010 and contains renewal and extension options. The contract contains various service level agreements between the parties.

In connection with the sale of our investment in M-P Energy in October 2007, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

We have commitments to make capital contributions to our joint ventures, for which we expect to make capital contributions of between $90 million and $105 million during 2010.

Litigation and Contingencies

The Operating Companies may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us and our Operating Companies from material expenses related to product liability, personal injury or property damage in the future.

FERC and Related Matters. On July 26, 2007, the FERC issued to ETP an Order to Show Cause and Notice of Proposed Penalties (the “Order and Notice”) that contains allegations that ETP violated FERC rules and regulations. The FERC alleged that ETP engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from ETP’s commodities derivatives positions and from certain of ETP’s index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods ETP violated the FERC’s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that ETP violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of ETP’s intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that ETP manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC’s Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP’s trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC’s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, ETP entered into a settlement agreement with the FERC’s Enforcement Staff with respect to the pending FERC claims against ETP and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against ETP and provides that ETP make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against ETP by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement ETP does not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with ETP’s alleged conduct related to the FERC claims. The settlement agreement also requires ETP to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ's recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ's fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, ETP remains a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The plaintiff appealed this determination to the First Court of Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010 the First Circuit Court of Appeals issued an opinions affirming the judgment of the lower court granting ETP's motion for summary judgment.

In October 2007, a consolidated class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, ETP had the market power to manipulate index prices, and that ETP used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit ETP's natural gas physical and financial trading positions, and that ETP intentionally submitted price and volume trade information to trade publications. This complaint also alleges that ETP violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by ETP manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, ETP filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, ETP filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint.

On March 17, 2008, a second class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period ETP exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit its own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, ETP filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. ETP opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted ETP's motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

ETP is expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. ETP record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, ETP made the $5.0 million payment and established the $25.0 million fund in October 2009. ETP expects the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which ETP expects to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount ETP becomes obligated to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, ETP will review the amount of our accrual related to these matters as developments related to these matters occur and ETP will adjust its accrual if ETP determines that it is probable that the amount it may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As ETP's accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce ETP's cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, ETP may experience a material adverse impact on its results of operations and our liquidity.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were defendants in litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the "Cushion Gas Litigation". In 2004, ETC OLP (a subsidiary of (ETP) acquired the HPL Entities from AEP, and due to the potential liability of the HPL Entities pursuant to the Cushion Gas Litigation, AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. AEP is appealing the court decision. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A pursuant to this court decision.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of December 31, 2009 and 2008, accruals of approximately $11.1 million and $8.5 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of December 31, 2008, an accrual of $21.0 million was recorded as accrued and other current liabilities and other non-current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters, and we did not have any such accruals as of December 31, 2009.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.6 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the EPA’s Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the “EPA”) regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to HOLP, it is believed that HOLP’s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2009 or our December 31, 2008 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of December 31, 2009 and 2008, accruals on an undiscounted basis of $12.6 million and $13.3 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for all of the above environmental matters is adequate to cover the potential exposure for clean-up costs.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT") under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as ("high consequence areas.") Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

11. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

See Note 2 for further discussion of our accounting for derivative instruments and hedging activities.

Commodity Price Risk

The following table details the outstanding commodity-related derivatives:

		December 31, 2009		December 31, 2008	
	Commodity	Notional Volume MMBtu	Maturity	Notional Volume MMBtu	Maturity
Mark to Market Derivatives					
Basis Swaps IFERC/NYMEX	Gas	72,325,000	2010-2011	15,720,000	2009-2011
Swing Swaps IFERC	Gas	(38,935,000)	2010	(58,045,000)	2009
Fixed Swaps/Futures	Gas	4,852,500	2010-2011	(20,880,000)	2009-2010
Options - Puts	Gas	2,640,000	2010	—	N/A
Options - Calls	Gas	(2,640,000)	2010	—	N/A
Forwards/Swaps - in Gallons	Propane/Ethane	6,090,000	2010	47,313,002	2009
Fair Value Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(22,625,000)	2010	—	N/A
Fixed Swaps/Futures	Gas	(27,300,000)	2010	—	N/A
Hedged Item - Inventory	Gas	27,300,000	2010	—	N/A
Cash Flow Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(13,225,000)	2010	(9,085,000)	2009
Fixed Swaps/Futures	Gas	(22,800,000)	2010	(9,085,000)	2009
Forwards/Swaps - in Gallons	Propane/Ethane	20,538,000	2010	—	N/A

We expect gains of $2.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the consolidated statements of operations on a net basis. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the year ended December 31, 2008, net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007 and net gains of approximately $2.2 million for the fiscal year ended August 31, 2007. There were no gains or losses associated with trading activities during the year ended December 31, 2009.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We have previously managed a portion of our current and future interest rate exposures by utilizing interest rate swaps. As of December 31, 2009, we do not have any interest rate swaps outstanding.

In December 2009, we settled forward starting swaps with notional amounts of $500.0 million for a cash payment of $11.1 million. In April 2009, we terminated forward starting swaps with notional amounts of $100.0 million and $150.0 million for an insignificant amount.

In January 2010, we entered into interest rate swaps with notional amounts of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate that mature in July 2013 and February 2015, respectively. These swaps hedge against changes in the fair value of our fixed rate debt.

Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of December 31, 2009 and December 31, 2008:

	Balance Sheet Location	Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
		December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Derivatives designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 669	$ 10,665	$ (24,035)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	8,443	918	(201)	(119)
Total derivatives designated as hedging instruments		$ 9,112	$ 11,583	$ (24,236)	$ (1,623)
Derivatives not designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	72,851	432,614	(36,950)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	3,928	17,244	(241)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	—	—	—	(51,643)
Total derivatives not designated as hedging instruments		$ 76,779	$ 449,858	$ (37,191)	$ (443,282)
Total derivatives		$ 85,891	$ 461,441	$ (61,427)	$ (444,905)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets. ETP had net deposits with counterparties of $79.7 million and $78.2 million as of December 31, 2009 and December 31, 2008, respectively.

The following tables detail the effect of the Partnership's derivative assets and liabilities in the consolidated statements of operations for the periods presented:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 3,143	$ 17,461	$ 21,406	$ 181,765
Interest Rate Swap Derivatives	Interest Expense	—	—	—	(4,719)
Total		$ 3,143	$ 17,461	$ 21,406	$ 177,046

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 9,924	$ 42,874	$ 8,673	$ 162,340
Interest Rate Swap Derivatives	Interest Expense	287	646	(51)	920
Total		$ 10,211	$ 43,520	$ 8,622	$ 163,260

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ —	$ (8,347)	$ 8,472	$ 183
Interest Rate Swap Derivatives	Interest Expense	—	—	—	(1,813)
Total		$ —	$ (8,347)	$ 8,472	$ (1,630)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in fair value hedging relationships:					
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ 60,045	$ —	$ —	$ —
Total		$ 60,045	$ —	$ —	$ —

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives not designated as hedging instruments:					
Commodity Derivatives	Cost of Products Sold	$ 99,807	$ 12,478	$ 9,886	$ 30,028
Trading Commodity Derivatives	Revenue	—	(28,283)	(2,298)	5,228
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	39,239	(50,989)	(1,013)	31,032
Total		$139,046	$(66,794)	$ 6,575	$ 66,288

We recognized an $18.6 million unrealized loss, a $35.5 million unrealized gain, a $13.2 million unrealized gain and an $8.5 million unrealized loss on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships and amounts classified as trading activity) for the years ended December 31, 2009 and 2008, four months ended December 31, 2007 and the year August 31, 2007, respectively. In addition, for the year ended December 31, 2009, we recognized unrealized gains of $48.6 million on commodity derivatives and related hedged inventory accounted for as fair value hedges. There were no unrealized gains or losses on fair value hedging commodity derivatives in the prior years since we commenced fair hedge accounting on our storage inventory in April 2009.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

12. <u>RETIREMENT BENEFITS</u>:

ETP sponsors a 401(k) savings plan, which covers virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. Prior to 2009, employer matching contributions were discretionary. We made matching contributions of $9.8 million, $9.7 million, $2.6 million and $8.5 million to the 401(k) savings plan for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively.

13. <u>RELATED PARTY TRANSACTIONS</u>:

On May 7, 2007, Ray Davis, previously the Co-Chairman of ETE and Co-Chairman and Co-Chief Executive Officer of ETP (retired August 15, 2007), and Natural Gas Partners VI, L.P. ("NGP") and affiliates of each, sold approximately 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise. In addition to the purchase of ETE Common Units, Enterprise acquired a non-controlling equity interest in ETE's General Partner, LE GP, LLC ("LE GP"). As a result of these transactions, EPE and its subsidiaries are considered related parties for financial reporting purposes.

On December 23, 2009, Dan L. Duncan and Ralph S. Cunningham were appointed as directors of ETE's general partner. Mr. Duncan is Chairman and a director of EPE Holdings, LLC, the general partner of Enterprise;

Chairman and a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., or EPD; and Group Co-Chairman of EPCO, Inc. TEPPCO Partners, L.P., or TEPPCO, is also an affiliate of EPE. Dr. Cunningham is the President and Chief Executive Officer of EPE Holdings, LLC, the general partner of Enterprise. These entities and other affiliates of Enterprise are referred to herein collectively as the “Enterprise Entities.” Mr. Duncan directly or indirectly beneficially owns various interests in the Enterprise Entities, including various general partner interests and approximately 77.1% of the common units of Enterprise and approximately 34% of the common units of EPD. On October 26, 2009, TEPPCO became a wholly owned subsidiary of Enterprise.

Our propane operations routinely enter into purchases and sales of propane with certain of the Enterprise Entities, including purchases under a long-term contract of Titan to purchase the majority of its propane requirements through certain of the Enterprise Entities. This agreement was in effect prior to our acquisition of Titan in 2006, and expires in March 2010 and contains renewal and extension options.

From time to time, our natural gas operations purchase from, and sell to, the Enterprise Entities natural gas and NGLs, in the ordinary course of business. We have a monthly natural gas storage contract with TEPPCO. Our natural gas operations and the Enterprise Entities transport natural gas on each other’s pipelines and share operating expenses on jointly-owned pipelines.

The following table presents sales to and purchases from affiliates of Enterprise. Amounts reflected below for the year ended August 31, 2007 include transactions beginning on May 7, 2007, the date Enterprise became an affiliate. Volumes are presented in thousands of gallons for propane and NGLs and in billions of Btus for natural gas:

		Years Ended December 31,				Four Months Ended December 31,		Year Ended August 31,	
		2009		2008		2007		2007	
	Product	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars
Propane Operations:									
Sales	Propane	20,370	$ 14,046	13,230	$ 19,769	2,982	$ 4,619	1,470	$ 1,725
	Derivatives	—	5,915	—	2,442	—	1,857	—	22
Purchases	Propane	307,525	$305,148	318,982	$472,816	125,141	$192,580	61,660	$74,688
	Derivatives	—	38,392	—	20,993	—	—	—	1
Natural Gas Operations:									
Sales	NGLs	477,908	$374,020	58,361	$ 96,974	3,240	$ 4,726	464	$ 648
	Natural Gas	11,532	44,212	6,256	52,205	2,036	11,452	1,495	9,768
	Fees	—	(3,899)	—	5,093	—	610	—	—
Purchases	Natural Gas Imbalances	176	$ 1,164	3,488	$ (6,485)	313	$ (911)	3,120	$22,677
	Natural Gas	10,561	49,559	13,457	120,837	3,577	23,341	1,541	7,501
	Fees	—	(2,195)	—	876	—	311	—	—

As of December 31, 2009 and 2008, Titan had forward mark-to-market derivatives for approximately 6.1 million and 45.2 million gallons of propane at a fair value asset of $3.3 million and a fair value liability of $40.1 million, respectively, with Enterprise. In addition, as of December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 20.5 million gallons of propane at a fair value asset of $8.4 million with Enterprise.

The following table summarizes the related party balances with Enterprise on our consolidated balance sheets:

	December 31, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 47,005	$ 11,558
Accounts payable	3,518	567
Imbalance payable	694	(547)
Propane Operations:		
Accounts receivable	$ 3,386	$ 111
Accounts payable	31,642	33,308

Accounts receivable from related companies excluding Enterprise consist of the following:

	December 31, 2009	December 31, 2008
ETE	$ 5,255	$ 2,632
MEP	632	2,805
McReynolds Energy	—	202
Energy Transfer Technologies, Ltd.	—	16
Others	870	449
Total accounts receivable from related companies excluding Enterprise	$ 6,757	$ 6,104

Effective August 17, 2009, ETP acquired 100% of the membership interests of Energy Transfer Group, L.L.C. ("ETG"), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. ("ETT"). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of our General Partner's general partner and the other of which is controlled by a member of ETP's management. In exchange, the former members acquired the right to receive (in cash or Common Units), future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG may receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

Prior to our acquisition of ETG in August 2009, our natural gas midstream and intrastate transportation and storage operations secured compression services from ETT. The terms of each arrangement to provide compression services were, in the opinion of independent directors of the General Partner, no more or less favorable than those available from other providers of compression services. During the years ended December 31, 2009 (through the ETG acquisition date) and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, we made payments totaling $3.4 million, $9.4 million, $0.8 million and $2.4 million, respectively, to ETG for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations.

The Chief Executive Officer ("CEO") of our General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. We recorded non-cash compensation expense and an offsetting capital contribution of $1.3 million ($0.5 million in salary and $0.8 million in accrued bonuses) for each of the years ended December 31, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

14. <u>COMPARATIVE INFORMATION FOR THE FOUR MONTHS ENDED DECEMBER 31, 2007</u>:

The unaudited financial information for the four month period ended December 31, 2006, contained herein is presented for comparative purposes only and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America. Certain financial statement amounts have been adjusted due to the adoption of new accounting standards in 2009. See Note 2.

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
REVENUES:		
Natural gas operations	$ 1,832,192	$ 1,668,667
Retail propane	471,494	409,821
Other	45,824	83,978
Total revenues	2,349,510	2,162,466
COSTS AND EXPENSES:		
Cost of products sold - natural gas operations	1,343,237	1,382,473
Cost of products sold - retail propane	315,698	256,994
Cost of products sold - other	14,719	50,376
Operating expenses	221,757	173,365
Depreciation and amortization	71,333	48,767
Selling, general and administrative	59,167	40,638
Total costs and expenses	2,025,911	1,952,613
OPERATING INCOME	323,599	209,853
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(66,304)	(54,953)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other, net	1,065	2,163
INCOME BEFORE INCOME TAX EXPENSE	272,576	164,018
Income tax expense	10,789	3,120
NET INCOME	261,787	160,898
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	170,812	87,731
NET INCOME ATTRIBUTABLE TO PARTNERS	90,975	73,167
GENERAL PARTNER'S INTEREST IN NET INCOME	9	7
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 90,966	$ 73,160

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
Net income	$ 261,787	$ 160,898
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17,269)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	21,626	152,653
Change in value of available-for-sale securities	(98)	(401)
	4,259	128,554
Comprehensive income	266,046	289,452
Less: Comprehensive income attributable to noncontrolling interest	174,986	213,714
Comprehensive income attributable to partners	$ 91,060	$ 75,738

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 261,787	$ 160,898
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	71,333	48,767
Amortization of finance costs charged to interest	1,435	1,068
Provision for loss on accounts receivable	544	563
Non-cash unit-based compensation expense	8,114	4,385
Non-cash executive compensation expense	442	—
Deferred income taxes	1,003	(2,234)
(Gains) losses on disposal of assets	(14,310)	(2,212)
Distributions in excess of (less than) equity in earnings of affiliates, net	4,448	(4,743)
Other non-cash	(2,069)	(76)
Net change in operating assets and liabilities, net of effects of acquisitions	(90,574)	238,989
Net cash provided by operating activities	242,153	445,405
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash paid for (received in) acquisitions	(337,092)	(67,089)
Capital expenditures	(651,228)	(336,473)
Contributions in aid of construction costs	3,493	4,984
(Advances to) repayments from affiliates, net	(32,594)	(953,247)
Proceeds from the sale of assets	21,478	7,644
Net cash used in investing activities	(995,943)	(1,344,181)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,741,547	1,667,810
Principal payments on debt	(1,062,272)	(1,737,788)
Subsidiary equity offerings, net of issue costs	234,887	1,200,000
Distributions to partners	(59,316)	(42,609)
Distributions to noncontrolling interests	(113,080)	(83,165)
Debt issuance costs	(211)	(9,451)
Net cash provided by financing activities	741,555	994,797
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(12,235)	96,021
CASH AND CASH EQUIVALENTS, beginning of period	68,750	26,070
CASH AND CASH EQUIVALENTS, end of period	$ 56,515	$ 122,091

15. **SUPPLEMENTAL INFORMATION:**

Following are the financial statements of the Partnership, which are included to provide additional information with respect to the Partnership's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS
(Dollars in thousands)

	December 31, 2009	December 31, 2008
CURRENT ASSETS:		
Cash and cash equivalents	$ 71	$ 60
Other current assets	49	61
Total current assets	120	121
INVESTMENT IN ENERGY TRANSFER PARTNERS	174,834	161,038
GOODWILL	29,588	29,588
OTHER ASSETS	150	199
Total assets	$ 204,692	$ 190,946
CURRENT LIABILITIES:		
Accounts payable to related companies	$ 220	$ 126
Interest payable	6	6
Current maturities of long-term debt	37	34
Total current liabilities	263	166
LONG-TERM DEBT, less current maturities	129	166
	392	332
PARTNERS' CAPITAL:		
General partner	18	16
Limited partners:		
Class A Limited Partner interests	107,515	92,313
Class B Limited Partner interests	96,638	98,227
Accumulated other comprehensive income	129	58
Total partners' capital	204,300	190,614
Total liabilities and partners' capital	$ 204,692	$ 190,946

STATEMENTS OF OPERATIONS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
SELLING, GENERAL AND ADMINISTRATIVE EXPENSES	$ 18	$ —	$ 35	$ 98
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(97)	(17)	(6)	(19)
Equity in earnings (losses) of affiliates	365,362	315,895	91,012	235,875
Other, net	(322)	(137)	4	16
NET INCOME	$ 364,925	$ 315,741	$ 90,975	$ 235,774

STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 351,380	$ 299,053	$ 59,320	$ 205,693
CASH FLOWS FROM FINANCING ACTIVITIES:				
Principal payments on debt	(34)	(31)	—	(29)
Distributions to partners	(351,335)	(299,011)	(59,316)	(205,648)
Net cash used in financing activities	(351,369)	(299,042)	(59,316)	(205,677)
INCREASE IN CASH AND CASH EQUIVALENTS	11	11	4	16
CASH AND CASH EQUIVALENTS, beginning of period	60	49	45	29
CASH AND CASH EQUIVALENTS, end of period	$ 71	$ 60	$ 49	$ 45

Exhibit 99.4

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 78,879	$ 68,253
Marketable securities	3,002	6,055
Accounts receivable, net of allowance for doubtful accounts of $6,378 and $6,338 as of June 30, 2010 and December 31, 2009, respectively	471,288	566,522
Accounts receivable from related companies	49,362	57,148
Inventories	231,057	389,954
Exchanges receivable	9,985	23,136
Price risk management assets	24	12,371
Other current assets	91,161	148,423
Total current assets	934,758	1,271,862
PROPERTY, PLANT AND EQUIPMENT	10,329,313	9,649,405
ACCUMULATED DEPRECIATION	(1,126,660)	(979,158)
	9,202,653	8,670,247
ADVANCES TO AND INVESTMENTS IN AFFILIATES	7,587	663,298
LONG-TERM PRICE RISK MANAGEMENT ASSETS	4,237	—
GOODWILL	803,334	775,093
INTANGIBLES AND OTHER ASSETS, net	433,171	384,109
Total assets	$ 11,385,740	$ 11,764,609

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 315,601	$ 358,997
Accounts payable to related companies	7,623	38,842
Exchanges payable	11,323	19,203
Price risk management liabilities	2,248	442
Accrued and other current liabilities	459,146	365,175
Current maturities of long-term debt	40,733	40,923
Total current liabilities	836,674	823,582
LONG-TERM DEBT, less current maturities	6,049,531	6,177,046
OTHER NON-CURRENT LIABILITIES	134,385	134,807
COMMITMENTS AND CONTINGENCIES (Note 12)		
PARTNERS' CAPITAL:		
General Partner	18	18
Limited Partners:		
Class A Limited Partner interests	96,396	107,515
Class B Limited Partner interests	105,082	96,638
Accumulated other comprehensive income	297	129
Total partners' capital	201,793	204,300
Noncontrolling interest	4,163,357	4,424,874
Total equity	4,365,150	4,629,174
Total liabilities and equity	$ 11,385,740	$ 11,764,609

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)
(unaudited)

	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
REVENUES:				
Natural gas operations	$1,045,946	$ 948,233	$2,352,655	$2,060,188
Retail propane	197,147	179,770	730,586	667,677
Other	24,613	23,814	56,446	54,052
Total revenues	1,267,706	1,151,817	3,139,687	2,781,917
COSTS AND EXPENSES:				
Cost of products sold — natural gas operations	654,239	542,004	1,566,845	1,274,117
Cost of products sold — retail propane	110,282	78,070	415,263	298,292
Cost of products sold — other	6,336	5,919	13,614	12,723
Operating expenses	169,533	176,681	340,281	358,454
Depreciation and amortization	83,877	76,174	167,153	148,777
Selling, general and administrative	44,254	53,748	93,026	109,492
Total costs and expenses	1,068,521	932,596	2,596,182	2,201,855
OPERATING INCOME	199,185	219,221	543,505	580,062
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(103,017)	(100,680)	(207,982)	(182,729)
Equity in earnings of affiliates	4,072	1,673	10,253	2,170
Gains (losses) on disposal of assets	1,385	181	(479)	(245)
Gains on non-hedged interest rate derivatives	—	36,842	—	50,568
Allowance for equity funds used during construction	4,298	(1,839)	5,607	18,588
Impairment of investment in affiliate	(52,620)	—	(52,620)	—
Other, net	(5,893)	(182)	(4,936)	870
INCOME BEFORE INCOME TAX EXPENSE	47,410	155,216	293,348	469,284
Income tax expense	4,569	4,559	10,493	11,491
NET INCOME	42,841	150,657	282,855	457,793
LESS: NET INCOME (LOSS) ATTRIBUTABLE TO NONCONTROLLING INTEREST	(47,756)	63,559	92,356	280,436
NET INCOME ATTRIBUTABLE TO PARTNERS	90,597	87,098	190,499	177,357
GENERAL PARTNER’S INTEREST IN NET INCOME	10	9	19	18
LIMITED PARTNERS’ INTEREST IN NET INCOME	$ 90,587	$ 87,089	$ 190,480	$ 177,339

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	$ 42,841	$ 150,657	$282,855	$457,793
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(6,112)	856	(12,618)	(9,693)
Change in value of derivative instruments accounted for as cash flow hedges	(9,452)	1,336	24,634	(50)
Change in value of available-for-sale securities	(724)	3,657	(3,053)	3,708
	(16,288)	5,849	8,963	(6,035)
Comprehensive income	26,553	156,506	291,818	451,758
Less: Comprehensive income (loss) attributable to noncontrolling interest	(63,769)	69,290	101,151	274,521
Comprehensive income attributable to partners	$ 90,322	$ 87,216	$190,667	$177,237

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF EQUITY

FOR THE SIX MONTHS ENDED JUNE 30, 2010

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partners	Accumulated Other Comprehensive Income	Noncontrolling Interest	Total
Balance, December 31, 2009	$ 18	$ 204,153	$ 129	$ 4,424,874	$4,629,174
Redemption of units in connection with MEP transaction	—	(3,700)	—	(608,339)	(612,039)
Distributions to partners	(19)	(189,467)	—	—	(189,486)
Subsidiary distributions	—	—	—	(342,325)	(342,325)
Subsidiary units issued for cash	—	—	—	574,522	574,522
Tax effect of remedial income allocation from tax amortization of goodwill	—	—	—	(1,702)	(1,702)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	—	—	14,563	14,563
Non-cash executive compensation		12	—	613	625
Other comprehensive income, net of tax	—	—	168	8,795	8,963
Net income	19	190,480	—	92,356	282,855
Balance, June 30, 2010	$ 18	$ 201,478	$ 297	$ 4,163,357	$4,365,150

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

ENERGY TRANSFER PARTNERS GP, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 886,147	$ 704,038
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(153,385)	(6,362)
Capital expenditures (excluding allowance for equity funds used during construction)	(608,497)	(512,534)
Contributions in aid of construction costs	7,957	2,349
Advances to affiliates, net of repayments	(5,596)	(364,000)
Proceeds from the sale of assets	9,124	5,033
Net cash used in investing activities	(750,397)	(875,514)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	265,642	1,587,943
Principal payments on debt	(410,178)	(1,501,487)
Subsidiary equity offerings, net of issue costs	574,522	578,924
Distributions to partners	(189,486)	(169,484)
Distributions to noncontrolling interests	(342,325)	(294,348)
Subsidiary redemption of units	(23,299)	—
Debt issuance costs	—	(7,746)
Net cash provided by (used in) financing activities	(125,124)	193,802
INCREASE IN CASH AND CASH EQUIVALENTS	10,626	22,326
CASH AND CASH EQUIVALENTS, beginning of period	68,253	91,962
CASH AND CASH EQUIVALENTS, end of period	$ 78,879	$ 114,288

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2009, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners GP, L.P., and its subsidiaries (the “Partnership,” “we” or “ETP GP”) as of June 30, 2010 and for the three and six months ended June 30, 2010 and 2009, have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for interim consolidated financial information. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership’s operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners GP, L.P. and its subsidiaries as of June 30, 2010, and the Partnership’s results of operations and cash flows for the three and six months ended June 30, 2010 and 2009. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of ETP GP and subsidiaries presented as Exhibit 99.3 to the Energy Transfer Equity, L.P. Form 8-K filed on August 11, 2010.

Certain prior period amounts have been reclassified to conform to the 2010 presentation. These reclassifications had no impact on net income or total equity.

ETP GP is the General Partner and the owner of the general partner interest of Energy Transfer Partners, L.P. (“ETP”), which is a 1.9% general partner interest as of June 30, 2010. ETP GP is owned 99.99% by its limited partners, and 0.01% by its general partner, Energy Transfer Partners, L.L.C. (“ETP LLC”). The condensed consolidated financial statements of the Partnership presented herein include ETP’s operating subsidiaries described below.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the “Operating Companies”) as follows:

- La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“ETC OLP”), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- Energy Transfer Interstate Holdings, LLC (“ET Interstate”), a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
    - Transwestern Pipeline Company, LLC (“Transwestern”), a Delaware limited liability company engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

- ETC Fayetteville Express Pipeline, LLC (“ETC FEP”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC (“ETC Tiger”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- ETC Compression, LLC (“ETC Compression”), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Heritage Operating, L.P. (“HOLP”), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan Energy Partners, L.P. (“Titan”), a Delaware limited partnership also engaged in retail propane operations.

The Partnership, the Operating Companies and their subsidiaries are collectively referred to in this report as “we,” “us,” “ETP GP,” or the “Partnership.”

Recent Developments

On May 26, 2010, ETP completed the transfer of the membership interests in ETC Midcontinent Express Pipeline III, L.L.C. (“ETC MEP III”) to ETE pursuant to the Redemption and Exchange Agreement between ETP and ETE, dated as of May 10, 2010 (the “MEP Transaction”). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC (“MEP”), ETP’s joint venture with Kinder Morgan Energy Partners, L.P. (“KMP”) that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, ETP redeemed 12,273,830 ETP common units that were previously owned by ETE. ETP also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. This closing adjustment is subject to change during a final review period as defined in the contribution agreement. ETP also granted ETE an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. (“ETC MEP II”). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of ETP interest in ETC MEP III, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP (“Regency”) in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc. (“GE EFS”).

ETP continues to guarantee 50% of MEP’s obligations under MEP’s $175.4 million senior revolving credit facility, with the remaining 50% of MEP’s obligations guaranteed by KMP; however, Regency has agreed to indemnify ETP for any costs related to the guaranty of payments under this facility. See Note 12.

2. ESTIMATES:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the operating results estimated for the three and six months ended June 30, 2010 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

3. ACQUISITIONS:

During the six months ended June 30, 2010, ETP purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, ETP recorded customer contracts of $68.2 million and goodwill of $27.3 million. See further discussion at Note 6.

4. CASH, CASH EQUIVALENTS AND SUPPLEMENTAL CASH FLOW INFORMATION:

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

Non-cash investing activities cash flow information are as follows:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 73,432	$ 90,268
Transfer of MEP joint venture interest in exchange for redemption of ETP Common Units	$ 588,741	$ —

5. INVENTORIES:

Inventories consisted of the following:

	June 30, 2010	December 31, 2009
Natural gas and NGLs, excluding propane	$ 89,751	$ 157,103
Propane	49,016	66,686
Appliances, parts and fittings and other	92,290	166,165
Total inventories	$231,057	$ 389,954

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. We designate commodity derivatives as fair value hedges for accounting purposes. Changes in fair value of the designated hedged inventory have been recorded in inventory on our condensed consolidated balance sheets and have been recorded in cost of products sold in our condensed consolidated statements of operations.

6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

A net increase in goodwill of $28.2 million was recorded during the six months ended June 30, 2010, primarily due to $27.3 million from the acquisition of the natural gas gathering company referenced in Note 3, which is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $68.2 million with useful lives of 46 years.

Components and useful lives of intangibles and other assets were as follows:

	June 30, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 245,574	$ (67,178)	$ 176,858	$ (58,761)
Noncompete agreements (3 to 15 years)	22,931	(12,578)	24,139	(12,415)
Patents (9 years)	750	(76)	750	(35)
Other (10 to 15 years)	1,320	(440)	478	(397)
Total amortizable intangible assets	270,575	(80,272)	202,225	(71,608)
Non-amortizable intangible assets — Trademarks	76,086	—	75,825	—
Total intangible assets	346,661	(80,272)	278,050	(71,608)
Other assets:				
Financing costs (3 to 30 years)	68,657	(29,104)	68,597	(24,774)
Regulatory assets	107,193	(12,508)	101,879	(9,501)
Other	32,544	—	41,466	—
Total intangibles and other assets	$ 555,055	$(121,884)	$ 489,992	$(105,883)

Aggregate amortization expense of intangible and other assets was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Reported in depreciation and amortization	$ 5,148	$ 4,983	$ 10,294	$ 9,692
Reported in interest expense	$ 2,165	$ 2,048	$ 4,330	$ 3,926

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2011	$26,915
2012	23,330
2013	17,899
2014	16,890
2015	14,566

7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at June 30, 2010 was $6.55 billion and $6.09 billion, respectively. At December 31, 2009, the aggregate fair value and carrying amount of long-term debt was $6.75 billion and $6.22 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2010 and December 31, 2009 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2010 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 3,002	$ 3,002	$ —
Interest rate derivatives	7,031	—	7,031
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	24	—	24
Swing Swaps IFERC	1,425	1,425	—
Fixed Swaps/Futures	1,045	1,045	—
Options — Puts	19,241	—	19,241
Total commodity derivatives	21,735	2,470	19,265
Total Assets	$ 31,768	$ 5,472	$ 26,296
Liabilities:			
Interest rate derivatives	$ (205)	$ —	$ (205)
Commodity derivatives:			
Natural Gas:			
Basic Swaps IFERC/NYMEX	(454)	(454)	—
Swing Swaps IFERC	(167)	—	(167)
Fixed Swaps/Futures	(181)	—	(181)
Options — Calls	(6,142)	—	(6,142)
Propane — Forwards/Swaps	(4,489)	—	(4,489)
Total commodity derivatives	(11,433)	(454)	(10,979)
Total Liabilities	$(11,638)	$ (454)	$(11,184)

	Fair Value Total	Fair Value Measurements at December 31, 2009 Using	
		Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 6,055	$ 6,055	$ —
Commodity derivatives	32,479	20,090	12,389
Liabilities:			
Commodity derivatives	(8,016)	(7,574)	(442)
Total	$30,518	$ 18,571	$ 11,947

In conjunction with the MEP Transaction, ETP adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of ETP's investment was transferred to ETE. See "Recent Developments" at Note 1.

8. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline, LLC

On May 26, 2010, ETP transferred to ETE, in exchange for ETP common units owned by ETE, substantially all of its interest in MEP. In conjunction with this transfer, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest to its estimated fair value. See discussion of the transaction in "Recent Developments" at Note 1.

Fayetteville Express Pipeline, LLC

ETP is party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Panola County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC ("FEP"), the entity formed to construct, own and operate this pipeline, received Federal Energy Regulatory Commission ("FERC") approval of its application for authority to construct and operate this pipeline. The pipeline is expected to have an initial capacity of 2.0 Bcf/d and is expected to be in service by the end of 2010. As of June 30, 2010, FEP has secured binding commitments for a minimum of 10 years for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America ("NGPL") in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

9. DEBT OBLIGATIONS:

Revolving Credit Facilities

ETP Credit Facility

ETP maintains a revolving credit facility (the "ETP Credit Facility") that provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of June 30, 2010, there was $29.3 million of borrowings outstanding under the ETP Credit Facility. Taking into account letters of credit of approximately $21.8 million, the amount available for future borrowings was $1.95 billion. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 0.95%.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility. At June 30, 2010, the HOLP credit facility had no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of June 30, 2010 was $74.5 million.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at June 30, 2010.

10. PARTNERS' CAPITAL:

Quarterly Distributions of Available Cash

Our distributions policy is consistent with the terms of the Partnership Agreement, which requires that we distribute all of our available cash quarterly. Our only cash-generating assets consist of partnership interests, including IDRs, from which we receive quarterly distributions from ETP. We have no independent operations outside of our interests in ETP. Under the Partnership Agreement, our distributions are characterized as the GP Distribution Amount and the IDR Distribution Amount. The GP Distribution Amount is all distributions we receive from ETP with respect to our General Partner Interest and the IDR Distribution Amount is all distributions received from ETP with respect to the IDR. Within 45 days following the end of each quarter, we will distribute all of our GP Available Cash and IDR Available Cash, as defined in the Partnership Agreement. GP Available Cash shall be distributed 99.99% to the Class A Limited Partners, pro rata and 0.01% to the General partner. IDR Available Cash shall be distributed 99.99% to the Class B Limited Partners, pro rata and 0.01% to the General Partner.

ETP GP has the right, in connection with the issuance of any equity security by ETP, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in ETP as ETP GP and its affiliates owned immediately prior to such issuance.

Contributions to Subsidiary

In order to maintain our general partner interest in ETP, ETP GP has previously been required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP.

In July 2009, ETP amended and restated its partnership agreement, and as a result, ETP GP is no longer required to make corresponding contributions to maintain its general partner interest in ETP.

We paid off our contribution payable to ETP of $8.9 million during the three months ended March 31, 2010.

Quarterly Distributions of Available Cash

On February 15, 2010, ETP paid a cash distribution for the three months ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on February 8, 2010.

On April 27, 2010, ETP paid a cash distribution for the three months ended March 31, 2010 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on May 7, 2010.

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at close of business on August 9, 2010.

The total amounts of distributions ETP GP received from ETP relating to its general partner interests and incentive distribution rights of ETP are as follows (shown in the period with respect to which they relate):

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
General Partner interest	$ 9,754	$ 9,720
Incentive Distribution Rights	184,751	168,311
Total distributions received from ETP	$ 194,505	$ 178,031

The total amounts of ETP distributions declared during the six months ended June 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Limited Partners:		
Common Units	$ 332,371	$ 301,738
Class E Units	6,242	6,242
General Partner Interest	9,754	9,720
Incentive Distribution Rights	184,751	168,311
Total distributions declared by ETP	$ 533,118	$ 486,011

Accumulated Other Comprehensive Income

The following table presents the components of accumulated other comprehensive income (“AOCI”), net of tax:

	June 30, 2010	December 31, 2009
Net gains on commodity related hedges	$ 14,353	$ 1,991
Net losses on interest rate hedges	(471)	(125)
Unrealized gains on available-for-sale securities	1,888	4,941
Noncontrolling interest	(15,473)	(6,678)
Total AOCI, net of tax	$ 297	$ 129

11. INCOME TAXES:

The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Current expense (benefit):				
Federal	$ 1,599	$ (771)	$ 2,917	$ (5,107)
State	4,248	3,377	7,421	6,895
Total	5,847	2,606	10,338	1,788
Deferred expense (benefit):				
Federal	(997)	2,041	421	9,142
State	(281)	(88)	(266)	561
Total	(1,278)	1,953	155	9,703
Total income tax expense	$ 4,569	$4,559	$10,493	$11,491
Effective tax rate	9.64%	2.94%	3.58%	2.45%

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level.

12. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, ETP filed an application for FERC authority to construct and operate the Tiger pipeline. The application was approved in April 2010 and construction began in June 2010. In February 2010, ETP announced a 400 MMcf/d expansion of the Tiger pipeline. In June 2010, ETP filed an application for FERC authority to construct, own and operate that expansion.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (“NGA”) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern’s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

Guarantees

MEP Guarantee

ETP has guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the “MEP Facility”), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although ETP transferred substantially all of its interest in MEP on May 26, 2010, as discussed above in “Recent Developments” at Note 1, ETP will continue to guarantee 50% of MEP’s obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify ETP for any costs related to the guarantee of payments under this facility.

Subject to certain exceptions, ETP’s guarantee may be proportionately increased or decreased if its ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP’s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of June 30, 2010, MEP had $33.1 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility, respectively. ETP's contingent obligations with respect to its 50% guarantee of MEP's outstanding borrowings and letters of credit were $16.6 million and $16.6 million, respectively, as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 1.4%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the "FEP Facility"). ETP has guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP's guarantee may be proportionately increased or decreased if ETP's ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012 and amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both ETP's credit rating and that of KMP, with a maximum fee of 1.0%.

As of June 30, 2010, FEP had $663.0 million of outstanding borrowings issued under the FEP Facility and ETP's contingent obligation with respect to its 50% guarantee of FEP's outstanding borrowings was $331.5 million as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts. In addition, we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a contract to purchase not less than 90.0 million gallons of propane per year that expires in 2015. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.4 million and $5.5 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, rental expense for operating leases totaled approximately $11.3 million and $11.5 million, respectively.

Our propane operations have an agreement with Enterprise GP Holdings L.P. ("Enterprise") (see Note 14) to supply a portion of our propane requirements. The agreement expired in March 2010 and our propane operations executed a five year extension as of April 2010. The extension will continue until March 2015 and includes an option to extend the agreement for an additional year.

We have commitments to make capital contributions to our joint ventures. For the joint ventures that we currently have interests in, we expect that capital contributions for the remainder of 2010 will be between $20 million and $30 million.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

FERC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the "Order and Notice") that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC's then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP's trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against us by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ's recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ's fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, ETP remains a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The Plaintiff appealed this determination to the First Court of Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010, the First Circuit Court of Appeals issued an opinion affirming the judgment of the lower court granting ETP's motion for summary judgment. No motion for rehearing was timely filed.

In October 2007, a consolidated class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint. No petition for rehearing was timely filed.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted our motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obligated to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations and our liquidity.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the “HPL Entities”), their parent companies and American Electric Power Corporation (“AEP”), were defendants in litigation with Bank of America (“B of A”) that related to AEP’s acquisition of HPL in the Enron bankruptcy and B of A’s financing of cushion gas stored in the Bammel storage facility (“Cushion Gas”). This litigation is referred to as the “Cushion Gas Litigation.” In 2004, ETC OLP (a subsidiary of (ETP) acquired the HPL Entities from AEP, at which time AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A under to this court decision.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of June 30, 2010 and December 31, 2009, accruals of approximately $11.4 million and $11.1 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

No amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters and deductibles.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that can require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline, gathering, treating, compressing, bending and processing business. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage, and to limit the financial liability, which could result from such events. However, the risk of environmental or other damage is inherent in transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in clean-up technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of June 30, 2010 and December 31, 2009, accruals on an undiscounted basis of $12.5 million and $12.6 million, respectively, were recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for clean-up costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean-up activities include remediation of several compressor sites on the Transwestern system for historical contamination associated with polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.5 million, which is included in the aggregate environmental accruals. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the U.S. Environmental Protection Agency’s (the “EPA”) Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

By March 2013, the Texas Commission on Environmental Quality is required to develop another plan to address the recent change in the ozone standard from 0.08 parts per million, or ppm, to 0.075 ppm and the U.S Environmental Protection Agency, or EPA, recently proposed lowering the standard even further, to somewhere in between 0.06 and 0.07 ppm. These efforts may result in the adoption of new regulations that may require additional nitrogen oxide emissions reductions.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation (“DOT”) under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as “high consequence areas.” Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended June 30, 2010 and 2009, $3.6 million and $11.6 million, respectively, of capital costs and $4.4 million and $5.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the six months ended June 30, 2010 and 2009, $5.0 million and $15.3 million, respectively, of capital costs and $6.3 million and $9.0 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act, also known as OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our operations as follows:

- Derivatives are utilized in our midstream operations in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage and interstate operations to hedge the sales price of retention and operational gas sales and hedge location price differentials related to the transportation of natural gas.
- Our propane operations permit customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread, through either mark-to-market or the physical withdrawal of natural gas.

The recent adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Part II, Item 1A. Risk Factors of this Form 10-Q.

We are also exposed to market risk on gas we retain for fees in our intrastate transportation and storage operations and operational gas sales on our interstate transportation operations. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

The following table details the outstanding commodity-related derivatives:

	June 30, 2010		December 31, 2009	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(23,182,500)	2010-2011	72,325,000	2010-2011
Swing Swaps IFERC (MMBtu)	(23,592,500)	2010-2011	(38,935,000)	2010
Fixed Swaps/Futures (MMBtu)	(395,000)	2010-2011	4,852,500	2010-2011
Options — Puts (MMBtu)	(8,140,000)	2010-2011	2,640,000	2010
Options — Calls (MMBtu)	(5,920,000)	2010-2011	(2,640,000)	2010
Propane:				
Forwards/Swaps (Gallons)	—	—	6,090,000	2010
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(5,410,000)	2010-2011	(22,625,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,765,000)	2010-2011	(27,300,000)	2010
Hedged Item — Inventory (MMBtu)	18,765,000	2010	27,300,000	2010
Cash Flow Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(10,845,000)	2010-2011	(13,225,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,502,500)	2010-2011	(22,800,000)	2010
Options – Puts (MMBtu)	25,800,000	2011-2012	—	—
Options – Calls (MMBtu)	(25,800,000)	2011-2012	—	—
Propane:				
Forwards/Swaps (Gallons)	51,702,000	2010-2011	20,538,000	2010

We expect gains of $11.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps in order to achieve our desired mix of fixed and variable rate debt. We also utilize interest rate swaps to lock in the rate on a portion of our anticipated debt issuances. We have the following interest rate swaps outstanding as of June 30, 2010:

Term	Notional Amount	Type [1]	Hedge Designation
July 2013	$ 350,000	Pay a floating rate plus 3.75% and receive a fixed rate of 6.00%	Fair value
August 2012	200,000	Forward starting to pay a fixed rate of 3.80% and receive a floating rate	Cash flow

(1) Floating rates are based on LIBOR.

In May 2010, the Partnership terminated interest rate swaps with notional amounts of $750.0 million that were designated as fair value hedges. Proceeds from the swap termination were $15.4 million. In connection with the swap termination, $9.7 million of previously recorded fair value adjustments to the hedged long-term debt will be amortized as a reduction of interest expense through February 2015.

Derivative Summary

The following table provides a balance sheet overview of ETP’s derivative assets and liabilities as of June 30, 2010 and December 31, 2009:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2010	December 31, 2009	June 30, 2010	December 31, 2009
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$25,158	$ 669	$ (4,425)	$ (24,035)
Commodity derivatives	—	8,443	(4,625)	(201)
Interest rate derivatives	7,031	—	(205)	—
	32,189	9,112	(9,255)	(24,236)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	32,257	72,851	(37,877)	(36,950)
Commodity derivatives	24	3,928	(212)	(241)
	32,281	76,779	(38,089)	(37,191)
Total derivatives	$64,470	$ 85,891	$(47,344)	$ (61,427)

The commodity derivatives (margin deposits) are recorded in “Other current assets” on our condensed consolidated balance sheets. The remainder of the derivatives are recorded in “Price risk management assets/liabilities.”

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our condensed consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the condensed consolidated balance sheets. ETP had net deposits with counterparties of $44.4 million and $79.7 million as of June 30, 2010 and December 31, 2009, respectively.

The following tables detail the effect of ETP’s derivative assets and liabilities in the condensed consolidated statements of operations for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$(9,150)	$1,336	$24,957	$ (50)
Interest rate derivatives	(205)	—	(205)	—
Total	$(9,355)	$1,336	$24,752	$ (50)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ 7,058	$ (928)	$12,373	$ 9,549
Interest rate derivatives	Interest expense	71	72	142	144
Total		$ 7,129	$ (856)	$12,515	$ 9,693

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ (1,016)	$ —	$ 105	$ —
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ (1,016)	$ —	$ 105	$ —

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 6,417	$12,498	$ (967)	$ 12,498
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ 6,417	$12,498	$ (967)	$ 12,498

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$(21,295)	$ 5,138	$ 672	$ 56,576
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	—	36,842	—	50,568
Total		$(21,295)	$41,980	$ 672	$107,144

We recognized $36.5 million and $27.0 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended June 30, 2010 and 2009, respectively. We recognized $45.2 million and $46.1 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the six months ended June 30, 2010 and 2009, respectively.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our condensed consolidated balance sheet and recognized in net income or other comprehensive income.

14. RELATED PARTY TRANSACTIONS:

As discussed in "Recent Developments" in Note 1, Regency became a related party on May 26, 2010. Regency provides us with contract compression services. For the period from May 26, 2010 to June 30, 2010, we recorded costs of products sold of $0.7 million and operating expenses of $0.2 million related to transactions with Regency.

We and subsidiaries of Enterprise transport natural gas on each other's pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. The following table presents sales to and purchase from affiliates of Enterprise:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Natural Gas Operations:				
Sales	$ 130,526	$ 90,591	$ 275,246	$ 165,074
Purchases	6,936	2,688	13,533	16,346
Propane Operations:				
Sales	481	5,226	10,966	11,508
Purchases	52,415	41,005	218,179	176,223

Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that was extended until March 2015, and includes an option to extend the agreement for an additional year. As of December 31, 2009, Titan had forward mark-to-market derivatives for approximately 6.1 million gallons of propane at a fair value asset of $3.3 million with Enterprise. All of these forward contracts were settled as of June 30, 2010. In addition, as of June 30, 2010 and December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 51.7 million and 20.5 million gallons of propane at a fair value liability of $4.5 million and a fair value asset of $8.4 million, respectively, with Enterprise.

The following table summarizes the related party balances on our condensed consolidated balance sheets:

	June 30, 2010	December 31, 2009
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$41,451	$ 47,005
Propane Operations	181	3,386
Other	7,730	6,757
Total accounts receivable from related parties:	$49,362	$ 57,148
Accounts payable from related parties:		
Enterprise:		
Natural Gas Operations	$ 825	$ 3,518
Propane Operations	5,478	31,642
Other	1,320	3,682
Total accounts payable from related parties:	$ 7,623	$ 38,842

The net imbalance payable from Enterprise was $1.9 million and $0.7 million for June 30, 2010 and December 31, 2009, respectively.

15. OTHER INFORMATION:

The tables below present additional detail for certain balance sheet captions.

Other Current Assets

Other current assets consisted of the following:

	June 30, 2010	December 31, 2009
Deposits paid to vendors	$44,393	$ 79,694
Prepaid and other	46,768	68,729
Total other current assets	$91,161	$ 148,423

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2010	December 31, 2009
Interest payable	$133,314	$ 136,229
Customer advances and deposits	69,591	88,430
Accrued capital expenditures	73,432	46,134
Accrued wages and benefits	40,272	25,202
Taxes other than income taxes	72,041	23,294
Income taxes payable	9,811	3,401
Deferred income taxes	109	—
Other	60,576	42,485
Total accrued and other current liabilities	$459,146	$ 365,175

16. SUPPLEMENTAL INFORMATION:

Following are the financial statements of the Partnership, which are included to provide additional information with respect to the Partnership's financial position, results of operations and cash flows on a stand-alone basis:

CONDENSED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 71	$ 71
Other current assets	49	49
Total current assets	120	120
INVESTMENT IN ENERGY TRANSFER PARTNERS	172,272	174,834
GOODWILL	29,588	29,588
INTANGIBLES AND OTHER ASSETS, net	100	150
Total assets	$202,080	$ 204,692
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable to related companies	$ 159	$ 220
Interest payable	—	6
Current maturities of long-term debt	39	37
Total current liabilities	198	263
LONG-TERM DEBT, less current maturities	89	129
PARTNERS' CAPITAL:		
General Partner	18	18
Limited Partners:		
Class A Limited Partner interests	96,396	107,515
Class B Limited Partner interests	105,082	96,638
Accumulated other comprehensive income	297	129
Total partners' capital	201,793	204,300
Total liabilities and partners' capital	$202,080	$ 204,692

CONDENSED STATEMENTS OF OPERATIONS

(Dollars in thousands)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
SELLING, GENERAL AND ADMINISTRATIVE	$ —	$ —	$ 18	$ 12
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(3)	—	(6)	(4)
Equity in earnings of affiliates	90,599	87,179	190,598	177,469
Other, net	—	(81)	(76)	(96)
NET INCOME	$ 90,596	$ 87,098	$190,498	$177,357

CONDENSED STATEMENTS OF CASH FLOWS

(Dollars in thousands)
(unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 189,522	$ 169,494
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal payments on debt	(36)	—
Distributions to partners	(189,486)	(169,484)
Net cash provided by (used in) financing activities	(189,522)	(169,484)
INCREASE IN CASH AND CASH EQUIVALENTS	—	10
CASH AND CASH EQUIVALENTS, beginning of period	71	60
CASH AND CASH EQUIVALENTS, end of period	$ 71	$ 70

Exhibit 99.5

Report of Independent Registered Public Accounting Firm

Members
Energy Transfer Partners, L.L.C.

We have audited the accompanying consolidated balance sheets of Energy Transfer Partners, L.L.C. (a Delaware limited liability company and wholly-owned subsidiary of Energy Transfer Equity, L.P.) and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Energy Transfer Partners, L.L.C. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2009, the four months ended December 31, 2007, and the year ended August 31, 2007 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2, the Company retrospectively adopted a new accounting pronouncement on January 1, 2009 related to the accounting for noncontrolling interests in consolidated financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
August 9, 2010

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 68,253	$ 91,962
Marketable securities	6,055	5,915
Accounts receivable, net of allowance for doubtful accounts	566,522	591,257
Accounts receivable from related companies	57,148	17,773
Inventories	389,954	272,348
Exchanges receivable	23,136	45,209
Price risk management assets	12,371	5,423
Other current assets	148,423	153,513
Total current assets	1,271,862	1,183,400
PROPERTY, PLANT AND EQUIPMENT, net	8,670,247	8,296,085
ADVANCES TO AND INVESTMENTS IN AFFILIATES	663,298	10,110
GOODWILL	775,093	773,282
INTANGIBLES AND OTHER ASSETS, net	384,109	394,399
Total assets	$ 11,764,609	$ 10,657,276

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

ENERGY TRANSFER PARTNERS, LLC AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

	December 31, 2009	December 31, 2008
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 358,997	$ 381,135
Accounts payable to related companies	38,842	34,551
Exchanges payable	19,203	54,636
Price risk management liabilities	442	94,978
Interest payable	136,229	106,265
Accrued and other current liabilities	228,946	433,794
Current maturities of long-term debt	40,923	45,232
Total current liabilities	823,582	1,150,591
LONG-TERM DEBT, less current maturities	6,177,046	5,618,715
DEFERRED INCOME TAXES	112,997	100,597
OTHER NON-CURRENT LIABILITIES	21,810	14,727
COMMITMENTS AND CONTINGENCIES (Note 10)		
	7,135,435	6,884,630
EQUITY:		
Member’s equity	18	16
Noncontrolling interest	4,629,156	3,772,630
Total equity	4,629,174	3,772,646
Total liabilities and equity	$ 11,764,609	$ 10,657,276

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

ENERGY TRANSFER PARTNERS, LLC AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
REVENUES:				
Natural gas operations	$4,115,806	$7,653,156	$1,832,192	$5,385,892
Retail propane	1,190,524	1,514,599	471,494	1,179,073
Other	110,965	126,113	45,824	227,072
Total revenues	5,417,295	9,293,868	2,349,510	6,792,037
COSTS AND EXPENSES:				
Cost of products sold - natural gas operations	2,519,575	5,885,982	1,343,237	4,207,700
Cost of products sold - retail propane	574,854	1,014,068	315,698	734,204
Cost of products sold - other	27,627	38,030	14,719	136,302
Operating expenses	680,893	781,831	221,757	559,600
Depreciation and amortization	312,803	262,151	71,333	179,162
Selling, general and administrative	173,954	194,227	59,167	145,516
Total costs and expenses	4,289,706	8,176,289	2,025,911	5,962,484
OPERATING INCOME	1,127,589	1,117,579	323,599	829,553
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(394,371)	(265,718)	(66,304)	(175,582)
Equity in earnings (losses) of affiliates	20,597	(165)	(94)	5,161
Gains (losses) on disposal of assets	(1,564)	(1,303)	14,310	(6,310)
Gains (losses) on non-hedged interest rate derivatives	39,239	(50,989)	(1,013)	31,032
Allowance for equity funds used during construction	10,557	63,976	7,276	4,948
Other, net	1,835	9,169	(5,198)	2,035
INCOME BEFORE INCOME TAX EXPENSE	803,882	872,549	272,576	690,837
Income tax expense	12,777	6,680	10,789	13,658
NET INCOME	791,105	865,869	261,787	677,179
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	791,069	865,837	261,778	677,155
NET INCOME ATTRIBUTABLE TO MEMBER	$ 36	$ 32	$ 9	$ 24

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)

	Year Ended December 31, 2009	Year Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Net income	$791,105	$865,869	$ 261,787	$ 677,179
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(10,211)	(34,901)	(17,269)	(160,420)
Change in value of derivative instruments accounted for as cash flow hedges	3,182	17,326	21,626	175,720
Change in value of available-for-sale securities	10,923	(6,418)	(98)	280
	3,894	(23,993)	4,259	15,580
Comprehensive income	794,999	841,876	266,046	692,759
Less: Comprehensive income attributable to noncontrolling interest	794,963	841,844	266,037	692,735
Comprehensive income attributable to member	$ 36	$ 32	$ 9	$ 24

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF EQUITY

(Dollars in thousands)

	Member's Equity	Noncontrolling Interest	Total
Balance, August 31, 2006	$ 11	$ 1,768,431	$1,768,442
Distributions to member	(21)	—	(21)
Distributions to noncontrolling interests	—	(612,405)	(612,405)
Subsidiary issuance of units	—	1,200,000	1,200,000
Tax effect of remedial income allocation from tax amortization of goodwill	—	(1,161)	(1,161)
Non-cash unit-based compensation expense	—	10,471	10,471
Other comprehensive income, net of tax	—	15,580	15,580
Other	—	(760)	(760)
Net income	24	677,155	677,179
Balance, August 31, 2007	14	3,057,311	3,057,325
Distributions to member	(6)	—	(6)
Distributions to noncontrolling interests	—	(172,390)	(172,390)
Subsidiary issuance of units	—	236,287	236,287
Tax effect of remedial income allocation from tax amortization of goodwill	—	(1,161)	(1,161)
Non-cash executive compensation	—	1,167	1,167
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	7,950	7,950
Other comprehensive income, net of tax	—	4,259	4,259
Sale of noncontrolling interest and other	—	(2,239)	(2,239)
Net income	9	261,778	261,787
Balance, December 31, 2007	17	3,392,962	3,392,979
Distributions to member	(33)	—	(33)
Distributions to noncontrolling interests	—	(855,273)	(855,273)
Subsidiary issuance of units	—	375,287	375,287
Tax effect of remedial income allocation from tax amortization of goodwill	—	(3,407)	(3,407)
Non-cash executive compensation	—	1,250	1,250
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	19,967	19,967
Other comprehensive income, net of tax	—	(23,993)	(23,993)
Net income	32	865,837	865,869
Balance, December 31, 2008	16	3,772,630	3,772,646
Distributions to member	(34)	—	(34)
Distributions to noncontrolling interests	—	(956,214)	(956,214)
Subsidiary issuance of units	—	999,676	999,676
Tax effect of remedial income allocation from tax amortization of goodwill	—	(3,762)	(3,762)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	20,613	20,613
Non-cash executive compensation	—	1,250	1,250
Other comprehensive income, net of tax	—	3,894	3,894
Net income	36	791,069	791,105
Balance, December 31, 2009	$ 18	$ 4,629,156	$4,629,174

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net income	$ 791,105	$ 865,869	$ 261,787	$ 677,179
Reconciliation of net income to net cash provided by operating activities:				
Depreciation and amortization	312,803	262,151	71,333	179,162
Amortization of finance costs charged to interest	8,645	5,886	1,435	4,061
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Goodwill impairment	—	11,359	—	—
Non-cash unit-based compensation expense	24,032	23,481	8,114	10,471
Non-cash executive compensation expense	1,250	1,250	442	—
Deferred income taxes	11,966	(5,280)	1,003	(4,042)
(Gains) losses on disposal of assets	1,564	1,303	(14,310)	6,310
Distributions in excess of (less than) equity in earnings of affiliates, net	3,224	5,621	4,448	(5,161)
Other non-cash	(4,468)	3,382	(2,069)	(761)
Net change in operating assets and liabilities, net of effects of acquisitions	(323,844)	59,207	(90,574)	255,697
Net cash provided by operating activities	829,269	1,242,244	242,153	1,127,145
CASH FLOWS FROM INVESTING ACTIVITIES:				
Net cash (paid for) received in acquisitions	30,367	(84,783)	(337,092)	(90,695)
Capital expenditures	(748,621)	(2,054,806)	(651,228)	(1,107,127)
Contributions in aid of construction costs	6,453	50,050	3,493	10,463
(Advances to) repayments from affiliates, net	(655,500)	54,534	(32,594)	(993,866)
Proceeds from the sale of assets	21,545	19,420	21,478	23,135
Net cash used in investing activities	(1,345,756)	(2,015,585)	(995,943)	(2,158,090)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from borrowings	3,475,107	6,015,461	1,741,547	4,757,971
Principal payments on debt	(2,954,771)	(4,699,154)	(1,062,272)	(4,260,523)
Subsidiary equity offerings, net of issue costs	936,337	373,059	234,887	1,200,000
Distributions to member	(34)	(33)	(6)	(21)
Distributions to noncontrolling interests	(956,214)	(855,273)	(172,390)	(612,405)
Debt issuance costs	(7,647)	(25,272)	(211)	(11,397)
Net cash provided by financing activities	492,778	808,788	741,555	1,073,625
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(23,709)	35,447	(12,235)	42,680
CASH AND CASH EQUIVALENTS, beginning of period	91,962	56,515	68,750	26,070
CASH AND CASH EQUIVALENTS, end of period	$ 68,253	$ 91,962	$ 56,515	$ 68,750

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

1. OPERATIONS AND ORGANIZATION:

Energy Transfer Partners, L.L.C. ("ETP LLC" or "the Company"), a Delaware limited liability company, is the General Partner of Energy Transfer Partners GP, L.P. ("ETP GP"), a Delaware limited partnership formed in August 2000, with a 0.01% general partner interest. ETP GP is the General Partner and owns the general partner interests of Energy Transfer Partners, L.P., a publicly-traded master limited partnership ("ETP").

Energy Transfer Equity, L.P. ("ETE") is the 100% owner of ETP LLC and also owns 100% of ETP GP.

Financial Statement Presentation

The consolidated financial statements of ETP LLC and subsidiaries presented herein for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). We consolidate all majority-owned and controlled subsidiaries. We present equity and net income attributable to noncontrolling interest for all partially-owned consolidated subsidiaries. All significant intercompany transactions and accounts are eliminated in consolidation. Management has evaluated subsequent events through August 9, 2010, the date the financial statements were available to be issued.

The consolidated financial statements of the Company presented herein include our controlled subsidiary, ETP, and its wholly-owned subsidiaries: La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company ("ETC OLP"); Energy Transfer Interstate Holdings, LLC ("ET Interstate"), the parent company of Transwestern Pipeline Company, LLC ("Transwestern") and ETC Midcontinent Express Pipeline, LLC ("ETC MEP"); ETC Fayetteville Express Pipeline, LLC ("ETC FEP"); ETC Tiger Pipeline, LLC ("ETC Tiger"); Heritage Operating, L.P. ("HOLP"); Heritage Holdings, Inc. ("HHI"); and Titan Energy Partners, L.P. ("Titan"). The operations of ET Interstate are included since the date of the Transwestern acquisition on December 1, 2006. ETC FEP and ETC Tiger are included since their inception dates on August 27, 2008 and June 20, 2008, respectively. The operations of all other subsidiaries listed above are reflected for all periods presented.

We also own varying undivided interests in certain pipelines. Ownership of these pipelines has been structured as an ownership of an undivided interest in assets, not as an ownership interest in a partnership, limited liability company, joint venture or other forms of entities. Each owner controls marketing and invoices separately, and each owner is responsible for any loss, damage or injury that may occur to their own customers. As a result, we apply proportionate consolidation for our interests in these entities.

In November 2007, we changed our fiscal year end to the calendar year. Thus, a new fiscal year began on January 1, 2008. The Company completed a four-month transition period that began September 1, 2007 and ended December 31, 2007. The financial statements contained herein cover the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the year ended August 31, 2007.

We did not recast the financial data for the prior fiscal periods because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the years ended December 31, 2009 and 2008 are substantially similar to what is reflected in the information for the year ended August 31, 2007.

Certain prior period amounts have been reclassified to conform to the 2009 presentation. Other than the reclassifications related to the adoption of Statement of Financial Accounting Standards No. 160, *Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51*, which is now incorporated into ASC 810-10-65 (see Note 2), these reclassifications had no impact on net income or total equity.

Business Operations

In order to simplify the obligations of ETP under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the “Operating Companies”) as follows:

- ETC OLP, a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, Arizona, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- ET Interstate, the parent company of Transwestern and ETC MEP, both of which are Delaware limited liability companies engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC Fayetteville Express Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC, a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- HOLP, a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan, a Delaware limited partnership also engaged in retail propane operations.

The Company, ETP GP, ETP, the Operating Companies and their subsidiaries are collectively referred to in this report as “we,” “us,” “our,” “ETP LLC” or the “Company.”

ETC OLP owns an interest in and operates approximately 14,800 miles of in service natural gas gathering and intrastate transportation pipelines, three natural gas processing plants, eleven natural gas treating facilities, eleven natural gas conditioning facilities and three natural gas storage facilities located in Texas.

Revenue in our intrastate transportation and storage operations is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The intrastate transportation and storage operations also consist of the HPL System, which generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System also transports natural gas for a variety of third party customers. Our intrastate transportation and storage operations also generate revenues from fees charged for storing customers’ working natural gas in our storage facilities. In addition, the use of the Bammel storage facility allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin.

Our interstate transportation operations principally focus on natural gas transportation of Transwestern, which owns and operates approximately 2,700 miles of interstate natural gas pipeline, with an additional 180 miles under construction, extending from Texas through the San Juan Basin to the California border. In addition, we have interests in joint ventures that have 500 miles of interstate natural gas pipeline and 185 miles under construction. Transwestern is a major natural gas transporter to the California border and delivers natural gas from the east end of its system to Texas intrastate and Midwest markets. The Transwestern pipeline interconnects with our existing intrastate pipelines in West Texas. The revenues of our interstate transportation operations consist primarily of fees earned from natural gas transportation services and operational gas sales.

Revenue in our midstream operations is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines (excluding the interstate transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

Our retail propane operations sell propane and propane-related products and services. The HOLP and Titan customer base includes residential, commercial, industrial and agricultural customers.

Recent Developments

MEP Transaction

On May 26, 2010, ETP completed the transfer of its membership interests in ETC Midcontinent Express Pipeline III, L.L.C. (“ETC MEP III”) to ETE (the “MEP Transaction”). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC (“MEP”), a joint venture with Kinder Morgan Energy Partners, L.P. (“KMP”) that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, ETP redeemed 12,273,830 ETP common units that were previously owned by ETE. ETP also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. This closing adjustment is subject to change during a final review period as defined in the contribution agreement. ETP also granted ETE an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. (“ETC MEP II”). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of its interest in ETC MEP III, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of its interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP (“Regency”) in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc. (“GE EFS”).

ETP continues to guarantee 50% of MEP’s obligations under MEP’s $175.4 million senior revolving credit facility, with the remaining 50% of MEP’s obligations guaranteed by KMP; however, Regency has agreed to indemnify ETP for any costs related to the guaranty of payments under this facility.

Other Acquisition

In January 2010, ETP purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, ETP recorded customer contracts of $68.2 million and goodwill of $27.3 million.

2. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND BALANCE SHEET DETAIL:

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the operating results estimated for the year ended December 31, 2009 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Revenue Recognition

Revenues for sales of natural gas, NGLs including propane, and propane appliances, parts, and fittings are recognized at the later of the time of delivery of the product to the customer or the time of sale or installation. Revenues from service labor, transportation, treating, compression and gas processing, are recognized upon completion of the service. Transportation capacity payments are recognized when earned in the period the capacity is made available. Tank rent is recognized ratably over the period it is earned.

ETP's intrastate transportation and storage and interstate transportation operations' results are determined primarily by the amount of capacity our customers reserve as well as the actual volume of natural gas that flows through the transportation pipelines. Under transportation contracts, our customers are charged (i) a demand fee, which is a fixed fee for the reservation of an agreed amount of capacity on the transportation pipeline for a specified period of time and which obligates the customer to pay even if the customer does not transport natural gas on the respective pipeline, (ii) a transportation fee, which is based on the actual throughput of natural gas by the customer, (iii) a fuel retention based on a percentage of gas transported on the pipeline, or (iv) a combination of the three, generally payable monthly.

ETP's intrastate transportation and storage operations also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies on the HPL System. Generally, we purchase natural gas from the market, including purchases from midstream's marketing operations, and from producers at the wellhead.

In addition, ETP's intrastate transportation and storage operations generate revenues and margin from fees charged for storing customers' working natural gas in our storage facilities. We also engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time utilizing the Bammel storage reservoir. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin. We expect margins from natural gas storage transactions to be higher during the periods from November to March of each year and lower during the period from April through October of each year due to the increased demand for natural gas during colder weather. However, we cannot assure that management's expectations will be fully realized in the future and in what time period, due to various factors including weather, availability of natural gas in regions in which we operate, competitive factors in the energy industry, and other issues.

Results from ETP's midstream operations are determined primarily by the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipeline and gathering systems and the level of natural gas and NGL prices. We generate midstream revenues and gross margins principally under fee-based or other arrangements in which we receive a fee for natural gas gathering, compressing, treating or processing services. The revenue earned from these arrangements is directly related to the volume of natural gas that flows through our systems and is not directly dependent on commodity prices.

We also utilize other types of arrangements in ETP's midstream operations, including (i) discount-to-index price arrangements, which involve purchases of natural gas at either (1) a percentage discount to a specified index price, (2) a specified index price less a fixed amount or (3) a percentage discount to a specified index price less an additional fixed amount, (ii) percentage-of-proceeds arrangements under which we gather and process natural gas on behalf of producers, sell the resulting residue gas and NGL volumes at market prices and remit to producers an agreed upon percentage of the proceeds based on an index price, and (iii) keep-whole arrangements where we gather natural gas from the producer, process the natural gas and sell the resulting NGLs to third parties at market prices. In many cases, we provide services under contracts that contain a combination of more than one of the arrangements described above. The terms of our contracts vary based on gas quality conditions, the competitive environment at the time the contracts are signed and customer requirements. Our contract mix may change as a result of changes in producer preferences, expansion in regions where some types of contracts are more common and other market factors.

ETP conducts marketing activities in which we market the natural gas that flows through our assets, referred to as on-system gas. We also attract other customers by marketing volumes of natural gas that do not move through our assets, referred to as off-system gas. For both on-system and off-system gas, we purchase natural gas from natural gas producers and other supply points and sell that natural gas to utilities, industrial consumers, other marketers and pipeline companies, thereby generating gross margins based upon the difference between the purchase and resale prices.

ETP has a risk management policy that provides for oversight over our marketing activities. These activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. As a result of our use of derivative financial instruments that may not qualify for hedge accounting, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to senior management and predefined limits and authorizations set forth in our risk management policy.

Regulatory Accounting - Regulatory Assets and Liabilities

Transwestern, part of our interstate transportation operations, is subject to regulation by certain state and federal authorities and has accounting policies that conform to Statement of Financial Accounting Standards No. 71 (As Amended), *Accounting for the Effects of Certain Types of Regulation*, now incorporated into ASC 980, which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

Cash, Cash Equivalents and Supplemental Cash Flow Information

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and which are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

As a result of our acquisition of a natural gas compression equipment business in exchange for ETP Common Units, cash acquired in connection with acquisitions during 2009 exceeded the cash we paid by $30.4 million.

The net change in operating assets and liabilities (net of acquisitions) included in cash flows from operating activities is comprised as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Accounts receivable	$ 28,431	$ 220,635	$ (169,263)	$ 54,347
Accounts receivable from related companies	(28,944)	1,858	(12,521)	(5,908)
Inventories	(101,592)	96,145	(168,430)	196,173
Exchanges receivable	22,074	(7,888)	(4,216)	(3,406)
Other current assets	8,167	(57,052)	(4,702)	53,598
Intangibles and other assets	(4,786)	(40,752)	605	(1,817)
Accounts payable	(16,024)	(296,185)	195,644	(92,172)
Accounts payable to related companies	4,455	(24,751)	25,459	32,936
Exchanges payable	(35,433)	14,254	6,117	3,000
Accrued and other current liabilities	(123,363)	32,377	976	(27,461)
Interest payable	29,963	42,951	33,415	14,844
Other long-term liabilities	1,401	1,741	(680)	1,460
Price risk management liabilities, net	(108,193)	75,874	7,022	30,103
Net change in assets and liabilities, net of effect of acquisitions	$(323,844)	$ 59,207	$ (90,574)	$255,697

Non-cash investing and financing activities and supplemental cash flow information are as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NON-CASH INVESTING ACTIVITIES:				
Transfer of investment in affiliate in purchase of Transwestern (Note 3)	$ —	$ —	$ —	$956,348
Investment in Calpine Corporation received in exchange for accounts receivable	$ —	$ 10,816	$ —	$ —
Capital expenditures accrued	$ 46,134	$ 153,230	$ 87,622	$ 43,498
NON-CASH FINANCING ACTIVITIES:				
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 26,237	$ 5,077	$ 3,896	$533,625
Subsidiary issuance of common units in connection with certain acquisitions	$ 63,339	$ 2,228	$ 1,400	$ —
SUPPLEMENTAL CASH FLOW INFORMATION:				
Cash paid for interest, net of interest capitalized	$ 367,924	$ 237,620	$ 51,465	$184,993
Cash paid for income taxes	$ 15,447	$ 4,674	$ 9,009	$ 8,583

Marketable Securities

Marketable securities are classified as available-for-sale securities and are reflected as current assets on the consolidated balance sheets at fair value.

During the year ended December 31, 2008, we determined there was an other-than-temporary decline in the market value of one of our available-for-sale securities, and reclassified into earnings a loss of $1.4 million, which is recorded in other expense. Unrealized holding gains (losses), net of tax, of $7.4 million, $(6.4) million, $(0.1) million, and $0.3 million were recorded through accumulated other comprehensive income ("AOCI"), based on the market value of the securities, for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively. The change in value of our available-for-sale securities for the year ended December 31, 2009 includes realized losses of $3.5 million reclassified from AOCI during the period as discussed in "Accounts Receivable" below.

Accounts Receivable

ETC OLP deals with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other form of security (corporate guaranty prepayment or master setoff agreement). Management reviews midstream and intrastate transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and intrastate transportation and storage operations. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. Management believes that the occurrence of bad debt in our midstream and intrastate transportation and storage operations was not significant at December 31, 2009 or 2008; therefore, an allowance for doubtful accounts for the midstream and intrastate transportation and storage operations was not deemed necessary.

ETP's interstate transportation operations have a concentration of customers in the electric and gas utility industries as well as natural gas producers. This concentration of customers may impact our overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral. Transwestern's management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Transwestern establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. Transwestern considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectability.

ETP propane operations grant credit to their customers for the purchase of propane and propane-related products. Included in accounts receivable are trade accounts receivable arising from HOLP's retail and wholesale propane and Titan's retail propane operations and receivables arising from liquids marketing activities. Accounts receivable for retail and wholesale propane operations are recorded as amounts are billed to customers less an allowance for doubtful accounts. The allowance for doubtful accounts for the propane operations is based on management's assessment of the realizability of customer accounts, based on the overall creditworthiness of our customers and any specific disputes.

ETP enters into netting arrangements with counterparties of derivative contracts to mitigate credit risk. Transactions are confirmed with the counterparty and the net amount is settled when due. Amounts outstanding under these netting arrangements are presented on a net basis in the consolidated balance sheets.

ETP exchanged a portion of its outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation ("Calpine") common stock valued at $10.8 million during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock is included in marketable securities on the consolidated balance sheet at a fair value of $4.8 million as of December 31, 2008. In 2009, ETP sold the stock for $7.3 million and recorded a realized loss of $3.6 million, of which $3.5 million was reclassified from AOCI to other income in the consolidated statement of operations.

Accounts receivable consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas operations	$ 429,849	$ 444,816
Propane	143,011	155,191
Less - allowance for doubtful accounts	(6,338)	(8,750)
Total, net	$ 566,522	$ 591,257

The activity in the allowance for doubtful accounts consisted of the following:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Balance, beginning of period	$ 8,750	$ 5,698	$ 5,601	$ 4,000
Accounts receivable written off, net of recoveries	(5,404)	(4,963)	(447)	(2,628)
Provision for loss on accounts receivable	2,992	8,015	544	4,229
Balance, end of period	$ 6,338	$ 8,750	$ 5,698	$ 5,601

Inventories

Inventories consist principally of natural gas held in storage valued at the lower of cost or market utilizing the weighted-average cost method. Propane inventories are also valued at the lower of cost or market utilizing the weighted-average cost of propane delivered to the customer service locations, including storage fees and inbound freight costs. The cost of appliances, parts and fittings is determined by the first-in, first-out method.

Inventories consisted of the following:

	December 31, 2009	December 31, 2008
Natural gas and NGLs, excluding propane	$ 157,103	$ 184,727
Propane	66,686	63,967
Appliances, parts and fittings and other	166,165	23,654
Total inventories	$ 389,954	$ 272,348

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. In April 2009, we began designating commodity derivatives as fair value hedges for accounting purposes. Subsequent to the designation of those fair value hedging relationships, changes in fair value of the designated hedged inventory have been recorded in inventory on our consolidated balance sheet and have been recorded in cost of products sold in our consolidated statements of operations.

During 2009, we recorded lower of cost or market adjustments of $54.0 million, which were offset by fair value adjustments related to our application of fair value hedging, of $66.1 million.

During 2008, we recorded lower-of-cost-or-market adjustments of $69.5 million for natural gas inventory and $4.4 million for propane inventory to reflect market values, which were less than the weighted-average cost. The natural gas inventory adjustment in 2008 was partially offset in net income by the recognition of unrealized gains on related cash flow hedges in the amount of $21.7 million from AOCI.

Exchanges

ETP’s midstream and intrastate transportation and storage operations’ exchanges consist of natural gas and NGL delivery imbalances with others. These amounts, which are valued at market prices, turn over monthly and are recorded as exchanges receivable or exchanges payable on our consolidated balance sheet. Management believes market value approximates cost.

ETP’s interstate transportation operations’ natural gas imbalances occur as a result of differences in volumes of gas received and delivered. Transwestern records natural gas imbalances for in-kind receivables and payables at the dollar weighted composite average of all current month gas transactions and dollar valued imbalances are recorded at contractual prices.

Other Current Assets

Other current assets consisted of the following:

	December 31, 2009	December 31, 2008
Deposits paid to vendors	$ 79,694	$ 78,237
Prepaid and other	68,729	75,276
Total other current assets	$ 148,423	$ 153,513

Property, Plant and Equipment

Property, plant and equipment are stated at cost less accumulated depreciation. Depreciation is computed using the straight-line method over the estimated useful or Federal Energy Regulatory Commission ("FERC") mandated lives of the assets. Expenditures for maintenance and repairs that do not add capacity or extend the useful life are expensed as incurred. Expenditures to refurbish assets that either extend the useful lives of the asset or prevent environmental contamination are capitalized and depreciated over the remaining useful life of the asset. Additionally, we capitalize certain costs directly related to the installation of company-owned propane tanks and construction of assets including internal labor costs, interest and engineering costs. Upon disposition or retirement of pipeline components or natural gas plant components, any gain or loss is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in our results of operations.

We review property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of long-lived assets is not recoverable, we reduce the carrying amount of such assets to fair value. No impairment of long-lived assets was required during the periods presented.

Capitalized interest is included for pipeline construction projects, except for interstate projects for which an allowance for funds used during construction ("AFUDC") is accrued. Interest is capitalized based on the current borrowing rate of ETP's revolving credit facility when the related costs are incurred. AFUDC is calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant for interstate projects. It represents the cost of servicing the capital invested in construction work-in-process. AFUDC is segregated into two component parts – borrowed funds and equity funds.

Components and useful lives of property, plant and equipment were as follows:

	December 31, 2009	December 31, 2008
Land and improvements	$ 87,224	$ 74,731
Buildings and improvements (10 to 40 years)	156,676	129,714
Pipelines and equipment (10 to 83 years)	6,933,189	5,136,357
Natural gas storage (40 years)	100,746	92,457
Bulk storage, equipment and facilities (3 to 83 years)	591,908	533,621
Tanks and other equipment (10 to 30 years)	602,915	578,118
Vehicles (3 to 10 years)	176,946	156,486
Right of way (20 to 83 years)	509,173	358,669
Furniture and fixtures (3 to 10 years)	32,810	28,075
Linepack	53,404	48,108
Pad gas	47,363	53,583
Other (5 to 10 years)	117,896	97,975
	9,410,250	7,287,894
Less – Accumulated depreciation	(979,158)	(700,826)
	8,431,092	6,587,068
Plus – Construction work-in-process	239,155	1,709,017
Property, plant and equipment, net	$8,670,247	$8,296,085

We recognized the following amounts of depreciation expense, capitalized interest, and AFUDC for the periods presented:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Depreciation expense	$ 291,908	$ 244,689	$ 64,569	$163,630
Capitalized interest, excluding AFUDC	$ 11,791	$ 21,595	$ 12,657	$ 22,979
AFUDC (both debt and equity components)	$ 10,237	$ 50,074	$ 5,095	$ 3,600

Advances to and Investment in Affiliates

We own interests in a number of related businesses that are accounted for using the equity method. In general, we use the equity method of accounting for an investment in which we have a 20% to 50% ownership and exercise significant influence over, but do not control the investee's operating and financial policies.

We account for our investments in Midcontinent Express Pipeline LLC and Fayetteville Express Pipeline LLC using the equity method. See Note 4 for a discussion of these joint ventures.

Goodwill

Goodwill is tested for impairment annually or more frequently if circumstances indicate that goodwill might be impaired. Our annual impairment test is performed as of December 31 for subsidiaries in our interstate operations and as of August 31 for all others. At December 31, 2008, we recorded an impairment of the entire goodwill balance of $11.4 million related to the Canyon Gathering System. No other goodwill impairments were recorded for the periods presented in these consolidated financial statements. Changes in the carrying amount of goodwill were as follows:

	Intrastate Transportation and Storage	Interstate Transportation	Midstream	Retail Propane	All Other	Total
Balance, December 31, 2007	$ 10,327	$ 98,613	$ 24,368	$594,801	$29,588	$757,697
Purchase accounting adjustments	—	—	—	2,457	—	2,457
Goodwill acquired	—	—	9,141	15,346	—	24,487
Goodwill Impairment	—	—	(11,359)	—	—	(11,359)
Balance, December 31, 2008	10,327	98,613	22,150	612,604	29,588	773,282
Purchase accounting adjustments	—	—	—	(8,662)	—	(8,662)
Goodwill acquired	—	—	—	33	10,440	10,473
Balance December 31, 2009	$ 10,327	$ 98,613	$ 22,150	$603,975	$40,028	$775,093

Goodwill is recorded at the acquisition date based on a preliminary purchase price allocation and generally may be adjusted when the purchase price allocation is finalized.

Intangibles and Other Assets

Intangibles and other assets are stated at cost, net of amortization computed on the straight-line method. We eliminate from our balance sheet the gross carrying amount and the related accumulated amortization for any fully amortized intangibles in the year they are fully amortized. Components and useful lives of intangibles and other assets were as follows:

	December 31, 2009		December 31, 2008	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (3 to 15 years)	$ 24,139	$ (12,415)	$ 40,301	$ (24,374)
Customer lists (3 to 30 years)	153,843	(53,123)	144,337	(39,730)
Contract rights (6 to 15 years)	23,015	(5,638)	23,015	(3,744)
Patents (9 years)	750	(35)	—	—
Other (10 years)	478	(397)	2,677	(2,244)
Total amortizable intangible assets	202,225	(71,608)	210,330	(70,092)
Non-amortizable intangible assets - Trademarks	75,825	—	75,667	—
Total intangible assets	278,050	(71,608)	285,997	(70,092)
Other assets:				
Financing costs (3 to 30 years)	68,597	(24,774)	59,108	(16,586)
Regulatory assets	101,879	(9,501)	98,560	(5,941)
Other	41,466	—	43,353	—
Total intangibles and assets	$489,992	$ (105,883)	$487,018	$ (92,619)

Aggregate amortization expense of intangible and other assets are as follows:

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Reported in depreciation and amortization	$ 20,895	$ 17,462	$ 6,764	$ 15,532
Reported in interest expense	$ 8,188	$ 6,008	$ 1,710	$ 4,502

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:		
2010	$	26,991
2011		25,326
2012		21,740
2013		16,310
2014		15,343

We review amortizable intangible assets for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of December 31 for our interstate operations and as of August 31 for all others. No impairment of intangible assets was required during the periods presented in these consolidated financial statements.

Asset Retirement Obligation

We record the fair value of an asset retirement obligation as a liability in the period a legal obligation for the retirement of tangible long-lived assets is incurred, typically at the time the assets are placed into service. A corresponding asset is also recorded and depreciated over the life of the asset. After the initial measurement, we also recognize changes in the amount of the liability resulting from the passage of time and revisions to either the timing or amount of estimated cash flows.

We have determined that we are obligated by contractual requirements to remove facilities or perform other remediation upon retirement of certain assets. Determination of the amounts to be recognized is based upon numerous estimates and assumptions, including expected settlement dates, future retirement costs, future inflation rates and the credit-adjusted risk-free interest rates. However, management was not able to reasonably measure the fair value of the asset retirement obligations as of December 31, 2009 or 2008 because the settlement dates were indeterminable. An asset retirement obligation will be recorded in the periods management can reasonably determine the settlement dates.

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	December 31, 2009	December 31, 2008
Customer advances and deposits	$ 88,430	$ 106,679
Accrued capital expenditures	46,134	153,230
Accrued wages and benefits	25,202	64,692
Taxes other than income taxes	23,294	20,772
Income taxes payable	3,401	14,538
Deferred income taxes	—	589
Other	42,485	73,294
Total accrued and other current liabilities	$ 228,946	$ 433,794

Customer Advances and Deposits

Deposits or advances are received from our customers as prepayments for natural gas deliveries in the following month and from our propane customers as security or prepayments for future propane deliveries. Prepayments and security deposits may also be required when customers exceed their credit limits or do not qualify for open credit.

Fair Value of Financial Instruments

The carrying amounts of accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at December 31, 2009 was $6.75 billion and $6.22 billion, respectively. At December 31, 2008, the aggregate fair value and carrying amount of long-term debt was $5.10 billion and $5.66 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (“OTC”) commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. We currently do not have any fair value measurements that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations.

The following table summarizes the fair value of our financial assets and liabilities as of December 31, 2009 and 2008 based on inputs used to derive their fair values:

	Fair Value Measurements at December 31, 2009 Using			Fair Value Measurements at December 31, 2008 Using		
Description	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets:						
Marketable securities	$ 6,055	$ 6,055	$ —	$ 5,915	$ 5,915	$ —
Natural gas inventories	156,156	156,156	—	—	—	—
Commodity derivatives	32,479	20,090	12,389	111,513	106,090	5,423
Liabilities:						
Commodity derivatives	(8,016)	(7,574)	(442)	(43,336)	—	(43,336)
Interest rate swap derivatives	—	—	—	(51,642)	—	(51,642)
	$186,674	$ 174,727	$ 11,947	$ 22,450	$ 112,005	$ (89,555)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated with pipeline construction and production well tie-ins. Contributions in aid of construction costs (“CIAC”) are netted against our project costs as they are received, and any CIAC which exceeds our total project costs, is recognized as other income in the period in which it is realized. In March 2008, we received a reimbursement related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million, which is recorded in other income on our consolidated statement of operations for the year ended December 31, 2008.

Contributions in aid of construction costs were as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Received and netted against project costs	$ 6,453	$ 50,050	$ 3,493	$ 10,463
Recorded in other income	(305)	8,352	216	403
Totals	$ 6,148	$ 58,402	$ 3,709	$ 10,866

Shipping and Handling Costs

Shipping and handling costs related to fuel sold are included in cost of products sold. Shipping and handling costs related to fuel consumed for compression and treating are included in operating expenses and totaled $55.9 million and $112.0 million for the years ended December 31, 2009 and 2008, respectively, $30.7 million for the four months ended December 31, 2007 and $58.6 million for the year ended August 31, 2007. We do not separately charge propane shipping and handling costs to customers.

Costs and Expenses

Costs of products sold include actual cost of fuel sold, adjusted for the effects of our hedging and other commodity derivative activities, storage fees and inbound freight on propane, and the cost of appliances, parts and fittings. Operating expenses include all costs incurred to provide products to customers, including compensation for operations personnel, insurance costs, vehicle maintenance, advertising costs, shipping and handling costs related to propane, purchasing costs and plant operations. Selling, general and administrative expenses include all ETP related expenses and compensation for executive, partnership, and administrative personnel.

We record the collection of taxes to be remitted to government authorities on a net basis.

Income Taxes

ETP LLC is a limited liability company. As a result, our earnings or losses, to the extent not included in a taxable subsidiary, for federal and state income tax purposes are included in the tax returns of the individual members. Net earnings for financial statement purposes may differ significantly from taxable income reportable to members as a result of differences between the tax basis and financial reporting basis of assets and liabilities.

ETP will be considered to have terminated for federal income tax purposes if the transfer of ETP units within a 12-month period constitute the sale or exchange of 50% or more of our capital and profits interests. In order to determine whether a sale or exchange of 50% or more of capital and profits interests has occurred, we review information available to us regarding transactions involving transfers of our units, including reported transfers of units by our affiliates and sales of units pursuant to trading activity in the public markets; however, the information we are able to obtain is generally not sufficient to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of ETP's capital and profits interests within the prior 12-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded.

ETP exceeded the 50% threshold on May 7, 2007, and, as a result, ETP terminated for federal tax income purposes on that date. This termination did not affect ETP's classification as a partnership for federal income tax purposes or otherwise affect the nature or extent of ETP's "qualifying income" for federal income tax purposes. This termination required ETP to close its taxable year, make new elections as to various tax matters and reset the depreciation schedule for its depreciable assets for federal income tax purposes. The resetting of its depreciation schedule resulted in a deferral of the depreciation deductions allowable in computing the taxable income allocated to ETP's Unitholders. However, certain elections made by ETP in connection with this tax termination allowed us to utilize deductions for the amortization of certain intangible assets for purposes of computing the taxable income allocable to certain of ETP's Unitholders, which deductions had not previously been utilized in computing taxable income allocable to ETP's Unitholders.

As a result of the tax termination discussed above, ETP elected new depreciation and amortization policies for income tax purposes, which include the amortization of goodwill. As a result of the income tax regulations related to remedial income allocations, our subsidiary, Heritage Holdings, Inc. ("HHI"), which owns ETP's Class E units, receives a special allocation of taxable income, for income tax purposes only, essentially equal to the amount of goodwill amortization deductions allocated to purchasers of ETP Common Units. The amount of such "goodwill" accumulated as of the date of ETP's acquisition of HHI (approximately $158.0 million) is now being amortized over 15 years beginning on May 7, 2007, the date of ETP's new tax elections. We account for the tax effects of the goodwill amortization and remedial income allocation as an adjustment of ETP's HHI purchase price allocation, which effectively results in a charge to our noncontrolling interest and a deferred tax benefit offsetting the current tax expense resulting from the remedial income allocation for tax purposes. For the years ended December 31, 2009 and 2008, the four months ended December, 31, 2007, and the year ended August 31, 2007, this resulted in a current tax expense and deferred tax benefit (with a corresponding charge to common equity as an adjustment of the purchase price allocation) of approximately $3.8 million, $3.4 million, $1.2 million and $1.2 million, respectively. As of December 31, 2009, the amount of tax goodwill to be amortized over the next 13 years for which HHI will receive a remedial income allocation is approximately $132.8 million.

We are treated as a disregarded entity for federal income tax purposes; therefore, certain income tax elections that ETE may make in the future could impact the amount of income tax expense that we recognize in future periods.

As a limited partnership, ETP is generally not subject to income tax. ETP is, however, subject to a statutory requirement that its non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of its total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of ETP's non-qualifying income exceeds this statutory limit, ETP would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries ("C corporations") of ETP. These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, ETP's non-qualifying income did not exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes, under which deferred income taxes are recorded based upon differences between the financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

Accounting for Derivative Instruments and Hedging Activities

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures and swaps and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our operations as follows:

- Derivatives are utilized in ETP's midstream operations in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.
- ETP uses derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. ETP also uses derivatives in our intrastate transportation and storage operations to hedge the sales price of retention gas and hedge location price differentials related to the transportation of natural gas.
- ETP's propane operations permit customers to guarantee the propane delivery price for the next heating season. As ETP executes fixed sales price contracts with our customers, ETP may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, ETP may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

For qualifying hedges, we formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment and the gains and losses offset related results on the hedged item in the statement of operations. The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in net income for the period.

If we designate a hedging relationship as a fair value hedge, we record the changes in fair value of the hedged asset or liability in cost of products sold in our consolidated statement of operations. This amount is offset by the changes in fair value of the related hedging instrument. Any ineffective portion or amount excluded from the assessment of hedge ineffectiveness is also included in the cost of products sold in the consolidated statement of operations.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using marked to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked in spread, either through mark-to-market or the physical withdrawal of natural gas.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

Cash flows from derivatives accounted for as cash flow hedges are reported as cash flows from operating activities, in the same category as the cash flows from the items being hedged.

If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in AOCI until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge’s change in fair value is recognized each period in earnings. Gains and losses deferred in AOCI related to cash flow hedges remain in AOCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For financial derivative instruments that do not qualify for hedge accounting, the change in fair value is recorded in cost of products sold in the consolidated statements of operations.

We are exposed to market risk for changes in interest rates related to our revolving credit facilities. We previously have managed a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements, which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not accounted for as cash flow hedges are classified in other income. See Note 11 for additional information related to interest rate derivatives

Allocation of Income (Loss)

For purposes of maintaining partner capital accounts, the Partnership Agreement specifies that items of income and loss shall generally be allocated among the partners in accordance with their percentage interests (see Note 6). Normal allocations according to percentage interests are made after giving effect to any priority income allocations in an amount equal to the incentive distributions that are allocated 100% to the General Partner.

Unit-Based Compensation

ETP accounts for equity awards issued to employees over the vesting period based on the grant-date fair value. The grant-date fair value is determined based on the market price of ETP's Common Units on the grant date, adjusted to reflect the present value of any expected distributions that will not accrue to the employee during the vesting period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected distributions based on the most recently declared distributions as of the grant date.

New Accounting Standards

Accounting Standards Codification. On July 1, 2009, the Financial Accounting Standards Board ("FASB") instituted a new referencing system, which codifies, but does not amend, previously existing nongovernmental GAAP. The *FASB Accounting Standards Codification*™ ("ASC") is now the single authoritative source for GAAP. Although the implementation of ASC has no impact on our financial statements, certain references to authoritative GAAP literature within our footnotes have been changed to cite the appropriate content within the ASC.

Noncontrolling Interests. On January 1, 2009, we adopted SFAS 160, now incorporated into ASC 810-10, which established new accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. Specifically, the new standard requires the recognition of a noncontrolling interest (minority interest) as equity in the consolidated financial statements and separate from the parent's equity. The amount of net income attributable to the noncontrolling interest is included in consolidated net income on the face of the income statement. The new standard clarifies that changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation are equity transactions if the parent retains its controlling financial interest. In addition, the new standard requires that a parent recognizes a gain or loss in net income when a subsidiary is deconsolidated. Such gain or loss is measured using the fair value of the noncontrolling equity investment on the deconsolidation date. This standard also includes expanded disclosure requirements regarding the interests of the parent and its noncontrolling interest. The adoption of this standard did not have a significant impact on our financial position or results of operations. However, it did result in certain changes to our financial statement presentation, including the change in classification of noncontrolling interest (minority interest) from liabilities to equity on the condensed consolidated balance sheet.

Upon adoption, we reclassified $3.77 billion from minority interest liability to noncontrolling interest as a separate component of equity on our consolidated balance sheet as of December 31, 2008. In addition, we reclassified $865.8 million, $261.8 million and $677.2 million of minority interest expense to net income attributable to noncontrolling interest in our consolidated statements of operations for the year ended December 31, 2008, the four month transition period ended December 31, 2007 and the year ended August 31, 2007.

Business Combinations. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 141 (Revised 2007), *Business Combinations*, which is now incorporated into ASC 805. The new standard significantly changes the accounting for business combinations and includes a substantial number of new disclosure requirements. The new standard requires an acquiring entity to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions and changes the accounting treatment for certain specific items, including:

- Acquisition costs are generally expensed as incurred;
- Noncontrolling interests (previously referred to as "minority interests") are valued at fair value at the acquisition date;
- In-process research and development is recorded at fair value as an indefinite-lived intangible asset at the acquisition date;
- Restructuring costs associated with a business combination are generally expensed subsequent to the acquisition date; and
- Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date are recorded in income taxes.

Our adoption of this standard did not have an immediate impact on our financial position or results of operations; however, it has impacted the accounting for our business combinations subsequent to adoption.

Derivative Instruments and Hedging Activities. On January 1, 2009, we adopted Statement of Financial Accounting Standards No. 161, *Disclosures about Derivative Instruments and Hedging Activities - An Amendment of FASB Statement No. 133*, which is now incorporated into ASC 815. This standard changed the disclosure requirements for derivative instruments and hedging activities, including requirements for qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. The standard only affected disclosure requirements; therefore, our adoption did not impact our financial position or results of operations.

Equity Method Investment Accounting. On January 1, 2009, we adopted Emerging Issues Task Force Issue No. 08-6, *Equity Method Investment Accounting Considerations*, which is now incorporated into ASC 323-10. This standard establishes the requirements for initial measurement of an equity method investment, including the accounting for contingent consideration related to the acquisition of an equity method investment, and also clarifies the accounting for (1) an other-than-temporary impairment of an equity method investment and (2) changes in level of ownership or degree of influence with respect to an equity method investment. Our adoption did not have a material impact on our financial position or results of operations.

Subsequent Events. During 2009, we adopted Statement of Financial Accounting Standards No. 165, *Disclosures about Subsequent Events*, which is now incorporated into ASC 855. Under this standard, we are required to evaluate subsequent events through the date that our financial statements are issued and also required to disclose the date through which subsequent events are evaluated. The adoption of this standard does not change our current practices with respect to evaluating, recording and disclosing subsequent events; therefore, our adoption of this statement during the second quarter had no impact on our financial position or results of operations.

3. ACQUISITIONS:

2010

In January 2010, ETP purchased a natural gas gathering company which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale. The purchase price is $150 million in cash, excluding certain adjustments as defined in the purchase agreement, and the acquisition closed in March 2010.

2009

In November 2009, we acquired all of the outstanding equity interests of a natural gas compression equipment business with operations in Arkansas, California, Colorado, Louisiana, New Mexico, Oklahoma, Pennsylvania and Texas, in exchange for our issuance of 1,450,076 Common Units having an aggregate market value of approximately $63.3 million on the closing date. In connection with this transaction, we received cash of $41.1 million, assumed total liabilities of $30.5 million, which includes $8.4 million in notes payable and recorded goodwill of $8.7 million. In addition, we acquired ETG in August 2009. See Note 13.

2008

During the year ended December 31, 2008, HOLP and Titan collectively acquired substantially all of the assets of 20 propane businesses. The aggregate purchase price for these acquisitions totaled $96.4 million, which included $76.2 million of cash paid, net of cash acquired, liabilities assumed of $8.2 million, 53,893 Common Units issued valued at $2.2 million and debt forgiveness of $9.8 million. The cash paid for acquisitions was financed primarily with ETP's and HOLP's Senior Revolving Credit Facilities. We recorded $15.3 million of goodwill in connection with these acquisitions.

Transition Period 2007

Canyon Acquisition

In October 2007, we acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the "Canyon acquisition") for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The purchase price was initially allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. We completed the purchase price allocation during the third quarter of 2008. The adjustments to the purchase price allocation were not material. The final allocations of the purchase price are noted below:

Accounts receivable	$ 3,613
Inventory	183
Prepaid and other current assets	1,606
Property, plant, and equipment	284,910
Intangibles and other assets	6,351
Goodwill	11,359
Total assets acquired	308,022
Accounts payable	(1,840)
Customer advances and deposits	(1,030)
Total liabilities assumed	(2,870)
Net assets acquired	$305,152

2007

On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services ("GE") and Southern Union Company ("Southern Union"), we acquired the member interests in CCE Holdings, LLC ("CCEH") from GE and certain other investors for $1.00 billion. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to ETE simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP's 50% ownership interest in CCEH in exchange for 100% ownership of Transwestern, which owns the Transwestern pipeline. Following the final step, Transwestern became a new operating subsidiary and formed our interstate transportation operations.

The total acquisition cost for Transwestern, net of cash acquired, was as follows:

Basis of investment in CCEH at November 30, 2006	$ 956,348
Distributions received on December 1, 2006	(6,217)
Fair value of short-term debt assumed	13,000
Fair value of long-term debt assumed	519,377
Other assumed long-term indebtedness	10,096
Current liabilities assumed	35,781
Cash acquired	(3,386)
Acquisition costs incurred	11,696
Total	$1,536,695

In September 2006, we acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of $30.6 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $25.0 million to be determined eighteen months from the closing date. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas and are included in our midstream operations. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility. In March 2008, a contingent payment of $8.7 million was recorded as an adjustment to goodwill in our midstream operations.

In December 2006, we purchased a natural gas gathering system in north Texas for $32.0 million in cash. The purchase and sale agreement for the gathering system in north Texas also had a contingent payment not to exceed $21.0 million to be determined two years after the closing date. In December 2008, it was determined that a contingency payment would not be required. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas. The cash paid for this acquisition was financed primarily from advances under the previously existing credit facility.

During the fiscal year ended August 31, 2007, HOLP and Titan collectively acquired substantially all of the assets of five propane businesses. The aggregate purchase price for these acquisitions totaled $17.6 million, which included $15.5 million of cash paid, net of cash acquired, and liabilities assumed of $2.1 million. The cash paid for acquisitions was financed primarily with ETP's and HOLP's Senior Revolving Credit Facilities.

Except for the acquisition of the 50% member interests in CCEH, our acquisitions were accounted for under the purchase method of accounting and the purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. The acquisition of 100% of Transwestern has been accounted for under the purchase method of accounting since the acquisition on December 1, 2006.

The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for the fiscal year 2007 acquisitions described above, net of cash acquired:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$ —	$ 20,062	$ 1,111
Inventory	—	895	414
Prepaid and other current assets	—	11,842	57
Investment in unconsolidated affiliate	(503)	—	—
Property, plant, and equipment	50,916	1,254,968	8,035
Intangibles and other assets	23,015	141,378	3,808
Goodwill	—	107,550	4,167
Total assets acquired	73,428	1,536,695	17,592
Accounts payable	—	(1,932)	(381)
Customer advances and deposits	—	(700)	(254)
Accrued and other current liabilities	(292)	(33,149)	(170)
Short-term debt (paid in December 2006)	—	(13,000)	—
Long-term debt	—	(519,377)	(1,309)
Other long-term obligations	—	(10,096)	—
Total liabilities assumed	(292)	(578,254)	(2,114)
Net assets acquired	$ 73,136	$ 958,441	$ 15,478

The purchase price for the acquisitions was initially allocated based on the estimated fair value of the assets acquired and liabilities assumed. The Transwestern allocation was based on the preliminary results of independent appraisals. The purchase price allocations were completed during the first quarter of 2008. The final allocation adjustments were not significant.

Included in the property, plant and equipment associated with the Transwestern acquisition is an aggregate plant acquisition adjustment of $446.2 million, which represents costs allocated to Transwestern's transmission plant. This amount has not been included in the determination of tariff rates Transwestern charges to its regulated customers. The unamortized balance of this adjustment was $419.6 million at December 31, 2008 and is being amortized over 35 years, the composite weighted average estimated remaining life of Transwestern's assets as of the acquisition date.

Regulatory assets, included in intangible and other assets on the consolidated balance sheet, established in the Transwestern purchase price allocation consist of the following:

Accumulated reserve adjustment	$ 42,132
AFUDC gross-up	9,280
Environmental reserves	6,623
South Georgia deferred tax receivable	2,593
Other	9,329
Total Regulatory Assets acquired	$ 69,957

All of Transwestern's regulatory assets are considered probable of recovery in rates.

We recorded the following intangible assets and goodwill in conjunction with the fiscal year 2007 acquisitions described above:

	Intrastate Transportation and Storage and Midstream Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Intangible assets:			
Contract rights and customer lists (6 to 15 years)	$ 23,015	$ 47,582	$ —
Financing costs (7 to 9 years)	—	13,410	—
Other	—	—	3,808
Total intangible assets	23,015	60,992	3,808
Goodwill	—	107,550	4,167
Total intangible assets and goodwill acquired	$ 23,015	$ 168,542	$ 7,975

Goodwill was warranted because these acquisitions enhance our current operations, and certain acquisitions are expected to reduce costs through synergies with existing operations. We expect all of the goodwill acquired to be tax deductible. We do not believe that the acquired intangible assets have any significant residual value at the end of their useful life.

4. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline LLC

ETP is party to an agreement with Kinder Morgan Energy Partners, L.P. ("KMP") for a 50/50 joint development of the Midcontinent Express pipeline. Construction of the approximately 500-mile pipeline was completed and natural gas transportation service commenced August 1, 2009 on the pipeline from Delhi, Louisiana, to an interconnect with the Transco interstate natural gas pipeline in Butler, Alabama. Interim service began on the pipeline from Bennington, Oklahoma, to Delhi in April 2009. In July 2008, Midcontinent Express Pipeline LLC ("MEP"), the entity formed to construct, own and operate this pipeline, completed an open season with respect to a capacity expansion of the pipeline from the current capacity of 1.4 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to an interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional capacity was fully subscribed as a result of this open season. The planned expansion of capacity will be added through the installation of additional compression on this segment of the pipeline and is expected to be completed in the latter part of 2010. This expansion was approved by the Federal Energy Regulatory Commission (the "FERC") in September 2009.

On January 9, 2009, MEP filed an amended application to revise its initial transportation rates to reflect an increase in projected costs for the project; the amended application was approved by the FERC on March 25, 2009.

On May 26, 2010, ETP transferred to ETE, in exchange for ETP common units owned by ETE, substantially all of its interest in MEP. In conjunction with this transfer, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of the interest to its estimated fair value. See discussion of the transaction in "Recent Developments" at Note 1.

Fayetteville Express Pipeline LLC

ETP is party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Quitman County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC ("FEP"), the entity formed to construct, own and operate this pipeline, received FERC approval of its application for authority to construct and operate this pipeline. That order is currently subject to a limited request for rehearing. The pipeline is expected to have an initial capacity of 2.0 Bcf/d. The pipeline project is expected to be in service by the end of 2010. FEP has secured binding 10-year commitments for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America ("NGPL") in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

Capital Contributions to Affiliates

During the year ended December 31, 2009, we contributed $664.5 million to MEP. FEP's capital expenditures are being funded under a credit facility. All of our contributions to FEP were reimbursed to us in 2009, including $9.0 million that we contributed in 2008.

Summarized Financial Information

The following tables present aggregated selected balance sheet and income statement data for our unconsolidated affiliates, MEP and FEP (on a 100% basis):

	December 31, 2009	December 31, 2008
Current assets	$ 33,794	$ 9,953
Property, plant and equipment, net	2,576,031	1,012,006
Other assets	19,658	—
Total assets	$2,629,483	$1,021,959
Current liabilities	$ 105,951	$ 163,379
Non-current liabilities	1,198,882	840,580
Equity	1,324,650	18,000
Total liabilities and equity	$2,629,483	$1,021,959

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Revenue	$ 98,593	$ —	$ —	$ —
Operating income	47,818	—	—	—
Net income	36,555	1,057	—	—

As stated above, MEP was placed into service during 2009.

5. **DEBT OBLIGATIONS:**

Our debt obligations consist of the following:

	December 31, 2009	December 31, 2008	
ETP Senior Notes:			
5.95% Senior Notes, due February 1, 2015	$ 750,000	$ 750,000	Payable upon maturity. Interest is paid semi-annually.
5.65% Senior Notes, due August 1, 2012	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.125% Senior Notes, due February 15, 2017	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.625% Senior Notes, due October 15, 2036	400,000	400,000	Payable upon maturity. Interest is paid semi-annually.
6.0% Senior Notes, due July 1, 2013	350,000	350,000	Payable upon maturity. Interest is paid semi-annually.
6.7% Senior Notes, due July 1, 2018	600,000	600,000	Payable upon maturity. Interest is paid semi-annually.
7.5% Senior Notes, due July 1, 2038	550,000	550,000	Payable upon maturity. Interest is paid semi-annually.
9.7% Senior Notes due March 15, 2019	600,000	600,000	Put option on March 15, 2012. Payable upon maturity. Interest is paid semi-annually.
8.5% Senior Notes due April 15, 2014	350,000	—	Payable upon maturity. Interest is paid semi-annually.
9.0% Senior Notes due April 15, 2019	650,000	—	Payable upon maturity. Interest is paid semi-annually.
Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Notes, due November 17, 2014	88,000	88,000	Payable upon maturity. Interest is paid semi-annually.
5.54% Senior Unsecured Notes, due November 17, 2016	125,000	125,000	Payable upon maturity. Interest is paid semi-annually.
5.64% Senior Unsecured Notes, due May 24, 2017	82,000	82,000	Payable upon maturity. Interest is paid semi-annually.
5.89% Senior Unsecured Notes, due May 24, 2022	150,000	150,000	Payable upon maturity. Interest is paid semi-annually.
6.16% Senior Unsecured Notes, due May 24, 2037	75,000	75,000	Payable upon maturity. Interest is paid semi-annually.
5.36% Senior Unsecured Notes, due December 9, 2020	175,000	—	Payable upon maturity. Interest is paid semi-annually.
5.66% Senior Unsecured Notes, due December 9, 2024	175,000	—	Payable upon maturity. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
8.55% Senior Secured Notes	24,000	36,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
Medium Term Note Program:			
7.17% Series A Senior Secured Notes	—	2,400	Matured in November 2009.
7.26% Series B Senior Secured Notes	6,000	8,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	4,571	9,142	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	5,750	11,500	Annual payments of $5,750 due August 15, 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	33,100	45,550	Annual payments of $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	6,000	7,000	Annual payments of $1,000 due each August 15 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.89% Series H Senior Secured Notes	5,091	5,818	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility	150,000	902,000	See terms below under "ETP Credit Facility".
HOLP Fourth Amended and Restated Senior Revolving Credit Facility	10,000	10,000	See terms below under "HOLP Credit Facility".
Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 8.06% and 7.91% for December 31, 2009 and 2008, respectively	7,898	11,249	Due in installments through 2014
Other	2,388	2,765	Due in installments through 2024.
Unamortized discounts	(12,829)	(13,477)	
	6,217,969	5,663,947	
Current maturities	(40,923)	(45,232)	
	$6,177,046	$5,618,715	

Future maturities of long-term debt for each of the next five years and thereafter are as follows:

2010	$ 40,923
2011	44,607
2012	572,881
2013	372,569
2014	443,519
Thereafter	4,743,470
	$6,217,969

ETP Senior Notes

The ETP Senior Notes were registered under the Securities Act of 1933 (as amended). ETP may redeem some or all of the ETP Senior Notes at any time, or from time to time, pursuant to the terms of the indenture and related indenture supplements related to the ETP Senior Notes. Interest on the ETP Senior Notes is paid semi-annually.

The ETP Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership's subsidiaries. As a result, the ETP Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

In April 2009, ETP completed a public offering of $350.0 million aggregate principal amount of 8.5% Senior Notes due 2014 and $650.0 million aggregate principal amount of 9.0% Senior Notes due 2019 (collectively the "2009 ETP Notes"). The offering of the 2009 ETP Notes closed on April 7, 2009 and ETP used net proceeds of approximately $993.6 million to repay borrowings under the ETP Credit Facility and for general partnership purposes. Interest will be paid semi-annually.

Transwestern Senior Unsecured Notes

Transwestern's long-term debt consists of $213.0 million remaining principal amount of notes assumed in connection with the Transwestern acquisition, $307.0 million aggregate principal amount of notes issued in May 2007, and $350.0 million aggregate principal amount of notes issued in December 2009. The proceeds from the notes issued in December 2009 were used by Transwestern to repay amounts under an intercompany loan agreement. No principal payments are required under any of the Transwestern notes prior to their respective maturity dates. The Transwestern notes rank pari passu with Transwestern's other unsecured debt. The Transwestern notes are payable at any time in whole or pro rata in part, subject to a premium or upon a change of control event or an event of default, as defined. Interest is paid semi-annually.

Transwestern's debt agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and specify a maximum debt to capitalization ratio.

HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the "HOLP Notes").

Revolving Credit Facilities

ETP Credit Facility

The ETP Credit Facility provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity, under the Amended and Restated Credit Agreement). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating and the fee is 0.11% based on our current rating with a maximum fee of 0.125%.

As of December 31, 2009, there was a balance outstanding in the ETP Credit Facility of $150.0 million in revolving credit loans and approximately $62.2 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2009 was 0.78%. The total amount available under the ETP Credit Facility, as of December 31, 2009, which is reduced by any letters of credit, was approximately $1.79 billion. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of ETP's subsidiaries and has equal rights to holders of our current and future unsecured debt. The indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility (total book value as of December 31, 2009 of approximately $1.2 billion). At December 31, 2009, there was $10.0 million outstanding in revolving credit loans and outstanding letters of credit of $1.0 million. The amount available for borrowing as of December 31, 2009 was $64.0 million.

Covenants Related to Our Credit Agreements

The agreements related to the ETP Senior Notes contain restrictive covenants customary for an issuer with an investment-grade rating from the rating agencies, which covenants include limitations on liens and a restriction on sale-leaseback transactions. The agreements and indentures related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to ETP and the Operating Companies, including the maintenance of various financial and leverage covenants, limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens as described in further detail below.

The credit agreement relating to the ETP Credit Facility contains covenants that limit (subject to certain exceptions) ETP's and certain of ETP's subsidiaries, ability to, among other things:

- incur indebtedness;
- grant liens;
- enter into mergers;
- dispose of assets;
- make certain investments;
- make Distributions (as defined in such credit agreement) during certain Defaults (as defined in such credit agreement) and during any Event of Default (as defined in such credit agreement);
- engage in business substantially different in nature than the business currently conducted by ETP and its subsidiaries;
- engage in transactions with affiliates;
- enter into restrictive agreements; and
- enter into speculative hedging contracts.

The credit agreement related to the ETP Credit Facility also contains a financial covenant that provides that on each date we make a distribution, the leverage ratio, as defined in the ETP Credit Facility, shall not exceed 5.0 to 1, with a permitted increase to 5.5 to 1 during a specified acquisition period, as defined in the ETP Credit Facility. This financial covenant could therefore restrict our ability to make cash distributions to our Unitholders, our general partner and the holder of our incentive distribution rights.

The agreements related to the HOLP Notes and the HOLP Credit Facility contain customary restrictive covenants applicable to HOLP, including the maintenance of various financial and leverage covenants and limitations on substantial disposition of assets, changes in ownership, the level of additional indebtedness and creation of liens. The financial covenants require HOLP to maintain ratios of Adjusted Consolidated Funded Indebtedness to Adjusted Consolidated EBITDA (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not more than 4.75 to 1 and Consolidated EBITDA to Consolidated Interest Expense (as these terms are similarly defined in the agreements related to the HOLP Notes and HOLP Credit Facility) of not less than 2.25 to 1. These debt agreements also provide that HOLP may declare, make, or incur a liability to make restricted payments during each fiscal quarter, if: (a) the amount of such restricted payment, together with all other restricted payments during such quarter, do not exceed the amount of Available Cash (as defined in the agreements related to the HOLP Notes and HOLP Credit Facility) with respect to the immediately preceding quarter (which amount is required to reflect a reserve equal to 50% of the interest to be paid on the HOLP Notes during the last quarter and in addition, in the third, second and first quarters preceding a quarter in which a scheduled principal payment is to be made on the HOLP Notes, and a reserve equal to 25%, 50%, and 75%, respectively, of the principal amount to be repaid on such payment dates), (b) no default or event of default exists before such restricted payments, and (c) the amounts of HOLP's restricted payment is not disproportionately greater than the payment amount from ETC OLP utilized to fund payment obligations of ETP and its general partner with respect to ETP's Common Units.

Failure to comply with the various restrictive and affirmative covenants of our revolving credit facilities and the note agreements related to the HOLP Notes could require us to pay debt balances prior to scheduled maturity and could negatively impact the Operating Companies' ability to incur additional debt and/or our ability to pay distributions.

We are required to assess compliance quarterly and we were in compliance with all requirements, limitations, and covenants related to our debt agreements as of December 31, 2009.

6. MEMBER'S EQUITY:

The ETP LLC membership agreement contains specific provisions for the allocation of net earnings and losses to members for purposes of maintaining the partner capital accounts. The Board of the Company may distribute to the Member funds of the Company, which the Board reasonably determines are not needed for the payment of existing or foreseeable company obligations and expenditures.

Sale of Common Units by ETP

In January 2010, ETP issued 9,775,000 ETP Common Units through a public offering. The proceeds of $423.6 million from the offering were used primarily to repay borrowings under ETP's revolving credit facility and to fund capital expenditures related to pipeline projects.

On August 26, 2009, ETP entered into an Equity Distribution Agreement with UBS Securities LLC ("UBS"). Pursuant to this agreement, ETP may offer and sell from time to time through UBS, as their sales agent, ETP Common Units having an aggregate value of up to $300.0 million. Sales of the units will be made by means of ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed between ETP and UBS. Under the terms of this agreement, ETP may also sell ETP Common Units to UBS as principal for its own account at a price agreed upon at the time of sale. Any sale of ETP Common Units to UBS as principal would be pursuant to the terms of a separate agreement between ETP and UBS. During the six months ended June 30, 2010, ETP issued 3,340,783 ETP Common Units pursuant to this agreement. The proceeds of approximately $151.0 million, net of commissions, were used for general partnership purposes. In addition, ETP initiated trades on an additional 501,500 ETP Common Units that had not settled as of June 30, 2010. Approximately $40.6 million of ETP's Common Units remain available to be issued under the agreement based on trades initiated through June 30, 2010.

Contributions to Subsidiary

In order to maintain our general partner interest in ETP, ETP GP has previously been required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP. ETP GP was required to contribute approximately $12.3 million and $8.0 million for the years ended December 31, 2009 and 2008, $5.0 million for the four months ended December 31, 2007, and $24.5 million for the year ended August 31, 2007, respectively. As of December 31, 2009, ETP GP has a contribution payable to ETP of $8.9 million.

In July 2009, ETP amended and restated its partnership agreement, and as a result, ETP GP is no longer required to make corresponding contributions to maintain its general partner interest in ETP.

ETP's Quarterly Distribution of Available Cash

ETP's Partnership Agreement requires that ETP distribute all of its Available Cash to its Unitholders and its General Partner within 45 days following the end of each fiscal quarter, subject to the payment of incentive distributions to the holders of IDRs to the extent that certain target levels of cash distributions are achieved. The term Available Cash generally means, with respect to any fiscal quarter of ETP, all cash on hand at the end of such quarter, plus working capital borrowings after the end of the quarter, less reserves established by its General Partner in its sole discretion to provide for the proper conduct of ETP's business, to comply with applicable laws or any debt instrument or other agreement, or to provide funds for future distributions to partners with respect to any one or more of the next four quarters. Available Cash is more fully defined in ETP's Partnership Agreement.

ETP GP has the right, in connection with the issuance of any equity security by ETP, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in ETP as ETP GP and its affiliates owned immediately prior to such issuance.

ETP's distributions declared during the periods presented below are summarized as follows:

	Record Date	Payment Date	Amount per Unit
Calendar Year Ended December 31, 2009	November 9, 2009	November 16, 2009	$ 0.89375
	August 7, 2009	August 14, 2009	0.89375
	May 8, 2009	May 15, 2009	0.89375
	February 6, 2009	February 13, 2009	0.89375
Calendar Year Ended December 31, 2008	November 10, 2008	November 14, 2008	$ 0.89375
	August 7, 2008	August 14, 2008	0.89375
	May 5, 2008	May 15, 2008	0.86875
	February 1, 2008 (1)	February 14, 2008	1.12500
Transition Period Ended December 31, 2007	October 5, 2007	October 15, 2007	$ 0.82500
Fiscal Year Ended August 31, 2007	July 2, 2007	July 16, 2007	$ 0.80625
	April 6, 2007	April 13, 2007	0.78750
	January 4, 2007	January 15, 2007	0.76875
	October 5, 2006	October 16, 2006	0.75000

(1) One-time four month distribution – On January 18, 2008 ETP's Board of Directors approved the management recommendation for a one-time four-month distribution for ETP Unitholders to complete the conversion to a calendar year end from the previous August 31 fiscal year end. ETP's distribution amount related to the four months ended December 31, 2007 was $1.125 per Common Unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This distribution was paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

The total amount of distributions ETP GP received from ETP relating to its general partner interests and incentive distribution rights of ETP are as follows (shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
General Partner interest	$ 19,505	$ 17,322	$ 5,110	$ 13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$ 369,991	$ 315,897	$ 90,885	$236,058

The total amounts of ETP distributions declared during the periods presented in the consolidated financial statements are as follows (all from Available Cash from ETP's operating surplus and are shown in the period to which they relate):

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Limited Partners -				
Common Units	$ 629,263	$537,731	$ 160,672	$396,095
Class E Units	12,484	12,484	3,121	12,484
Class G Units	—	—	—	40,598
General Partner interest	19,505	17,322	5,110	13,705
Incentive Distribution Rights	350,486	298,575	85,775	222,353
	$1,011,738	$866,112	$ 254,678	$685,235

Upon their conversion to ETP Common Units, all the ETP Class G Units ceased to have the right to participate in ETP distributions of available cash from operating surplus as itemized above.

Distributions paid by ETP subsequent to December 31, 2009 are summarized as follows:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2009	February 8, 2010	February 15, 2010	$ 0.89375
March 31, 2010	May 7, 2010	May 17, 2010	0.89375

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at the close of business on August 9, 2010.

7. UNIT-BASED COMPENSATION PLANS OF ETP:

ETP has issued equity awards to employees and directors under the following plans:

- ***2008 Long-Term Incentive Plan***. On December 16, 2008, ETP Unitholders approved the ETP 2008 Long-Term Incentive Plan (the "2008 Incentive Plan"), which provides for awards of options to purchase ETP Common Units, awards of restricted units, awards of phantom units, awards of Common Units, awards of distribution equivalent rights ("DERs"), awards of Common Unit appreciation rights, and other unit-based awards to employees of ETP, ETP GP, ETP LLC, a subsidiary or their affiliates, and members of ETP LLC's board of directors, which we refer to as our board of directors. Up to 5,000,000 ETP Common Units may be granted as awards under the 2008 Incentive Plan, with such amount subject to adjustment as provided for under the terms of the 2008 Incentive Plan. The 2008 Incentive Plan is effective until December 16, 2018 or, if earlier, the time which all available units under the 2008 Incentive Plan have been issued to participants or the time of termination of the plan by our board of directors. As of December 31, 2009, a total of 4,213,111 ETP Common Units remain available to be awarded under the 2008 Incentive Plan.

- ***2004 Unit Plan***. ETP's Amended and Restated 2004 Unit Award Plan (the "2004 Unit Plan") provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers and directors. Any awards that are forfeited, or which expire for any reason or any units, which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. As of December 31, 2009, 5,578 ETP Common Units were available for future grants under the 2004 Unit Plan.

ETP Employee Grants

Prior to December 2007, substantially all of the awards granted to employees required the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three-year period with 100% of such one-third vesting if the total return for the ETP units for such year is in the top quartile as compared to a peer group of energy-related publicly traded limited partnerships determined by the Compensation Committee, 65% of such one-third vesting if the total return of the ETP units for such year is in the second quartile as compared to such peer group companies, and 25% of such one-third vesting if the total return of the ETP units for such year is in the third quartile as compared to such peer group companies. Total return is defined as the sum of the per unit price appreciation in the market price of the ETP units for the year plus the aggregate per unit cash distributions received for the year. Non-cash compensation expense is recorded for these ETP awards based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded.

In October 2008, the Compensation Committee determined that, of the unit awards subject to the achievement of performance objectives, 25% of the ETP Common Units subject to such awards eligible to vest on September 1, 2007 became vested and 75% of the awards were forfeited based on ETP's performance for the twelve-month period ended August 31, 2008. In October 2008, the Compensation Committee approved a special grant of the new unit awards that entitled each holder to receive a number of ETP Common Units equal to the number of ETP Common Units forfeited as of September 1, 2007, which new unit awards became fully vested on October 15, 2008. These Compensation Committee actions affected all ETP employee unit awards including unit awards granted to ETP's executive officers.

Commencing in December 2007, ETP has also granted restricted unit awards to employees that vest over a specified time period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives. Upon vesting, ETP Common Units are issued. The unit awards under ETP's equity incentive plans generally require the continued employment of the recipient during the vesting period; however, the Compensation Committee has complete discretion to accelerate the vesting of unvested unit awards.

In 2008 and 2009, the Compensation Committee approved the grant of new unit awards, which vest over a five-year period at 20% per year, subject to continued employment through each specified vesting date. These unit awards entitle the recipients of the unit awards to receive, with respect to each ETP Common Unit subject to such award that has not either vested or been forfeited, a cash payment equal to each cash distribution per ETP Common Unit made by ETP on its Common Units promptly following each such distribution by ETP to its Unitholders. We refer to these rights as "distribution equivalent rights."

Prior to 2008 and 2009, units were generally awarded without distribution equivalent rights. For such awards, ETP calculated the grant-date fair value based on the market value of the underlying units, reduced by the present value of the distributions expected to be paid on the units during the requisite service period. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the distribution yield at that time.

Director Grants

Under ETP's equity incentive plans, ETP's non-employee directors each receive unvested ETP Common Units with a grant-date fair value of $50,000 each year. These non-employee director grants vest ratably over three years and do not entitle the holders to receive distributions during the vesting period.

Award Activity

The following table shows the activity of the ETP awards granted to employees and non-employee directors:

	Number of Units	Weighted Average Grant-Date Fair Value Per Unit
Unvested awards as of December 31, 2008	1,372,568	$ 36.83
Awards granted	763,190	43.56
Awards vested	(336,386)	36.02
Awards forfeited	(108,780)	39.17
Unvested awards as of December 31, 2009	1,690,592	39.88

The balance above for unvested awards as of December 31, 2008 includes 150,852 unit awards with a grant-date fair value of $43.96 per unit, which were granted prior to 2008 and were subject to a performance condition, as described above. These remaining performance awards vested in 2009, and none of the unvested unit awards outstanding as of December 31, 2009 contain performance conditions.

During the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the year ended August 31, 2007, the weighted average grant-date fair value per unit award granted was $43.56, $33.86, $42.46 and $43.73, respectively. The total fair value of awards vested was $14.7 million, $14.6 million, $3.3 million and $7.9 million, respectively based on the market price of ETP Common Units as of the vesting date. As of December 31, 2009, a total of 1,690,592 unit awards remain unvested, for which ETP expects to recognize a total of $50.9 million in compensation expense over a weighted average period of 1.9 years.

Related Party Awards

McReynolds Energy Partners, L.P., the general partner of which is owned and controlled by an ETE officer, awarded to certain officers of ETP certain rights related to units of ETE previously issued by ETE to such officer. These rights include the economic benefits of ownership of these ETE units based on a five year vesting schedule whereby the officer will vest in the ETE units at a rate of 20% per year. As these ETE units are conveyed to the recipients of these awards upon vesting from a partnership that is not owned or managed by ETE or ETP, none of the costs related to such awards are paid by ETP or ETE unless this partnership defaults under its obligations pursuant to these unit awards. As these units were outstanding prior to these awards, these awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE.

During the years ended December 31, 2008 and August 31, 2007, unvested rights related to 450,000 ETE common units and 675,000 ETE common units, respectively, with aggregate grant-date fair values of $10.3 million and $23.5 million, respectively, were awarded to ETP officers. During the year ended December 31, 2008, unvested rights related to 240,000 ETE common units were forfeited. During the years ended December 31, 2009 and 2008 and the four months ended December 31, 2007, ETP officers vested in rights related to 165,000 ETE common units, 135,000 ETE common units, and 55,000 ETE common units, respectively, with aggregate fair values upon vesting of $4.6 million, $3.5 million, and $1.9 million, respectively.

ETP is recognizing non-cash compensation expense over the vesting period based on the grant-date fair value of the ETE units awarded the ETP employees assuming no forfeitures. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, ETP recognized non-cash compensation expense, net of forfeitures, of $6.4 million, $3.5 million, $3.6 million and $5.2 million, respectively, as a result of these awards.

As of December 31, 2009, rights related to 530,000 ETE common units remain outstanding, for which we expect to recognize a total of $6.8 million in compensation expense over a weighted average period of 1.9 years.

8. INCOME TAXES:

The components of the federal and state income tax provision (benefit) of our taxable subsidiaries are summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Current expense (benefit):				
Federal	$ (8,851)	$ (180)	$ 2,990	$ 7,896
State	9,662	12,216	5,705	9,803
Total	811	12,036	8,695	17,699
Deferred expense (benefit):				
Federal	11,541	(5,634)	1,482	(4,598)
State	425	278	612	557
Total	11,966	(5,356)	2,094	(4,041)
Total income tax expense (benefit)	$ 12,777	$ 6,680	$ 10,789	$ 13,658

On May 18, 2006, the State of Texas enacted House Bill 3, which replaced the existing state franchise tax with a "margin tax." In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin, which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law's effective date of January 1, 2007. For the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $8.5 million, $10.5 million, $3.9 million and $6.9 million, respectively.

The effective tax rate differs from the statutory rate due primarily to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. The difference between the statutory rate and the effective rate is summarized as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Federal statutory tax rate	35.00%	35.00%	35.00%	35.00%
State income tax rate, net of federal benefit	1.03%	1.25%	1.82%	1.25%
Earnings not subject to tax at the Partnership level	(34.44)%	(35.48)%	(32.86)%	(34.25)%
Effective tax rate	1.59%	0.77%	3.96%	2.00%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of the deferred tax liability were as follows:

	December 31, 2009	December 31, 2008
Property, plant and equipment	$ 112,707	$ 105,032
Other, net	290	(3,846)
Total deferred tax liability	112,997	101,186
Less current deferred tax liability	—	589
Total long-term deferred tax liability	$ 112,997	$ 100,597

9. MAJOR CUSTOMERS AND SUPPLIERS:

Our major customers are in our natural gas operations. Our natural gas operations have a concentration of customers in natural gas transmission, distribution and marketing, as well as industrial end-users while our NGL operations have a concentration of customers in the refining and petrochemical industries. These concentrations of customers may impact our overall exposure to credit risk, either positively or negatively. Management believes that our portfolio of accounts receivable is sufficiently diversified to minimize any potential credit risk. No single customer accounted for 10% or more of our consolidated revenue.

We had gross segment purchases as a percentage of total purchases from major suppliers as follows:

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Propane segments				
Unaffiliated:				
M.P. Oils, Ltd.	15.1%	14.9%	14.2%	20.7%
Targa Liquids	14.3%	15.0%	15.9%	22.6%
Affiliated:				
Enterprise	50.3%	50.7%	50.6%	22.1%

Enterprise GP Holdings, L.P. and its subsidiaries (“Enterprise” or “EPE”) became related parties on May 7, 2007 as discussed in Note 13. Titan purchases the majority of its propane from Enterprise pursuant to an agreement that expires in March 2010 and contains renewal and extension options.

We sold our investment in M-P Energy in October 2007. In connection with the sale, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

This concentration of suppliers may impact our overall operations either positively or negatively. However, management believes that the diversification of suppliers is sufficient to enable us to purchase all of our supply needs at market prices without a material disruption of operations if supplies are interrupted from any of our existing sources. Although no assurances can be given that supplies of natural gas, propane and NGLs will be readily available in the future, we expect a sufficient supply to continue to be available.

10. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, ETP filed an application for FERC authority to construct and operate the Tiger pipeline. Approval from the FERC is still pending.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (“NGA”) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern’s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern’s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern’s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (“Order”). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area was placed in service effective March 2009.

Guarantees

MEP Guarantee

ETP has guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the "MEP Facility"), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP's guarantee may be proportionately increased or decreased if ETP's ownership percentage increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both ETP's credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP's ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

The commitment amount under the MEP Facility was originally $1.4 billion. In September 2009, MEP issued senior notes totaling $800.0 million, the proceeds of which were used to repay borrowings under the MEP Facility. The senior notes issued by MEP are not guaranteed by ETP or KMP. In October 2009, the members made additional capital contributions to MEP, which MEP used to further reduce the outstanding borrowings under the MEP Facility. Subsequent to this repayment, the commitment amount under the MEP Facility was reduced from $1.4 billion to $275.0 million.

As of December 31, 2009, MEP had $29.5 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility. Our contingent obligations with respect to ETP's 50% guarantee of MEP's outstanding borrowings and letters of credit were $14.7 million and $16.6 million, respectively, as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.3%.

Although ETP transferred substantially all of its interest in MEP on May 26, 2010, as discussed above in "Recent Developments" at Note 1, ETP will continue to guarantee 50% of MEP's obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify ETP for any costs related to the guarantee of payments under this facility.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the "FEP Facility"). ETP has guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP's guarantee may be proportionately increased or decreased if ETP's ownership percentage increases or decreases. The FEP Facility is available through May 11, 2012. Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both ETP's credit rating and that of KMP, with a maximum fee of 1.0%.

As of December 31, 2009, FEP had $355.0 million of outstanding borrowings issued under the FEP Facility. Our contingent obligation with respect to ETP's 50% guarantee of FEP's outstanding borrowings was $177.5 million as of December 31, 2009. The weighted average interest rate on the total amount outstanding as of December 31, 2009 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $19.8 million, $17.2 million, $9.4 million and $33.2 million for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, respectively.

Future minimum lease commitments for such leases are:

2010	$ 27,216
2011	24,786
2012	22,522
2013	20,385
2014	17,907
Thereafter	214,088

We have forward commodity contracts, which are expected to be settled by physical delivery. Short-term contracts, which expire in less than one year require delivery of up to 390,564 MMBtu/d. Long-term contracts require delivery of up to 125,551 MMBtu/d and extend through May 2014.

During fiscal year 2007, we entered into a long-term agreement with CenterPoint Energy Resources Corp ("CenterPoint") to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of the agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel storage facility.

We have a transportation agreement with TXU Portfolio Management Company, LP ("TXU Shipper") to transport a minimum of 100,000 MMBtu per year through 2012. We also have two natural gas storage agreements with TXU Shipper to store gas at two natural gas facilities that are part of the ET Fuel System that expire in 2012. As of December 31, 2009 and 2008 and August 31, 2007, respectively, the Partnership was entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month periods ended each May 31st. As a result, the Partnership recognized approximately $11.7 million, $10.7 million and $10.8 million in additional fees during the second quarters of 2009 and 2008 and the third fiscal quarter of 2007, respectively.

We have signed long-term agreements with several parties committing firm transportation volumes into the East Texas pipeline. Those commitments include an agreement with XTO Energy Inc. ("XTO") to deliver approximately 200,000 MMBtu/d of natural gas into the pipeline that expires in June 2012. Exxon Mobil Corporation ("ExxonMobil") and XTO announced an agreement whereby ExxonMobil will acquire XTO. The pending acquisition, expected to be completed in the second quarter of 2010, is not expected to result in any changes to these commitments.

We also have two long-term agreements committing firm transportation volumes on certain of our transportation pipelines. The two contracts require an aggregated capacity of approximately 238,000 MMBtu/d of natural gas and extend through 2011.

Titan has a purchase contract with Enterprise (see Note 13) to purchase the majority of Titan's propane requirements. The contract continues until March 2010 and contains renewal and extension options. The contract contains various service level agreements between the parties.

In connection with the sale of our investment in M-P Energy in October 2007, we executed a propane purchase agreement for approximately 90.0 million gallons per year through 2015 at market prices plus a nominal fee.

We have commitments to make capital contributions to our joint ventures, for which we expect to make capital contributions of between $90 million and $105 million during 2010.

Litigation and Contingencies

The Operating Companies may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us and our Operating Companies from material expenses related to product liability, personal injury or property damage in the future.

FERC and Related Matters. On July 26, 2007, the FERC issued to ETP an Order to Show Cause and Notice of Proposed Penalties (the “Order and Notice”) that contains allegations that ETP violated FERC rules and regulations. The FERC alleged that ETP engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from ETP’s commodities derivatives positions and from certain of ETP’s index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods ETP violated the FERC’s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that ETP violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of ETP’s intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that ETP manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC’s Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP’s trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC’s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, ETP entered into a settlement agreement with the FERC’s Enforcement Staff with respect to the pending FERC claims against ETP and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against ETP and provides that ETP make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against ETP by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement ETP does not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with ETP’s alleged conduct related to the FERC claims. The settlement agreement also requires ETP to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ’s recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ’s fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, ETP remains a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The plaintiff appealed this determination to the First Court of Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010 the First Circuit Court of Appeals issued an opinions affirming the judgment of the lower court granting ETP's motion for summary judgment.

In October 2007, a consolidated class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, ETP had the market power to manipulate index prices, and that ETP used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit ETP's natural gas physical and financial trading positions, and that ETP intentionally submitted price and volume trade information to trade publications. This complaint also alleges that ETP violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by ETP manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, ETP filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, ETP filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint.

On March 17, 2008, a second class action complaint was filed against ETP in the United States District Court for the Southern District of Texas. This action alleges that ETP engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period ETP exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit its own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, ETP filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. ETP opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted ETP's motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

ETP is expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. ETP record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, ETP made the $5.0 million payment and established the $25.0 million fund in October 2009. ETP expects the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which ETP expects to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount ETP becomes obligated to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, ETP will review the amount of our accrual related to these matters as developments related to these matters occur and ETP will adjust its accrual if ETP determines that it is probable that the amount it may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As ETP's accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce ETP's cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, ETP may experience a material adverse impact on its results of operations and our liquidity.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were defendants in litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the "Cushion Gas Litigation". In 2004, ETC OLP (a subsidiary of (ETP) acquired the HPL Entities from AEP, and due to the potential liability of the HPL Entities pursuant to the Cushion Gas Litigation, AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. AEP is appealing the court decision. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A pursuant to this court decision.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of December 31, 2009 and 2008, accruals of approximately $11.1 million and $8.5 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

As of December 31, 2008, an accrual of $21.0 million was recorded as accrued and other current liabilities and other non-current liabilities on our consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters, and we did not have any such accruals as of December 31, 2009.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental laws and regulations that require expenditures for remediation at operating facilities and waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline and processing business, and there can be no assurance that significant costs and liabilities will not be incurred. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational health, and the handling, storage, use, and disposal of hazardous materials to prevent material environmental or other damage, and to limit the financial liability, which could result from such events. However, some risk of environmental or other damage is inherent in the natural gas pipeline and processing business, as it is with other entities engaged in similar businesses.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for contamination by polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.6 million. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the EPA’s Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

In July 2001, HOLP acquired a company that had previously received a request for information from the U.S. Environmental Protection Agency (the “EPA”) regarding potential contribution to a widespread groundwater contamination problem in San Bernardino, California, known as the Newmark Groundwater Contamination. Although the EPA has indicated that the groundwater contamination may be attributable to releases of solvents from a former military base located within the subject area that occurred long before the facility acquired by HOLP was constructed, it is possible that the EPA may seek to recover all or a portion of groundwater remediation costs from private parties under the Comprehensive Environmental Response, Compensation, and Liability Act (commonly called Superfund). We have not received any follow-up correspondence from the EPA on the matter since our acquisition of the predecessor company in 2001. Based upon information currently available to HOLP, it is believed that HOLP’s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our December 31, 2009 or our December 31, 2008 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in cleanup technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of December 31, 2009 and 2008, accruals on an undiscounted basis of $12.6 million and $13.3 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for all of the above environmental matters is adequate to cover the potential exposure for clean-up costs.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation (“DOT”) under the Pipeline Hazardous Materials Safety Administration (“PHMSA”), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as (“high consequence areas.”) Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the years ended December 31, 2009 and 2008, $31.4 million and $23.3 million, respectively, of capital costs and $18.5 million and $13.1 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

11. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

See Note 2 for further discussion of our accounting for derivative instruments and hedging activities.

Commodity Price Risk

The following table details the outstanding commodity-related derivatives:

		December 31, 2009		December 31, 2008	
	Commodity	Notional Volume MMBtu	Maturity	Notional Volume MMBtu	Maturity
Mark to Market Derivatives					
Basis Swaps IFERC/NYMEX	Gas	72,325,000	2010-2011	15,720,000	2009-2011
Swing Swaps IFERC	Gas	(38,935,000)	2010	(58,045,000)	2009
Fixed Swaps/Futures	Gas	4,852,500	2010-2011	(20,880,000)	2009-2010
Options - Puts	Gas	2,640,000	2010	—	N/A
Options - Calls	Gas	(2,640,000)	2010	—	N/A
Forwards/Swaps - in Gallons	Propane/Ethane	6,090,000	2010	47,313,002	2009
Fair Value Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(22,625,000)	2010	—	N/A
Fixed Swaps/Futures	Gas	(27,300,000)	2010	—	N/A
Hedged Item - Inventory	Gas	27,300,000	2010	—	N/A
Cash Flow Hedging Derivatives					
Basis Swaps IFERC/NYMEX	Gas	(13,225,000)	2010	(9,085,000)	2009
Fixed Swaps/Futures	Gas	(22,800,000)	2010	(9,085,000)	2009
Forwards/Swaps - in Gallons	Propane/Ethane	20,538,000	2010	—	N/A

We expect gains of $2.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

As of July 2008, we no longer engage in the trading of commodity derivative instruments that are not substantially offset by physical or other commodity derivative positions. As a result, we no longer have any material exposure to market risk from such activities. The derivative contracts that were previously entered into for trading purposes were recognized in the consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in revenue in the consolidated statements of operations on a net basis. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.2 million for the year ended December 31, 2008, net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007 and net gains of approximately $2.2 million for the fiscal year ended August 31, 2007. There were no gains or losses associated with trading activities during the year ended December 31, 2009.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. We have previously managed a portion of our current and future interest rate exposures by utilizing interest rate swaps. As of December 31, 2009, we do not have any interest rate swaps outstanding.

In December 2009, we settled forward starting swaps with notional amounts of $500.0 million for a cash payment of $11.1 million. In April 2009, we terminated forward starting swaps with notional amounts of $100.0 million and $150.0 million for an insignificant amount.

In January 2010, we entered into interest rate swaps with notional amounts of $350.0 million and $750.0 million to pay a floating rate based on LIBOR and receive a fixed rate that mature in July 2013 and February 2015, respectively. These swaps hedge against changes in the fair value of our fixed rate debt.

Derivative Summary

The following table provides a balance sheet overview of ETP's derivative assets and liabilities as of December 31, 2009 and December 31, 2008:

		Fair Value of Derivative Instruments			
		Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
Derivatives designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	$ 669	$ 10,665	$ (24,035)	$ (1,504)
Commodity Derivatives	Price Risk Management Assets/Liabilities	8,443	918	(201)	(119)
Total derivatives designated as hedging instruments		$ 9,112	$ 11,583	$ (24,236)	$ (1,623)
Derivatives not designated as hedging instruments:					
Commodity Derivatives (margin deposits)	Deposits Paid to Vendors	72,851	432,614	(36,950)	(335,685)
Commodity Derivatives	Price Risk Management Assets/Liabilities	3,928	17,244	(241)	(55,954)
Interest Rate Swap Derivatives	Price Risk Management Assets/Liabilities	—	—	—	(51,643)
Total derivatives not designated as hedging instruments		$ 76,779	$ 449,858	$ (37,191)	$ (443,282)
Total derivatives		$ 85,891	$ 461,441	$ (61,427)	$ (444,905)

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives. We exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the consolidated balance sheets. ETP had net deposits with counterparties of $79.7 million and $78.2 million as of December 31, 2009 and December 31, 2008, respectively.

The following tables detail the effect of ETP's derivative assets and liabilities in the consolidated statements of operations for the periods presented:

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 3,143	$ 17,461	$ 21,406	$ 181,765
Interest Rate Swap Derivatives	Interest Expense	—	—	—	(4,719)
Total		$ 3,143	$ 17,461	$ 21,406	$ 177,046

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ 9,924	$ 42,874	$ 8,673	$ 162,340
Interest Rate Swap Derivatives	Interest Expense	287	646	(51)	920
Total		$ 10,211	$ 43,520	$ 8,622	$ 163,260

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective and Ineffective Portion)	Amount of Gain/(Loss) Recognized in Income on Ineffective Portion of Derivatives			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in cash flow hedging relationships:					
Commodity Derivatives	Cost of Products Sold	$ —	$ (8,347)	$ 8,472	$ 183
Interest Rate Swap Derivatives	Interest Expense	—	—	—	(1,813)
Total		$ —	$ (8,347)	$ 8,472	$ (1,630)

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
		2009	2008	2007	2007
Derivatives in fair value hedging relationships:					
Commodity Derivatives (including hedged items)	Cost of Products Sold	$ 60,045	$ —	$ —	$ —
Total		$ 60,045	$ —	$ —	$ —

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain/(Loss) Recognized in Income on Derivatives			
		Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
Derivatives not designated as hedging instruments:					
Commodity Derivatives	Cost of Products Sold	$ 99,807	$ 12,478	$ 9,886	$ 30,028
Trading Commodity Derivatives	Revenue	—	(28,283)	(2,298)	5,228
Interest Rate Swap Derivatives	Gains (Losses) on Non-hedged Interest Rate Derivatives	39,239	(50,989)	(1,013)	31,032
Total		$ 139,046	$ (66,794)	$ 6,575	$ 66,288

We recognized an $18.6 million unrealized loss, a $35.5 million unrealized gain, a $13.2 million unrealized gain and an $8.5 million unrealized loss on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships and amounts classified as trading activity) for the years ended December 31, 2009 and 2008, four months ended December 31, 2007 and the year August 31, 2007, respectively. In addition, for the year ended December 31, 2009, we recognized unrealized gains of $48.6 million on commodity derivatives and related hedged inventory accounted for as fair value hedges. There were no unrealized gains or losses on fair value hedging commodity derivatives in the prior years since we commenced fair hedge accounting on our storage inventory in April 2009.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties’ financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our consolidated balance sheet and recognized in net income or other comprehensive income.

12. RETIREMENT BENEFITS:

ETP sponsors a 401(k) savings plan, which covers virtually all employees. Employer matching contributions are calculated using a formula based on employee contributions. Prior to 2009, employer matching contributions were discretionary. We made matching contributions of $9.8 million, $9.7 million, $2.6 million and $8.5 million to the 401(k) savings plan for the years ended December 31, 2009 and 2008, the four months ended December 31, 2007, and the fiscal year ended August 31, 2007, respectively.

13. RELATED PARTY TRANSACTIONS:

On May 7, 2007, Ray Davis, previously the Co-Chairman of ETE and Co-Chairman and Co-Chief Executive Officer of ETP (retired August 15, 2007), and Natural Gas Partners VI, L.P. (“NGP”) and affiliates of each, sold approximately 38,976,090 ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise. In addition to the purchase of ETE Common Units, Enterprise acquired a non-controlling equity interest in ETE’s General Partner, LE GP, LLC (“LE GP”). As a result of these transactions, EPE and its subsidiaries are considered related parties for financial reporting purposes.

On December 23, 2009, Dan L. Duncan and Ralph S. Cunningham were appointed as directors of ETE’s general partner. Mr. Duncan is Chairman and a director of EPE Holdings, LLC, the general partner of Enterprise;

Chairman and a director of Enterprise Products GP, LLC, the general partner of Enterprise Products Partners L.P., or EPD; and Group Co-Chairman of EPCO, Inc. TEPPCO Partners, L.P., or TEPPCO, is also an affiliate of EPE. Dr. Cunningham is the President and Chief Executive Officer of EPE Holdings, LLC, the general partner of Enterprise. These entities and other affiliates of Enterprise are referred to herein collectively as the “Enterprise Entities.” Mr. Duncan directly or indirectly beneficially owns various interests in the Enterprise Entities, including various general partner interests and approximately 77.1% of the common units of Enterprise and approximately 34% of the common units of EPD. On October 26, 2009, TEPPCO became a wholly owned subsidiary of Enterprise.

Our propane operations routinely enter into purchases and sales of propane with certain of the Enterprise Entities, including purchases under a long-term contract of Titan to purchase the majority of its propane requirements through certain of the Enterprise Entities. This agreement was in effect prior to our acquisition of Titan in 2006, and expires in March 2010 and contains renewal and extension options.

From time to time, our natural gas operations purchase from, and sell to, the Enterprise Entities natural gas and NGLs, in the ordinary course of business. We have a monthly natural gas storage contract with TEPPCO. Our natural gas operations and the Enterprise Entities transport natural gas on each other’s pipelines and share operating expenses on jointly-owned pipelines.

The following table presents sales to and purchases from affiliates of Enterprise. Amounts reflected below for the year ended August 31, 2007 include transactions beginning on May 7, 2007, the date Enterprise became an affiliate. Volumes are presented in thousands of gallons for propane and NGLs and in billions of Btus for natural gas:

		Years Ended December 31,				Four Months Ended December 31,		Year Ended August 31,	
		2009		2008		2007		2007	
	Product	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars	Volumes	Dollars
Propane Operations:									
Sales	Propane	20,370	$ 14,046	13,230	$ 19,769	2,982	$ 4,619	1,470	$ 1,725
	Derivatives	—	5,915	—	2,442	—	1,857	—	22
Purchases	Propane	307,525	$ 305,148	318,982	$ 472,816	125,141	$ 192,580	61,660	$ 74,688
	Derivatives	—	38,392	—	20,993	—	—	—	1
Natural Gas Operations:									
Sales	NGLs	477,908	$ 374,020	58,361	$ 96,974	3,240	$ 4,726	464	$ 648
	Natural Gas	11,532	44,212	6,256	52,205	2,036	11,452	1,495	9,768
	Fees	—	(3,899)	—	5,093	—	610	—	—
Purchases	Natural Gas Imbalances	176	$ 1,164	3,488	$ (6,485)	313	$ (911)	3,120	$ 22,677
	Natural Gas	10,561	49,559	13,457	120,837	3,577	23,341	1,541	7,501
	Fees	—	(2,195)	—	876	—	311	—	—

As of December 31, 2009 and 2008, Titan had forward mark-to-market derivatives for approximately 6.1 million and 45.2 million gallons of propane at a fair value asset of $3.3 million and a fair value liability of $40.1 million, respectively, with Enterprise. In addition, as of December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 20.5 million gallons of propane at a fair value asset of $8.4 million with Enterprise.

The following table summarizes the related party balances with Enterprise on our consolidated balance sheets:

	December 31, 2009	December 31, 2008
Natural Gas Operations:		
Accounts receivable	$ 47,005	$ 11,558
Accounts payable	3,518	567
Imbalance payable	694	(547)
Propane Operations:		
Accounts receivable	$ 3,386	$ 111
Accounts payable	31,642	33,308

Accounts receivable from related companies excluding Enterprise consist of the following:

	December 31, 2009	December 31, 2008
ETE	$ 5,255	$ 2,632
MEP	632	2,805
McReynolds Energy	—	202
Energy Transfer Technologies, Ltd.	—	16
Others	870	449
Total accounts receivable from related companies excluding Enterprise	$ 6,757	$ 6,104

Effective August 17, 2009, ETP acquired 100% of the membership interests of Energy Transfer Group, L.L.C. (“ETG”), which owns all of the partnership interests of Energy Transfer Technologies, Ltd. (“ETT”). ETT provides compression services to customers engaged in the transportation of natural gas, including ETP. The membership interests of ETG were contributed to us by Mr. Warren and by two entities, one of which is controlled by a director of our General Partner’s general partner and the other of which is controlled by a member of ETP’s management. In exchange, the former members acquired the right to receive (in cash or Common Units), future amounts to be determined based on the terms of the contribution arrangement. These contingent amounts are to be determined in 2014 and 2017, and the former members of ETG may receive payments contingent on the acquired operations performing at a level above the average return required by ETP for approval of its own growth projects during the period since acquisition. In addition, the former members may be required to make cash payments to us under certain circumstances. In connection with this transaction, we assumed liabilities of $33.5 million and recorded goodwill of $1.7 million.

Prior to our acquisition of ETG in August 2009, our natural gas midstream and intrastate transportation and storage operations secured compression services from ETT. The terms of each arrangement to provide compression services were, in the opinion of independent directors of the General Partner, no more or less favorable than those available from other providers of compression services. During the years ended December 31, 2009 (through the ETG acquisition date) and 2008, the four months ended December 31, 2007 and the fiscal year ended August 31, 2007, we made payments totaling $3.4 million, $9.4 million, $0.8 million and $2.4 million, respectively, to ETG for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations.

The Chief Executive Officer (“CEO”) of our General Partner, Mr. Kelcy Warren, voluntarily determined that after 2007, his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. We recorded non-cash compensation expense and an offsetting capital contribution of $1.3 million ($0.5 million in salary and $0.8 million in accrued bonuses) for each of the years ended December 31, 2009 and 2008 as an estimate of the reasonable compensation level for the CEO position.

14. COMPARATIVE INFORMATION FOR THE FOUR MONTHS ENDED DECEMBER 31, 2007:

The unaudited financial information for the four month period ended December 31, 2006, contained herein is presented for comparative purposes only and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with accounting principles generally accepted in the United States of America. Certain financial statement amounts have been adjusted due to the adoption of new accounting standards in 2009. See Note 2.

ENERGY TRANSFER PARTNERS, LLC AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
REVENUES:		
Natural gas operations	$ 1,832,192	$ 1,668,667
Retail propane	471,494	409,821
Other	45,824	83,978
Total revenues	2,349,510	2,162,466
COSTS AND EXPENSES:		
Cost of products sold - natural gas operations	1,343,237	1,382,473
Cost of products sold - retail propane	315,698	256,994
Cost of products sold - other	14,719	50,376
Operating expenses	221,757	173,365
Depreciation and amortization	71,333	48,767
Selling, general and administrative	59,167	40,638
Total costs and expenses	2,025,911	1,952,613
OPERATING INCOME	323,599	209,853
OTHER INCOME (EXPENSE):		
Interest expense, net of interest capitalized	(66,304)	(54,953)
Equity in earnings (losses) of affiliates	(94)	4,743
Gain on disposal of assets	14,310	2,212
Other, net	1,065	2,163
INCOME BEFORE INCOME TAX EXPENSE	272,576	164,018
Income tax expense	10,789	3,120
NET INCOME	261,787	160,898
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	261,778	160,891
NET INCOME ATTRIBUTABLE TO MEMBER	$ 9	$ 7

ENERGY TRANSFER PARTNERS, LLC AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)
(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
Net income	$ 261,787	$ 160,898
Other comprehensive income (loss), net of tax:		
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(17,269)	(23,698)
Change in value of derivative instruments accounted for as cash flow hedges	21,626	152,653
Change in value of available-for-sale securities	(98)	(401)
	4,259	128,554
Comprehensive income	266,046	289,452
Less: Comprehensive income attributable to noncontrolling interest	266,037	289,445
Comprehensive income attributable to partners	$ 9	$ 7

ENERGY TRANSFER PARTNERS, LLC AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Four Months Ended December 31, 2007	Four Months Ended December 31, 2006
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 261,787	$ 160,898
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	71,333	48,767
Amortization of finance costs charged to interest	1,435	1,068
Provision for loss on accounts receivable	544	563
Non-cash unit-based compensation expense	8,114	4,385
Non-cash executive compensation expense	442	—
Deferred income taxes	1,003	(2,234)
Gains on disposal of assets	(14,310)	(2,212)
Distributions in excess of (less than) equity in earnings of affiliates, net	4,448	(4,743)
Other non-cash	(2,069)	(76)
Net change in operating assets and liabilities, net of effects of acquisitions	(90,574)	238,989
Net cash provided by operating activities	242,153	445,405
CASH FLOWS FROM INVESTING ACTIVITIES:		
Net cash paid for acquisitions	(337,092)	(67,089)
Capital expenditures	(651,228)	(336,473)
Contributions in aid of construction costs	3,493	4,984
(Advances to) repayments from affiliates, net	(32,594)	(953,247)
Proceeds from the sale of assets	21,478	7,644
Net cash used in investing activities	(995,943)	(1,344,181)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	1,741,547	1,667,810
Principal payments on debt	(1,062,272)	(1,737,788)
Subsidiary equity offerings, net of issue costs	234,887	1,200,000
Distributions to member	(6)	(4)
Distributions to noncontrolling interests	(172,390)	(125,770)
Debt issuance costs	(211)	(9,451)
Net cash provided by financing activities	741,555	994,797
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(12,235)	96,021
CASH AND CASH EQUIVALENTS, beginning of period	68,750	26,070
CASH AND CASH EQUIVALENTS, end of period	$ 56,515	$ 122,091

15. SUPPLEMENTAL INFORMATION:

Following are the financial statements of the Company, which are included to provide additional information with respect to the Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS
(Dollars in thousands)

	December 31, 2009	December 31, 2008
ASSETS:		
Investments in affiliates	$ 18	$ 16
EQUITY:		
Member's Equity	$ 18	$ 16

STATEMENTS OF OPERATIONS
(Dollars in thousands)

	Years Ended December 31,		Four Months Ended December 31,	Year Ended August 31,
	2009	2008	2007	2007
Equity in earnings of affiliates	$ 36	$ 32	$ 9	$ 24
NET INCOME	$ 36	$ 32	$ 9	$ 24

STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Years Ended December 31, 2009	Years Ended December 31, 2008	Four Months Ended December 31, 2007	Year Ended August 31, 2007
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 34	$ 33	$ 6	$ 21
CASH FLOWS FROM FINANCING ACTIVITIES:				
Distributions to member	(34)	(33)	(6)	(21)
Net cash provided by financing activities	(34)	(33)	(6)	(21)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	—	—	—	—
CASH AND CASH EQUIVALENTS, beginning of period	—	—	—	—
CASH AND CASH EQUIVALENTS, end of period	$ —	$ —	$ —	$ —

Exhibit 99.6

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 78,879	$ 68,253
Marketable securities	3,002	6,055
Accounts receivable, net of allowance for doubtful accounts of $6,378 and $6,338 as of June 30, 2010 and December 31, 2009, respectively	471,288	566,522
Accounts receivable from related companies	49,362	57,148
Inventories	231,057	389,954
Exchanges receivable	9,985	23,136
Price risk management assets	24	12,371
Other current assets	91,161	148,423
Total current assets	934,758	1,271,862
PROPERTY, PLANT AND EQUIPMENT	10,329,313	9,649,405
ACCUMULATED DEPRECIATION	(1,126,660)	(979,158)
	9,202,653	8,670,247
ADVANCES TO AND INVESTMENTS IN AFFILIATES	7,587	663,298
LONG-TERM PRICE RISK MANAGEMENT ASSETS	4,237	—
GOODWILL	803,334	775,093
INTANGIBLES AND OTHER ASSETS, net	433,171	384,109
Total assets	$ 11,385,740	$ 11,764,609

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 315,601	$ 358,997
Accounts payable to related companies	7,623	38,842
Exchanges payable	11,323	19,203
Price risk management liabilities	2,248	442
Accrued and other current liabilities	459,146	365,175
Current maturities of long-term debt	40,733	40,923
Total current liabilities	836,674	823,582
LONG-TERM DEBT, less current maturities	6,049,531	6,177,046
OTHER NON-CURRENT LIABILITIES	134,385	134,807
COMMITMENTS AND CONTINGENCIES (Note 12)		
EQUITY:		
Member’s equity	18	18
Noncontrolling interest	4,365,132	4,629,156
Total equity	4,365,150	4,629,174
Total liabilities and equity	$ 11,385,740	$ 11,764,609

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
REVENUES:				
Natural gas operations	$1,045,946	$ 948,233	$2,352,655	$2,060,188
Retail propane	197,147	179,770	730,586	667,677
Other	24,613	23,814	56,446	54,052
Total revenues	1,267,706	1,151,817	3,139,687	2,781,917
COSTS AND EXPENSES:				
Cost of products sold – natural gas operations	654,239	542,004	1,566,845	1,274,117
Cost of products sold – retail propane	110,282	78,070	415,263	298,292
Cost of products sold – other	6,336	5,919	13,614	12,723
Operating expenses	169,533	176,681	340,281	358,454
Depreciation and amortization	83,877	76,174	167,153	148,777
Selling, general and administrative	44,254	53,748	93,026	109,492
Total costs and expenses	1,068,521	932,596	2,596,182	2,201,855
OPERATING INCOME	199,185	219,221	543,505	580,062
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(103,017)	(100,680)	(207,982)	(182,729)
Equity in earnings of affiliates	4,072	1,673	10,253	2,170
Gains (losses) on disposal of assets	1,385	181	(479)	(245)
Gains on non-hedged interest rate derivatives	—	36,842	—	50,568
Allowance for equity funds used during construction	4,298	(1,839)	5,607	18,588
Impairment of investment in affiliate	(52,620)	—	(52,620)	—
Other, net	(5,893)	(182)	(4,936)	870
INCOME BEFORE INCOME TAX EXPENSE	47,410	155,216	293,348	469,284
Income tax expense	4,569	4,559	10,493	11,491
NET INCOME	42,841	150,657	282,855	457,793
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	42,831	150,648	282,836	457,775
NET INCOME ATTRIBUTABLE TO MEMBER	$ 10	$ 9	$ 19	$ 18

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Dollars in thousands)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Net income	$ 42,841	$ 150,657	$ 282,855	$ 457,793
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(6,112)	856	(12,618)	(9,693)
Change in value of derivative instruments accounted for as cash flow hedges	(9,452)	1,336	24,634	(50)
Change in value of available-for-sale securities	(724)	3,657	(3,053)	3,708
	(16,288)	5,849	8,963	(6,035)
Comprehensive income	26,553	156,506	291,818	451,758
Less: Comprehensive income attributable to noncontrolling interest	26,543	156,497	291,799	451,740
Comprehensive income attributable to member	$ 10	$ 9	$ 19	$ 18

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF EQUITY

FOR THE SIX MONTHS ENDED JUNE 30, 2010

(Dollars in thousands)
(unaudited)

	Member's Equity	Noncontrolling Interest	Total
Balance, December 31, 2009	$ 18	$ 4,629,156	$4,629,174
Redemption of units in connection with MEP transaction	—	(612,039)	(612,039)
Distributions to members	(19)	—	(19)
Distributions to noncontrolling interests	—	(531,792)	(531,792)
Subsidiary units issued for cash	—	574,522	574,522
Tax effect of remedial income allocation from tax amortization of goodwill	—	(1,702)	(1,702)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	14,563	14,563
Non-cash executive compensation	—	625	625
Other comprehensive income, net of tax	—	8,963	8,963
Net income	19	282,836	282,855
Balance, June 30, 2010	$ 18	$ 4,365,132	$4,365,150

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

ENERGY TRANSFER PARTNERS, L.L.C. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 886,147	$ 704,038
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(153,385)	(6,362)
Capital expenditures (excluding allowance for equity funds used during construction)	(608,497)	(512,534)
Contributions in aid of construction costs	7,957	2,349
Advances to affiliates, net of repayments	(5,596)	(364,000)
Proceeds from the sale of assets	9,124	5,033
Net cash used in investing activities	(750,397)	(875,514)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	265,642	1,587,943
Principal payments on debt	(410,178)	(1,501,487)
Subsidiary equity offerings, net of issue costs	574,522	578,924
Distributions to member	(19)	(17)
Distributions to noncontrolling interests	(531,792)	(463,815)
Subsidiary redemption of units	(23,299)	—
Debt issuance costs	—	(7,746)
Net cash provided by (used in) financing activities	(125,124)	193,802
INCREASE IN CASH AND CASH EQUIVALENTS	10,626	22,326
CASH AND CASH EQUIVALENTS, beginning of period	68,253	91,962
CASH AND CASH EQUIVALENTS, end of period	$ 78,879	$ 114,288

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

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2009, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.L.C., and its subsidiaries (the “Company,” “we” or “ETP LLC”) as of June 30, 2010 and for the six months ended June 30, 2010 and 2009, have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for interim consolidated financial information. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Company’s operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners, L.L.C. and its subsidiaries as of June 30, 2010, and the Company’s results of operations and cash flows for the three and six months ended June 30, 2010 and 2009. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto of ETP LLC and subsidiaries presented as Exhibit 99.5 to the Energy Transfer Equity, L.P. Form 8-K filed on August 11, 2010.

Certain prior period amounts have been reclassified to conform to the 2010 presentation. These reclassifications had no impact on net income or total equity.

ETP LLC is the General Partner of Energy Transfer Partners GP, L.P. (“ETP GP”), a Delaware limited partnership formed in August 2000, with a 0.01% general partner interest. ETP GP is the General Partner and owns the general partner interests of Energy Transfer Partners, L.P., a publicly-traded master limited partnership (“ETP”). The condensed consolidated financial statements of the Company presented herein include ETP’s operating subsidiaries described below.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are primarily conducted through our operating subsidiaries (collectively the “Operating Companies”) as follows:

- La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“ETC OLP”), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, Utah and Colorado. Our intrastate transportation and storage operations primarily focus on transporting natural gas through our Oasis pipeline, ET Fuel System, East Texas pipeline and HPL System. Our midstream operations focus on the gathering, compression, treating, conditioning and processing of natural gas, primarily on or through our Southeast Texas System and North Texas System, and marketing activities. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance-Uinta Basin of Colorado and Utah.
- Energy Transfer Interstate Holdings, LLC (“ET Interstate”), a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
  - Transwestern Pipeline Company, LLC (“Transwestern”), a Delaware limited liability company engaged in interstate transportation of natural gas. Interstate revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.

- ETC Fayetteville Express Pipeline, LLC (“ETC FEP”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC (“ETC Tiger”), a Delaware limited liability company formed to engage in interstate transportation of natural gas.

- ETC Compression, LLC (“ETC Compression”), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Heritage Operating, L.P. (“HOLP”), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan Energy Partners, L.P. (“Titan”), a Delaware limited partnership also engaged in retail propane operations.

The Company, ETP GP, the Operating Companies and their subsidiaries are collectively referred to in this report as “we,” “us,” “ETP LLC,” or the “Company.”

Recent Developments

On May 26, 2010, ETP completed the transfer of the membership interests in ETC Midcontinent Express Pipeline III, L.L.C. (“ETC MEP III”) to ETE pursuant to the Redemption and Exchange Agreement between ETP and ETE, dated as of May 10, 2010 (the “MEP Transaction”). ETC MEP III owns a 49.9% membership interest in Midcontinent Express Pipeline LLC (“MEP”), ETP’s joint venture with Kinder Morgan Energy Partners, L.P. (“KMP”) that owns and operates the Midcontinent Express Pipeline. In exchange for the membership interests in ETC MEP III, ETP redeemed 12,273,830 ETP common units that were previously owned by ETE. ETP also paid $23.3 million to ETE upon closing of the MEP Transaction for adjustments related to capital expenditures and working capital changes of MEP. This closing adjustment is subject to change during a final review period as defined in the contribution agreement. ETP also granted ETE an option that cannot be exercised until May 27, 2011, to acquire the membership interests in ETC Midcontinent Express Pipeline II, L.L.C. (“ETC MEP II”). ETC MEP II owns a 0.1% membership interest in MEP. In conjunction with this transfer of ETP interest in ETC MEP III, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest in ETC MEP III to its estimated fair value.

As part of the MEP Transaction, on May 26, 2010, ETE completed the contribution of the membership interests in ETC MEP III and the assignment of its rights under the option to acquire the membership interests in ETC MEP II to a subsidiary of Regency Energy Partners LP (“Regency”) in exchange for 26,266,791 Regency common units. In addition, ETE acquired a 100% equity interest in the general partner entities of Regency from an affiliate of GE Energy Financial Services, Inc. (“GE EFS”).

ETP continues to guarantee 50% of MEP’s obligations under MEP’s $175.4 million senior revolving credit facility, with the remaining 50% of MEP’s obligations guaranteed by KMP; however, Regency has agreed to indemnify ETP for any costs related to the guaranty of payments under this facility. See Note 12.

2. <u>ESTIMATES:</u>

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for 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.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month’s financial results for the midstream and intrastate transportation and storage operations are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month’s financial statements. Management believes that the operating results estimated for the three and six months ended June 30, 2010 represent the actual results in all material respects.

Some of the other significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, fair value measurements used in the goodwill impairment test, market value of inventory, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

3. ACQUISITIONS:

During the six months ended June 30, 2010, ETP purchased a natural gas gathering company, which provides dehydration, treating, redelivery and compression services on a 120-mile pipeline system in the Haynesville Shale for approximately $150.0 million in cash, excluding certain adjustments as defined in the purchase agreement. In connection with this transaction, ETP recorded customer contracts of $68.2 million and goodwill of $27.3 million. See further discussion at Note 6.

4. CASH, CASH EQUIVALENTS AND SUPPLEMENTAL CASH FLOW INFORMATION:

Cash and cash equivalents include all cash on hand, demand deposits, and investments with original maturities of three months or less. We consider cash equivalents to include short-term, highly liquid investments that are readily convertible to known amounts of cash and that are subject to an insignificant risk of changes in value.

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, our cash and cash equivalents may be uninsured or in deposit accounts that exceed the Federal Deposit Insurance Corporation insurance limit.

Non-cash investing activities cash flow information are as follows:

	Six Months Ended June 30,	
	2010	2009
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$ 73,432	$ 90,268
Transfer of MEP joint venture interest in exchange for redemption of ETP Common Units	$ 588,741	$ —

5. INVENTORIES:

Inventories consisted of the following:

	June 30, 2010	December 31, 2009
Natural gas and NGLs, excluding propane	$ 89,751	$ 157,103
Propane	49,016	66,686
Appliances, parts and fittings and other	92,290	166,165
Total inventories	$231,057	$ 389,954

We utilize commodity derivatives to manage price volatility associated with our natural gas inventory. We designate commodity derivatives as fair value hedges for accounting purposes. Changes in fair value of the designated hedged inventory have been recorded in inventory on our condensed consolidated balance sheets and have been recorded in cost of products sold in our condensed consolidated statements of operations.

6. GOODWILL, INTANGIBLES AND OTHER ASSETS:

A net increase in goodwill of $28.2 million was recorded during the six months ended June 30, 2010, primarily due to $27.3 million from the acquisition of the natural gas gathering company referenced in Note 3, which is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $68.2 million with useful lives of 46 years.

Components and useful lives of intangibles and other assets were as follows:

	June 30, 2010		December 31, 2009	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$ 245,574	$ (67,178)	$ 176,858	$ (58,761)
Noncompete agreements (3 to 15 years)	22,931	(12,578)	24,139	(12,415)
Patents (9 years)	750	(76)	750	(35)
Other (10 to 15 years)	1,320	(440)	478	(397)
Total amortizable intangible assets	270,575	(80,272)	202,225	(71,608)
Non-amortizable intangible assets –				
Trademarks	76,086	—	75,825	—
Total intangible assets	346,661	(80,272)	278,050	(71,608)
Other assets:				
Financing costs (3 to 30 years)	68,657	(29,104)	68,597	(24,774)
Regulatory assets	107,193	(12,508)	101,879	(9,501)
Other	32,544	—	41,466	—
Total intangibles and other assets	$ 555,055	$(121,884)	$ 489,992	$(105,883)

Aggregate amortization expense of intangible and other assets was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Reported in depreciation and amortization	$ 5,148	$ 4,983	$ 10,294	$ 9,692
Reported in interest expense	$ 2,165	$ 2,048	$ 4,330	$ 3,926

Estimated aggregate amortization expense for the next five years is as follows:

Years Ending December 31:	
2011	$26,915
2012	23,330
2013	17,899
2014	16,890
2015	14,566

7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value. Based on the estimated borrowing rates currently available to us and our subsidiaries for long-term loans with similar terms and average maturities, the aggregate fair value and carrying amount of long-term debt at June 30, 2010 was $6.55 billion and $6.09 billion, respectively. At December 31, 2009, the aggregate fair value and carrying amount of long-term debt was $6.75 billion and $6.22 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible “level” of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter (“OTC”) commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations.

The following tables summarize the fair value of our financial assets and liabilities measured and recorded at fair value on a recurring basis as of June 30, 2010 and December 31, 2009 based on inputs used to derive their fair values:

		Fair Value Measurements at June 30, 2010 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 3,002	$ 3,002	$ —
Interest rate derivatives	7,031	—	7,031
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	24	—	24
Swing Swaps IFERC	1,425	1,425	—
Fixed Swaps/Futures	1,045	1,045	—
Options – Puts	19,241	—	19,241
Total commodity derivatives	21,735	2,470	19,265
Total Assets	$ 31,768	$ 5,472	$ 26,296
Liabilities:			
Interest rate derivatives	$ (205)	$ —	$ (205)
Commodity derivatives:			
Natural Gas:			
Basic Swaps IFERC/NYMEX	(454)	(454)	—
Swing Swaps IFERC	(167)	—	(167)
Fixed Swaps/Futures	(181)	—	(181)
Options – Calls	(6,142)	—	(6,142)
Propane – Forwards/Swaps	(4,489)	—	(4,489)
Total commodity derivatives	(11,433)	(454)	(10,979)
Total Liabilities	$(11,638)	$ (454)	$(11,184)

		Fair Value Measurements at December 31, 2009 Using	
	Fair Value Total	Quoted Prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Observable Inputs (Level 2)
Assets:			
Marketable securities	$ 6,055	$ 6,055	$ —
Commodity derivatives	32,479	20,090	12,389
Liabilities:			
Commodity derivatives	(8,016)	(7,574)	(442)
Total	$30,518	$ 18,571	$ 11,947

In conjunction with the MEP Transaction, ETP adjusted the investment in MEP to fair value based on the present value of the expected future cash flows (Level 3), resulting in a nonrecurring fair value adjustment of $52.6 million. Substantially all of ETP's investment was transferred to ETE. See "Recent Developments" at Note 1.

8. INVESTMENTS IN AFFILIATES:

Midcontinent Express Pipeline, LLC

On May 26, 2010, ETP transferred to ETE, in exchange for ETP common units owned by ETE, substantially all of its interest in MEP. In conjunction with this transfer, ETP recorded a non-cash charge of approximately $52.6 million during the three months ending June 30, 2010 to reduce the carrying value of our interest to its estimated fair value. See discussion of the transaction in "Recent Developments" at Note 1.

Fayetteville Express Pipeline, LLC

ETP is party to an agreement with KMP for a 50/50 joint development of the Fayetteville Express pipeline, an approximately 185-mile natural gas pipeline that will originate in Conway County, Arkansas, continue eastward through White County, Arkansas and terminate at an interconnect with Trunkline Gas Company in Panola County, Mississippi. In December 2009, Fayetteville Express Pipeline LLC ("FEP"), the entity formed to construct, own and operate this pipeline, received Federal Energy Regulatory Commission ("FERC") approval of its application for authority to construct and operate this pipeline. The pipeline is expected to have an initial capacity of 2.0 Bcf/d and is expected to be in service by the end of 2010. As of June 30, 2010, FEP has secured binding commitments for a minimum of 10 years for transportation of approximately 1.85 Bcf/d. The new pipeline will interconnect with Natural Gas Pipeline Company of America ("NGPL") in White County, Arkansas, Texas Gas Transmission in Coahoma County, Mississippi and ANR Pipeline Company in Quitman County, Mississippi. NGPL is operated and partially owned by Kinder Morgan, Inc. Kinder Morgan, Inc. owns the general partner of KMP.

9. DEBT OBLIGATIONS:

Revolving Credit Facilities

ETP Credit Facility

ETP maintains a revolving credit facility (the "ETP Credit Facility") that provides for $2.0 billion of revolving credit capacity that is expandable to $3.0 billion (subject to obtaining the approval of the administrative agent and securing lender commitments for the increased borrowing capacity). The ETP Credit Facility matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating with a maximum fee of 0.125%. The fee is 0.11% based on our current rating.

As of June 30, 2010, there was $29.3 million of borrowings outstanding under the ETP Credit Facility. Taking into account letters of credit of approximately $21.8 million, the amount available for future borrowings was $1.95 billion. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 0.95%.

HOLP Credit Facility

HOLP has a $75.0 million Senior Revolving Facility (the "HOLP Credit Facility") available to HOLP through June 30, 2011, which may be expanded to $150.0 million. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the credit agreement for the HOLP Credit Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP and the capital stock of HOLP's subsidiaries secure the HOLP Credit Facility. At June 30, 2010, the HOLP credit facility had no outstanding balance in revolving credit loans and outstanding letters of credit of $0.5 million. The amount available for borrowing as of June 30, 2010 was $74.5 million.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our debt agreements at June 30, 2010.

10. MEMBER'S EQUITY:

Quarterly Distributions of Available Cash

The ETP LLC membership agreement contains specific provisions for the allocation of net earnings and losses to members for purposes of maintaining the partner capital accounts. The Board of the Company may distribute to the Member funds of the Company, which the Board reasonably determines are not needed for the payment of existing or foreseeable company obligations and expenditures.

Contributions to Subsidiary

In order to maintain our general partner interest in ETP, ETP GP has previously been required to make contributions to ETP each time ETP issues limited partner interests for cash or in connection with acquisitions. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP.

In July 2009, ETP amended and restated its partnership agreement, and as a result, ETP GP is no longer required to make corresponding contributions to maintain its general partner interest in ETP.

ETP GP paid off its contribution payable to ETP of $8.9 million during the three months ended March 31, 2010.

Quarterly Distributions of Available Cash

On February 15, 2010, ETP paid a cash distribution for the three months ended December 31, 2009 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on February 8, 2010.

On April 27, 2010, ETP paid a cash distribution for the three months ended March 31, 2010 of $0.89375 per Common Unit, or $3.575 annualized to Unitholders of record at the close of business on May 7, 2010.

On July 28, 2010, ETP declared a cash distribution for the three months ended June 30, 2010 of $0.89375 per Common Unit, or $3.575 annualized. This distribution will be paid on August 16, 2010 to Unitholders of record at close of business on August 9, 2010.

The total amounts of distributions ETP GP received from ETP relating to its general partner interests and incentive distribution rights of ETP are as follows (shown in the period with respect to which they relate):

	Six Months Ended June 30, 2010	2009
General Partner interest	$ 9,754	$ 9,720
Incentive Distribution Rights	184,751	168,311
Total distributions received from ETP	$ 194,505	$ 178,031

The total amounts of ETP distributions declared during the six months ended June 30, 2010 and 2009 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

	Six Months Ended June 30, 2010	2009
Limited Partners:		
Common Units	$ 332,371	$ 301,738
Class E Units	6,242	6,242
General Partner Interest	9,754	9,720
Incentive Distribution Rights	184,751	168,311
Total distributions declared by ETP	$ 533,118	$ 486,011

11. INCOME TAXES:

The components of the federal and state income tax expense (benefit) of our taxable subsidiaries are summarized as follows:

	Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Current expense (benefit):				
Federal	$ 1,599	$ (771)	$ 2,917	$ (5,107)
State	4,248	3,377	7,421	6,895
Total	5,847	2,606	10,338	1,788
Deferred expense (benefit):				
Federal	(997)	2,041	421	9,142
State	(281)	(88)	(266)	561
Total	(1,278)	1,953	155	9,703
Total income tax expense	$ 4,569	$ 4,559	$ 10,493	$ 11,491
Effective tax rate	9.64%	2.94%	3.58%	2.45%

The effective tax rate differs from the statutory rate due primarily to earnings that are not subject to federal and state income taxes at the Company level.

12. REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES:

Regulatory Matters

In August 2009, ETP filed an application for FERC authority to construct and operate the Tiger pipeline. The application was approved in April 2010 and construction began in June 2010. In February 2010, ETP announced a 400 MMcf/d expansion of the Tiger pipeline. In June 2010, ETP filed an application for FERC authority to construct, own and operate that expansion.

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (“NGA”) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Transwestern’s tariff rates and fuel rates are now final for the period of the settlement. Transwestern is required to file a new rate case no later than October 1, 2011.

Guarantees

MEP Guarantee

ETP has guaranteed 50% of the obligations of MEP under its senior revolving credit facility (the “MEP Facility”), with the remaining 50% of MEP Facility obligations guaranteed by KMP. Effective in May 2010, the commitment amount was reduced to $175.4 million due to lower usage and anticipated capital contributions. Although ETP transferred substantially all of its interest in MEP on May 26, 2010, as discussed above in “Recent Developments” at Note 1, ETP will continue to guarantee 50% of MEP’s obligations under this facility through the maturity of the facility in February 2011; however, Regency has agreed to indemnify ETP for any costs related to the guarantee of payments under this facility.

Subject to certain exceptions, ETP’s guarantee may be proportionately increased or decreased if its ownership percentage in MEP increases or decreases. The MEP Facility is unsecured and matures on February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP’s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets.

As of June 30, 2010, MEP had $33.1 million of outstanding borrowings and $33.3 million of letters of credit issued under the MEP Facility, respectively. ETP’s contingent obligations with respect to its 50% guarantee of MEP’s outstanding borrowings and letters of credit were $16.6 million and $16.6 million, respectively, as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 1.4%.

FEP Guarantee

On November 13, 2009, FEP entered into a credit agreement that provides for a $1.1 billion senior revolving credit facility (the “FEP Facility”). ETP has guaranteed 50% of the obligations of FEP under the FEP Facility, with the remaining 50% of FEP Facility obligations guaranteed by KMP. Subject to certain exceptions, ETP’s guarantee may be proportionately increased or decreased if ETP’s ownership percentage in FEP increases or decreases. The FEP Facility is available through May 11, 2012 and amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the FEP Facility varies based on both ETP’s credit rating and that of KMP, with a maximum fee of 1.0%.

As of June 30, 2010, FEP had $663.0 million of outstanding borrowings issued under the FEP Facility and ETP’s contingent obligation with respect to its 50% guarantee of FEP’s outstanding borrowings was $331.5 million as of June 30, 2010. The weighted average interest rate on the total amount outstanding as of June 30, 2010 was 3.2%.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts. In addition, we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We also have a contract to purchase not less than 90.0 million gallons of propane per year that expires in 2015. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.4 million and $5.5 million for the three months ended June 30, 2010 and 2009, respectively. For the six months ended June 30, 2010 and 2009, rental expense for operating leases totaled approximately $11.3 million and $11.5 million, respectively.

Our propane operations have an agreement with Enterprise GP Holdings L.P. ("Enterprise") (see Note 14) to supply a portion of our propane requirements. The agreement expired in March 2010 and our propane operations executed a five year extension as of April 2010. The extension will continue until March 2015 and includes an option to extend the agreement for an additional year.

We have commitments to make capital contributions to our joint ventures. For the joint ventures that we currently have interests in, we expect that capital contributions for the remainder of 2010 will be between $20 million and $30 million.

Litigation and Contingencies

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. Natural gas and propane are flammable, combustible gases. Serious personal injury and significant property damage can arise in connection with their transportation, storage or use. In the ordinary course of business, we are sometimes threatened with or named as a defendant in various lawsuits seeking actual and punitive damages for product liability, personal injury and property damage. We maintain liability insurance with insurers in amounts and with coverage and deductibles management believes are reasonable and prudent, and which are generally accepted in the industry. However, there can be no assurance that the levels of insurance protection currently in effect will continue to be available at reasonable prices or that such levels will remain adequate to protect us from material expenses related to product liability, personal injury or property damage in the future.

<u>FERC and Related Matters</u>. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the "Order and Notice") that contains allegations that we violated FERC rules and regulations. The FERC alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC alleged that during these periods we violated the FERC's then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the NGA. The FERC alleged that we violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. The FERC also alleged that one of our intrastate pipelines violated various FERC regulations by, among other things, granting undue preferences in favor of an affiliate. In its Order and Notice, the FERC also alleged that we manipulated daily prices at the Waha and Permian Hubs in West Texas on two dates. In its Order and Notice, the FERC specified that it was seeking $69.9 million in disgorgement of profits, plus interest, and $82.0 million in civil penalties relating to these market manipulation claims. In February 2008, the FERC's Enforcement Staff also recommended that the FERC pursue market manipulation claims related to ETP's trading activities in October 2005 for November 2005 monthly deliveries, a period not previously covered by the FERC's allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month.

On August 26, 2009, we entered into a settlement agreement with the FERC's Enforcement Staff with respect to the pending FERC claims against us and, on September 21, 2009, the FERC approved the settlement agreement without modification. The agreement resolves all outstanding FERC claims against us and provides that we make a $5.0 million payment to the federal government and establish a $25.0 million fund for the purpose of settling related third-party claims based on or arising out of the market manipulation allegation against us by those third parties that elect to make a claim against this fund, including existing litigation claims as well as any new claims that may be asserted against this fund. Pursuant to the settlement agreement, the FERC made no findings of fact or conclusions of law. In addition, the settlement agreement specifies that by executing the settlement agreement we do not admit or concede to the FERC or any third party any actual or potential fault, wrongdoing or liability in connection with our alleged conduct related to the FERC claims. The settlement agreement also requires us to maintain specified compliance programs and to conduct independent annual audits of such programs for a two-year period.

In September 2009, the FERC appointed an administrative law judge, or ALJ, to establish a process of potential claimants to make claims against the $25.0 million fund, to determine the validity of any such claims and to make a recommendation to the FERC relating to the application of this fund to any potential claimants. Pursuant to the process established by the ALJ, a number of parties submitted claims against this fund and, subsequent thereto, the ALJ made various determinations with respect to the validity of these claims and the methodology for making payments from the fund to claimants. In June 2010, each claimant that had been allocated a payment amount from the fund by the ALJ was required to make a determination as to whether to accept the ALJ's recommended payment amount from the fund, and all such claimants accepted their allocated payment amounts. In connection with accepting the allocated payment amount, each such claimant was required to waive and release all claims against ETP related to this matter. The claims of third parties that did not accept a payment from the fund are not affected by the ALJ's fund allocation process.

Taking into account the release of claims pursuant to the ALJ fund allocation process discussed above that were the subject of pending legal proceedings, ETP remains a party in three legal proceedings that assert contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages.

One of these legal proceedings involves a complaint filed in February 2008 by an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producer/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable, and the state court granted our motion for summary judgment on that issue. The Plaintiff appealed this determination to the First Court of Appeals, Houston, Texas. Both parties submitted briefs related to this appeal, and oral arguments related to this appeal were made before the First Court of Appeals on June 9, 2010. On June 24, 2010, the First Circuit Court of Appeals issued an opinion affirming the judgment of the lower court granting ETP's motion for summary judgment. No motion for rehearing was timely filed.

In October 2007, a consolidated class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the NYMEX in violation of the Commodity Exchange Act ("CEA"). It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions, and that we intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008, we filed a motion to dismiss the complaint. On March 26, 2009, the court issued an order dismissing the complaint, with prejudice, for failure to state a claim. On April 9, 2009, the plaintiffs moved for reconsideration of the order dismissing the complaint, and on August 26, 2009, the court denied the plaintiffs' motion for reconsideration. On September 24, 2009, the plaintiffs filed a Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit. Both parties submitted briefs related to the motion for reconsideration, and oral arguments on this motion were made before the Fifth Circuit on April 28, 2010. On June 23, 2010, the Fifth Circuit issued an opinion affirming the lower court's order dismissing the plaintiff's complaint. No petition for rehearing was timely filed.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint. On March 26, 2009, the court issued an order dismissing the complaint. The court found that the plaintiffs failed to state a claim on all causes of action and for anti-trust injury, but granted leave to amend. On April 23, 2009, the plaintiffs filed a motion for leave to amend to assert only one of the prior antitrust claims and to add a claim for common law fraud, and attached a proposed amended complaint as an exhibit. We opposed the motion and cross-moved to dismiss. On August 7, 2009, the court denied the plaintiff's motion and granted our motion to dismiss the complaint. On September 8, 2009, the plaintiff filed its Notice of Appeal with the U.S. Court of Appeals for the Fifth Circuit, appealing only the common law fraud claim. Both parties submitted briefs related to the judgment regarding the common law fraud claim, and oral arguments were made before the Fifth Circuit on April 27, 2010. We are awaiting a decision by the Fifth Circuit.

We are expensing the legal fees, consultants' fees and other expenses relating to these matters in the periods in which such costs are incurred. We record accruals for litigation and other contingencies whenever required by applicable accounting standards. Based on the terms of the settlement agreement with the FERC described above, we made the $5.0 million payment and established the $25.0 million fund in October 2009. We expect the after-tax cash impact of the settlement to be less than $30.0 million due to tax benefits resulting from the portion of the payment that is used to satisfy third party claims, which we expect to realize in future periods. Although this payment covers the $25.0 million required by the settlement agreement to be applied to resolve third party claims, including the existing third party litigation described above, it is possible that the amount we become obligated to pay to resolve third party litigation related to these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of the payment related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available to service our indebtedness either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations and our liquidity.

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the "HPL Entities"), their parent companies and American Electric Power Corporation ("AEP"), were defendants in litigation with Bank of America ("B of A") that related to AEP's acquisition of HPL in the Enron bankruptcy and B of A's financing of cushion gas stored in the Bammel storage facility ("Cushion Gas"). This litigation is referred to as the "Cushion Gas Litigation." In 2004, ETC OLP (a subsidiary of (ETP) acquired the HPL Entities from AEP, at which time AEP agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.00 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel storage facility. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP expects that it will be indemnified for any monetary damages awarded to B of A under to this court decision.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As of June 30, 2010 and December 31, 2009, accruals of approximately $11.4 million and $11.1 million, respectively, were recorded related to deductibles. As new information becomes available, our estimates may change. The impact of these changes may have a significant effect on our results of operations in a single period.

The outcome of these matters cannot be predicted with certainty and it is possible that the outcome of a particular matter will result in the payment of an amount in excess of the amount accrued for the matter. As our accrual amounts are non-cash, any cash payment of an amount in resolution of a particular matter would likely be made from cash from operations or borrowings. If cash payments to resolve a particular matter substantially exceed our accrual for such matter, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

No amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters and deductibles.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that can require expenditures to ensure compliance, including related to air emissions and wastewater discharges, at operating facilities and for remediation at current and former facilities as well as waste disposal sites. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in the natural gas pipeline, gathering, treating, compressing, bending and processing business. As a result, there can be no assurance that significant costs and liabilities will not be incurred. Costs of planning, designing, constructing and operating pipelines, plants and other facilities must incorporate compliance with environmental laws and regulations and safety standards. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the issuance of injunctions and the filing of federally authorized citizen suits. Moreover, it is possible that other developments, such as increasingly stringent environmental laws, regulations and enforcement policies thereunder, and claims for damages to property or persons resulting from the operations, could result in substantial costs and liabilities. Accordingly, we have adopted policies, practices and procedures in the areas of pollution control, product safety, occupational safety and health, and the handling, storage, use, and disposal of hazardous materials to prevent and minimize material environmental or other damage, and to limit the financial liability, which could result from such events. However, the risk of environmental or other damage is inherent in transporting, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products, as it is with other entities engaged in similar businesses.

Environmental exposures and liabilities are difficult to assess and estimate due to unknown factors such as the magnitude of possible contamination, the timing and extent of remediation, the determination of our liability in proportion to other parties, improvements in clean-up technologies and the extent to which environmental laws and regulations may change in the future. Although environmental costs may have a significant impact on the results of operations for any single period, we believe that such costs will not have a material adverse effect on our financial position.

As of June 30, 2010 and December 31, 2009, accruals on an undiscounted basis of $12.5 million and $12.6 million, respectively, were recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities.

Based on information available at this time and reviews undertaken to identify potential exposure, we believe the amount reserved for environmental matters is adequate to cover the potential exposure for clean-up costs.

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean-up activities include remediation of several compressor sites on the Transwestern system for historical contamination associated with polychlorinated biphenyls (“PCBs”) and the costs of this work are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue through 2018 is $8.5 million, which is included in the aggregate environmental accruals. Transwestern received FERC approval for rate recovery of projected soil and groundwater remediation costs not related to PCBs effective April 1, 2007.

Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing potential PCBs. Future costs cannot be reasonably estimated because remediation activities are undertaken as potential claims are made by customers and former customers. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

Environmental regulations were recently modified for the U.S. Environmental Protection Agency’s (the “EPA”) Spill Prevention, Control and Countermeasures (“SPCC”) program. We are currently reviewing the impact to our operations and expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures. Costs associated with tank integrity testing and resulting corrective actions cannot be reasonably estimated at this time, but we believe such costs will not have a material adverse effect on our financial position, results of operations or cash flows.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our June 30, 2010 or December 31, 2009 consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

By March 2013, the Texas Commission on Environmental Quality is required to develop another plan to address the recent change in the ozone standard from 0.08 parts per million, or ppm, to 0.075 ppm and the U.S Environmental Protection Agency, or EPA, recently proposed lowering the standard even further, to somewhere in between 0.06 and 0.07 ppm. These efforts may result in the adoption of new regulations that may require additional nitrogen oxide emissions reductions.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT") under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended June 30, 2010 and 2009, $3.6 million and $11.6 million, respectively, of capital costs and $4.4 million and $5.6 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the six months ended June 30, 2010 and 2009, $5.0 million and $15.3 million, respectively, of capital costs and $6.3 million and $9.0 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

Our operations are also subject to the requirements of the federal Occupational Safety and Health Act, also known as OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

National Fire Protection Association Pamphlets No. 54 and No. 58, which establish rules and procedures governing the safe handling of propane, or comparable regulations, have been adopted as the industry standard in all of the states in which we operate. In some states, these laws are administered by state agencies, and in others, they are administered on a municipal level. With respect to the transportation of propane by truck, we are subject to regulations governing the transportation of hazardous materials under the Federal Motor Carrier Safety Act, administered by the DOT. We conduct ongoing training programs to help ensure that our operations are in compliance with applicable regulations. We believe that the procedures currently in effect at all of our facilities for the handling, storage and distribution of propane are consistent with industry standards and are in substantial compliance with applicable laws and regulations.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets. In general, we use derivatives to eliminate market exposure and price risk within our operations as follows:

- Derivatives are utilized in our midstream operations in order to mitigate price volatility in our marketing activities and manage fixed price exposure incurred from contractual obligations.

- We use derivative financial instruments in connection with our natural gas inventory at the Bammel storage facility by purchasing physical natural gas and then selling financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. We also use derivatives in our intrastate transportation and storage and interstate operations to hedge the sales price of retention and operational gas sales and hedge location price differentials related to the transportation of natural gas.
- Our propane operations permit customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, when the price of natural gas is higher in the future than the current spot price. We use financial derivatives to hedge the natural gas held in connection with these arbitrage opportunities. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market or off peak season and entering a financial contract to lock in the sale price. If we designate the related financial contract as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices along with the financial derivative we use to hedge it. Changes in the spread between the forward natural gas prices designated as fair value hedges and the physical inventory spot price result in unrealized gains or losses until the underlying physical gas is withdrawn and the related designated derivatives are settled. Once the gas is withdrawn and the designated derivatives are settled, the previously unrealized gains or losses associated with these positions are realized. Unrealized margins represent the unrealized gains or losses from our derivative instruments using mark to market accounting, with changes in the fair value of our derivatives being recorded directly in earnings. These margins fluctuate based upon changes in the spreads between the physical spot price and forward natural gas prices. If the spread narrows between the physical and financial prices, we will record unrealized gains or lower unrealized losses. If the spread widens, we will record unrealized losses or lower unrealized gains. Typically, as we enter the winter months, the spread converges so that we recognize in earnings the original locked-in spread, through either mark-to-market or the physical withdrawal of natural gas.

The recent adoption of comprehensive financial reform legislation by the United States Congress could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business. See Part II, Item 1A. Risk Factors of this Form 10-Q.

We are also exposed to market risk on gas we retain for fees in our intrastate transportation and storage operations and operational gas sales on our interstate transportation operations. We use financial derivatives to hedge the sales price of this gas, including futures, swaps and options. For certain contracts that qualify for hedge accounting, we designate them as cash flow hedges of the forecasted sale of gas. The change in value, to the extent the contracts are effective, remains in accumulated other comprehensive income until the forecasted transaction occurs. When the forecasted transaction occurs, any gain or loss associated with the derivative is recorded in cost of products sold in the consolidated statement of operations.

We attempt to maintain balanced positions in our marketing activities to protect ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist. Long-term physical contracts are tied to index prices. System gas, which is also tied to index prices, is expected to provide most of the gas required by our long-term physical contracts. When third-party gas is required to supply long-term contracts, a hedge is put in place to protect the margin on the contract. Financial contracts, which are not tied to physical delivery, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist, fluctuating commodity prices can impact our financial position and results of operations, either favorably or unfavorably.

The following table details the outstanding commodity-related derivatives:

	June 30, 2010		December 31, 2009	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark to Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(23,182,500)	2010-2011	72,325,000	2010-2011
Swing Swaps IFERC (MMBtu)	(23,592,500)	2010-2011	(38,935,000)	2010
Fixed Swaps/Futures (MMBtu)	(395,000)	2010-2011	4,852,500	2010-2011
Options – Puts (MMBtu)	(8,140,000)	2010-2011	2,640,000	2010
Options – Calls (MMBtu)	(5,920,000)	2010-2011	(2,640,000)	2010
Propane:				
Forwards/Swaps (Gallons)	—	—	6,090,000	2010
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(5,410,000)	2010-2011	(22,625,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,765,000)	2010-2011	(27,300,000)	2010
Hedged Item – Inventory (MMBtu)	18,765,000	2010	27,300,000	2010
Cash Flow Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(10,845,000)	2010-2011	(13,225,000)	2010
Fixed Swaps/Futures (MMBtu)	(18,502,500)	2010-2011	(22,800,000)	2010
Options – Puts (MMBtu)	25,800,000	2011-2012	—	—
Options – Calls (MMBtu)	(25,800,000)	2011-2012	—	—
Propane:				
Forwards/Swaps (Gallons)	51,702,000	2010-2011	20,538,000	2010

We expect gains of $11.0 million related to commodity derivatives to be reclassified into earnings over the next year related to amounts currently reported in AOCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

Interest Rate Risk

We are exposed to market risk for changes in interest rates. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage a portion of our current and future interest rate exposures by utilizing interest rate swaps in order to achieve our desired mix of fixed and variable rate debt. We also utilize interest rate swaps to lock in the rate on a portion of our anticipated debt issuances. We have the following interest rate swaps outstanding as of June 30, 2010:

Term	Notional Amount	Type [1]	Hedge Designation
July 2013	$350,000	Pay a floating rate plus 3.75% and receive a fixed rate of 6.00%	Fair value
August 2012	200,000	Forward starting to pay a fixed rate of 3.80% and receive a floating rate	Cash flow

(1) Floating rates are based on LIBOR.

In May 2010, ETP terminated interest rate swaps with notional amounts of $750.0 million that were designated as fair value hedges. Proceeds from the swap termination were $15.4 million. In connection with the swap termination, $9.7 million of previously recorded fair value adjustments to the hedged long-term debt will be amortized as a reduction of interest expense through February 2015.

Derivative Summary

The following table provides a balance sheet overview of ETP's derivative assets and liabilities as of June 30, 2010 and December 31, 2009:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	June 30, 2010	December 31, 2009	June 30, 2010	December 31, 2009
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$25,158	$ 669	$ (4,425)	$ (24,035)
Commodity derivatives	—	8,443	(4,625)	(201)
Interest rate derivatives	7,031	—	(205)	—
	32,189	9,112	(9,255)	(24,236)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	32,257	72,851	(37,877)	(36,950)
Commodity derivatives	24	3,928	(212)	(241)
	32,281	76,779	(38,089)	(37,191)
Total derivatives	$64,470	$ 85,891	$(47,344)	$ (61,427)

The commodity derivatives (margin deposits) are recorded in "Other current assets" on our condensed consolidated balance sheets. The remainder of the derivatives are recorded in "Price risk management assets/liabilities."

We disclose the non-exchange traded financial derivative instruments as price risk management assets and liabilities on our condensed consolidated balance sheets at fair value with amounts classified as either current or long-term depending on the anticipated settlement date.

We utilize master-netting agreements and have maintenance margin deposits with certain counterparties in the OTC market and with clearing brokers. Payments on margin deposits are required when the value of a derivative exceeds our pre-established credit limit with the counterparty. Margin deposits are returned to us on the settlement date for non-exchange traded derivatives, and we exchange margin calls on a daily basis for exchange traded transactions. Since the margin calls are made daily with the exchange brokers, the fair value of the financial derivative instruments are deemed current and netted in deposits paid to vendors within other current assets in the condensed consolidated balance sheets. ETP had net deposits with counterparties of $44.4 million and $79.7 million as of June 30, 2010 and December 31, 2009, respectively.

The following tables detail the effect of ETP's derivative assets and liabilities in the condensed consolidated statements of operations for the periods presented:

	Change in Value Recognized in OCI on Derivatives (Effective Portion)			
	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$(9,150)	$1,336	$24,957	$ (50)
Interest rate derivatives	(205)	—	(205)	—
Total	$(9,355)	$1,336	$24,752	$ (50)

	Location of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ 7,058	$ (928)	$12,373	$ 9,549
Interest rate derivatives	Interest expense	71	72	142	144
Total		$ 7,129	$ (856)	$12,515	$ 9,693

	Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion)	Amount of Gain (Loss) Recognized in Income on Ineffective Portion			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$ (1,016)	$ —	$ 105	$ —
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ (1,016)	$ —	$ 105	$ —

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income representing hedge ineffectiveness and amount excluded from the assessment of effectiveness			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$ 6,417	$12,498	$ (967)	$ 12,498
Interest rate derivatives	Interest expense	—	—	—	—
Total		$ 6,417	$12,498	$ (967)	$ 12,498

	Location of Gain/(Loss) Recognized in Income on Derivatives	Amount of Gain (Loss) Recognized in Income on Derivatives			
		Three Months Ended June 30,		Six Months Ended June 30,	
		2010	2009	2010	2009
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$(21,295)	$ 5,138	$ 672	$ 56,576
Interest rate derivatives	Gains (losses) on non-hedged interest rate derivatives	—	36,842	—	50,568
Total		$(21,295)	$41,980	$ 672	$107,144

We recognized $36.5 million and $27.0 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended June 30, 2010 and 2009, respectively. We recognized $45.2 million and $46.1 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the six months ended June 30, 2010 and 2009, respectively.

Credit Risk

We maintain credit policies with regard to our counterparties that we believe minimize our overall credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit ratings), collateral requirements under certain circumstances and the use of standardized agreements, which allow for netting of positive and negative exposure associated with a single counterparty.

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact its overall exposure to credit risk, either positively or negatively in that the counterparties may be similarly affected by changes in economic, regulatory or other conditions. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty performance.

For financial instruments, failure of a counterparty to perform on a contract could result in our inability to realize amounts that have been recorded on our condensed consolidated balance sheet and recognized in net income or other comprehensive income.

14. RELATED PARTY TRANSACTIONS:

As discussed in "Recent Developments" in Note 1, Regency became a related party on May 26, 2010. Regency provides us with contract compression services. For the period from May 26, 2010 to June 30, 2010, we recorded costs of products sold of $0.7 million and operating expenses of $0.2 million related to transactions with Regency.

We and subsidiaries of Enterprise transport natural gas on each other's pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. The following table presents sales to and purchase from affiliates of Enterprise:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Natural Gas Operations:				
Sales	$ 130,526	$ 90,591	$ 275,246	$ 165,074
Purchases	6,936	2,688	13,533	16,346
Propane Operations:				
Sales	481	5,226	10,966	11,508
Purchases	52,415	41,005	218,179	176,223

Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that was extended until March 2015, and includes an option to extend the agreement for an additional year. As of December 31, 2009, Titan had forward mark-to-market derivatives for approximately 6.1 million gallons of propane at a fair value asset of $3.3 million with Enterprise. All of these forward contracts were settled as of June 30, 2010. In addition, as of June 30, 2010 and December 31, 2009, Titan had forward derivatives accounted for as cash flow hedges of 51.7 million and 20.5 million gallons of propane at a fair value liability of $4.5 million and a fair value asset of $8.4 million, respectively, with Enterprise.

The following table summarizes the related party balances on our condensed consolidated balance sheets:

	June 30, 2010	December 31, 2009
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$41,451	$ 47,005
Propane Operations	181	3,386
Other	7,730	6,757
Total accounts receivable from related parties:	$49,362	$ 57,148
Accounts payable from related parties:		
Enterprise:		
Natural Gas Operations	$ 825	$ 3,518
Propane Operations	5,478	31,642
Other	1,320	3,682
Total accounts payable from related parties:	$ 7,623	$ 38,842

The net imbalance payable from Enterprise was $1.9 million and $0.7 million for June 30, 2010 and December 31, 2009, respectively.

15. OTHER INFORMATION:

The tables below present additional detail for certain balance sheet captions.

Other Current Assets

Other current assets consisted of the following:

	June 30, 2010	December 31, 2009
Deposits paid to vendors	$44,393	$ 79,694
Prepaid and other	46,768	68,729
Total other current assets	$91,161	$ 148,423

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

	June 30, 2010	December 31, 2009
Interest payable	$133,314	$ 136,229
Customer advances and deposits	69,591	88,430
Accrued capital expenditures	73,432	46,134
Accrued wages and benefits	40,272	25,202
Taxes other than income taxes	72,041	23,294
Income taxes payable	9,811	3,401
Deferred income taxes	109	—
Other	60,576	42,485
Total accrued and other current liabilities	$459,146	$ 365,175

16. SUPPLEMENTAL INFORMATION:

Following are the financial statements of the Company, which are included to provide additional information with respect to the Company's financial position, results of operations and cash flows on a stand-alone basis:

BALANCE SHEETS
(Dollars in thousands)
(unaudited)

	June 30, 2010	December 31, 2009
ASSETS:		
Investment in affiliates	$ 18	$ 18
EQUITY:		
Member's Equity	$ 18	$ 18

STATEMENTS OF OPERATIONS
(Dollars in thousands)
(unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Equity in earnings of affiliates	$ 10	$ 9	$ 19	$ 18
NET INCOME	$ 10	$ 9	$ 19	$ 18

STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

	Six Months Ended June 30,	
	2010	2009
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 19	$ 17
CASH FLOWS FROM FINANCING ACTIVITIES:		
Distributions to member	(19)	(17)
Net cash used in financing activities	(19)	(17)
INCREASE IN CASH AND CASH EQUIVALENTS	—	—
CASH AND CASH EQUIVALENTS, beginning of period	—	—
CASH AND CASH EQUIVALENTS, end of period	$ —	$ —

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners
Regency Energy Partners LP:

We have audited the accompanying consolidated balance sheets of Regency Energy Partners LP and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency Energy Partners LP and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Regency Energy Partners LP's internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2010 expressed an unqualified opinion on the effectiveness of the Partnership's internal control over financial reporting.

/s/ KPMG LLP

Dallas, Texas
March 1, 2010

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners
Regency Energy Partners LP:

We have audited Regency Energy Partners LP and subsidiaries' internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Regency Energy Partners LP's management is responsible 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 Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

In our opinion, Regency Energy Partners LP and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Regency Energy Partners LP and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009, and our report dated March 1, 2010 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Dallas, Texas
March 1, 2010

Regency Energy Partners LP

Consolidated Balance Sheets
(in thousands except unit data)

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,827	$ 599
Restricted cash	1,511	10,031
Trade accounts receivable, net of allowance of $1,130 and $941	30,433	40,875
Accrued revenues	95,240	96,712
Related party receivables	6,222	855
Derivative assets	24,987	73,993
Other current assets	10,556	13,338
Total current assets	178,776	236,403
Property, Plant and Equipment:		
Gathering and transmission systems	465,959	652,267
Compression equipment	823,060	799,527
Gas plants and buildings	159,596	156,246
Other property, plant and equipment	162,433	167,256
Construction-in-progress	95,547	154,852
Total property, plant and equipment	1,706,595	1,930,148
Less accumulated depreciation	(250,160)	(226,594)
Property, plant and equipment, net	1,456,435	1,703,554
Other Assets:		
Investment in unconsolidated subsidiary	453,120	—
Long-term derivative assets	207	36,798
Other, net of accumulated amortization of debt issuance costs of $10,743 and $5,246	19,468	13,880
Total other assets	472,795	50,678
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $33,929 and $22,517	197,294	205,646
Goodwill	228,114	262,358
Total intangible assets and goodwill	425,408	468,004
TOTAL ASSETS	$ 2,533,414	$ 2,458,639
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 44,912	$ 65,483
Accrued cost of gas and liquids	76,657	76,599
Related party payables	2,312	—
Deferred revenue, including related party amounts of $338 and $0	11,292	11,572
Derivative liabilities	12,256	42,691
Escrow payable	1,511	10,031
Other current liabilities	12,368	10,574
Total current liabilities	161,308	216,950
Long-term derivative liabilities	48,903	560
Other long-term liabilities	14,183	15,487
Long-term debt, net	1,014,299	1,126,229
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount $83,891	51,711	—
Partners' Capital and Noncontrolling Interest:		
Common units (94,243,886 and 55,519,903 units authorized; 93,188,353 and 54,796,701 units issued and outstanding at December 31, 2009 and 2008)	1,211,605	764,161
Class D common units (7,276,506 units authorized, issued and outstanding at December 31, 2008)	—	226,759
Subordinated units (19,103,896 units authorized, issued and outstanding at December 31, 2008)	—	(1,391)
General partner interest	19,249	29,283
Accumulated other comprehensive (loss) income	(1,994)	67,440
Noncontrolling interest	14,150	13,161
Total partners' capital and noncontrolling interest	1,243,010	1,099,413
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 2,533,414	$ 2,458,639

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Operations
(in thousands except unit data and per unit data)

	Year Ended December 31,		
	2009	2008	2007
REVENUES			
Gas sales	$ 481,400	$ 1,126,760	$ 744,681
NGL sales	262,652	409,476	347,737
Gathering, transportation and other fees, including related party amounts of $11,162, $3,763 and $1,350	273,770	286,507	100,644
Net realized and unrealized gain (loss) from derivatives	41,577	(21,233)	(34,266)
Other	30,098	62,294	31,442
Total revenues	1,089,497	1,863,804	1,190,238
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $10,913, $1,878 and $14,165 and excluding items shown separately below	699,563	1,408,333	976,145
Operation and maintenance	130,826	131,629	58,000
General and administrative	57,863	51,323	39,713
Loss (gain) on asset sales, net	(133,284)	472	1,522
Management services termination fee	—	3,888	—
Transaction expenses	—	1,620	420
Depreciation and amortization	109,893	102,566	55,074
Total operating costs and expenses	864,861	1,699,831	1,130,874
OPERATING INCOME	224,636	163,973	59,364
Income from unconsolidated subsidiary	7,886	—	—
Interest expense, net	(77,996)	(63,243)	(52,016)
Loss on debt refinancing	—	—	(21,200)
Other income and deductions, net	(15,132)	332	1,252
INCOME (LOSS) BEFORE INCOME TAXES	139,394	101,062	(12,600)
Income tax (benefit) expense	(1,095)	(266)	931
NET INCOME (LOSS)	$ 140,489	$ 101,328	$ (13,531)
Net income attributable to noncontrolling interest	(91)	(312)	(305)
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ 140,398	$ 101,016	$ (13,836)
Amounts attributable to Series A convertible redeemable preferred units	3,995	—	—
General partner's interest, including IDR	5,252	4,303	(366)
Amount allocated to non-vested common units	965	869	(103)
Beneficial conversion feature for Class D common units	820	7,199	—
Beneficial conversion feature for Class C common units	—	—	1,385
Amount allocated to Class E common units	—	—	5,792
Limited partners' interest	$ 129,366	$ 88,645	$ (20,544)
Basic and Diluted earnings (loss) per unit:			
Amount allocated to common and subordinated units	$ 129,366	$ 88,645	$ (20,544)
Weighted average number of common and subordinated units outstanding	80,582,705	66,190,626	51,056,769
Basic income (loss) per common and subordinated unit	$ 1.61	$ 1.34	$ (0.40)
Diluted income (loss) per common and subordinated unit	$ 1.60	$ 1.28	$ (0.40)
Distributions paid per unit	$ 1.78	$ 1.71	$ 1.52
Amount allocated to Class B common units	$ —	$ —	$ —
Weighted average number of Class B common units outstanding	—	—	651,964
Income per Class B common unit	$ —	$ —	$ —
Distributions per unit	$ —	$ —	$ —
Amount allocated to Class C common units	$ —	$ —	$ 1,385
Total number of Class C common units outstanding	—	—	2,857,143
Income per Class C common unit due to beneficial conversion feature	$ —	$ —	$ 0.48
Distributions per unit	$ —	$ —	$ —
Amount allocated to Class D common units	$ 820	$ 7,199	$ —
Total number of Class D common units outstanding	7,276,506	7,276,506	—
Income per Class D common unit due to beneficial conversion feature	$ 0.11	$ 0.99	$ —
Distributions per unit	$ —	$ —	$ —
Amount allocated to Class E common units	$ —	$ —	$ 5,792
Total number of Class E common units outstanding	—	—	4,701,034
Income per Class E common unit due to beneficial conversion feature	$ —	$ —	$ 1.23
Distributions per unit	$ —	$ —	$ 2.06

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$140,489	$101,328	$(13,531)
Net hedging amounts reclassified to earnings	(47,394)	35,512	19,362
Net change in fair value of cash flow hedges	(22,040)	70,253	(58,706)
Comprehensive income (loss)	$ 71,055	$207,093	$(52,875)
Comprehensive income attributable to noncontrolling interest	91	312	305
Comprehensive income (loss) attributable to Regency Energy Partners LP	$ 70,964	$206,781	$(53,180)

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Cash Flows
(in thousands)

	Year Ended December 31,		
	2009	2008	2007
OPERATING ACTIVITIES			
Net income	$ 140,489	$ 101,328	$ (13,531)
Adjustments to reconcile net income to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization	116,307	105,324	57,069
Write-off of debt issuance costs	—	—	5,078
Non-cash income from unconsolidated subsidiary	—	—	(43)
Derivative valuation changes	5,163	(14,700)	14,667
Loss (gain) on asset sales, net	(133,284)	472	1,522
Unit based compensation expenses	6,008	4,306	15,534
Gain on insurance settlements	—	(3,282)	—
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues, and related party receivables	10,727	18,648	(28,789)
Other current assets	10,471	(6,615)	(1,394)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(3,762)	(40,772)	30,089
Other current liabilities	(6,726)	12,749	(149)
Amount of swap termination proceeds reclassified into earnings	—	—	(1,078)
Other assets and liabilities	(1,433)	3,840	554
Net cash flows provided by operating activities	143,960	181,298	79,529
INVESTING ACTIVITIES			
Capital expenditures	(193,083)	(375,083)	(129,784)
Acquisitions	(52,803)	(577,668)	(34,855)
Return of investment in unconsolidated subsidiary	1,039	—	—
Acquisition of investment in unconsolidated subsidiary, net of $100 cash	—	—	(5,000)
Net proceeds from asset sales	88,682	840	11,706
Proceeds from insurance settlement	—	3,282	—
Net cash flows used in investing activities	(156,165)	(948,629)	(157,933)
FINANCING ACTIVITIES			
Net (repayments) borrowings under revolving credit facilities	(349,087)	644,729	59,300
Repayments under credit facilities	—	—	(50,000)
Proceeds from issuance (repayments) of senior notes, net of discount	236,240	—	(192,500)
Debt issuance costs	(12,224)	(2,940)	(2,427)
Partner contributions	6,344	11,746	7,735
Partner distributions	(146,585)	(120,591)	(79,933)
Acquisition of assets between entities under common control in excess of historical cost	(10,197)	—	—
Proceeds from option exercises	—	2,700	—
Proceeds from equity issuances, net of issuance costs	220,318	199,315	353,546
Proceeds from preferred equity issuance, net of issuance costs	76,624	—	—
FrontStreet distributions	—	—	(9,695)
FrontStreet contributions	—	—	13,417
Net cash flows provided by financing activities	21,433	734,959	99,443
Net increase (decrease) in cash and cash equivalents	9,228	(32,372)	21,039
Cash and cash equivalents at beginning of period	599	32,971	9,139
Cash acquired from FrontStreet	—	—	2,793
Cash and cash equivalents at end of period	$ 9,827	$ 599	$ 32,971
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 69,401	$ 59,969	$ 67,844
Income taxes paid	6	605	—
Non-cash capital expenditures in accounts payable	9,688	25,845	7,761
Non-cash capital expenditure for consolidation of investment in previously unconsolidated subsidiary	—	—	5,650
Non-cash capital expenditure upon entering into a capital lease obligation	—	—	3,000
Issuance of common units for an acquisition	—	219,560	19,724
Release of escrow payable from restricted cash	8,501	4,570	—
Contribution of fixed assets, goodwill and working capital to HPC	263,921	—	—
Non-cash proceeds from contribution of RIGS to HPC	403,568	—	—
Distributions accrued but not paid to Series A convertible redeemable preferred units	3,891	—	—

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in thousands except unit data)

	Units						Common	Class B
	Common	Class B	Class C	Class D	Class E	Subordinated	Unitholders	Unitholders
Balance—December 31, 2006	19,620,396	5,173,189	2,857,143	—	—	19,103,896	$ 42,192	$ 60,671
Conversion of Class B and C to common units	8,030,332	(5,173,189)	(2,857,143)	—	—	—	120,663	(60,671)
Issuance of common units for acquisition	751,597	—	—	—	—	—	19,724	—
Issuance of common units	11,500,000	—	—	—	—	—	353,446	—
Issuance of restricted common units, net of forfeitures	565,167	—	—	—	—	—	—	—
Exercise of common unit options	47,403	—	—	—	—	—	100	—
Unit based compensation expenses	—	—	—	—	—	—	15,534	—
Partner distributions	—	—	—	—	—	—	(49,296)	—
Partner contributions	—	—	—	—	—	—	—	—
Acquisition of FrontStreet	—	—	—	—	4,701,034	—	—	—
FrontStreet contributions	—	—	—	—	—	—	—	—
FrontStreet distributions	—	—	—	—	—	—	—	—
Contributions from noncontrolling interest	—	—	—	—	—	—	—	—
Net (loss) income	—	—	—	—	—	—	(12,037)	—
Other	—	—	—	—	—	—	25	—
Net hedging activity reclassified to earnings	—	—	—	—	—	—	—	—
Net change in fair value of cash flow hedges	—	—	—	—	—	—	—	—
Balance—December 31, 2007	40,514,895	—	—	—	4,701,034	19,103,896	490,351	—
Issuance of Class D common units	—	—	—	7,276,506	—	—	—	—
Issuance of restricted common units and option exercises, net of forfeitures	559,863	—	—	—	—	—	2,700	—
Issuance of common units	9,020,909	—	—	—	—	—	199,315	—
Working capital adjustment on FrontStreet	—	—	—	—	—	—	—	—
Acquisition on noncontrolling interest	—	—	—	—	—	—	—	—
Conversion of Class E common units	4,701,034	—	—	—	(4,701,034)	—	92,104	—
Unit based compensation expenses	—	—	—	—	—	—	4,306	—
Partner distributions	—	—	—	—	—	—	(84,207)	—
Partner contributions	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	59,592	—
Contributions from noncontrolling interest	—	—	—	—	—	—	—	—
Net hedging amounts reclassified to earnings	—	—	—	—	—	—	—	—
Net change in fair value of cash flow hedges	—	—	—	—	—	—	—	—
Balance—December 31, 2008	54,796,701	—	—	7,276,506	—	19,103,896	764,161	—
Revision of partner interest	—	—	—	—	—	—	6,073	—
Issuance of restricted common units, net of forfeitures	(63,750)	—	—	—	—	—	—	—
Issuance of common units	12,075,000	—	—	—	—	—	220,318	—
Conversion of subordinated units	19,103,896	—	—	—	—	(19,103,896)	(1,391)	—
Unit based compensation expenses	—	—	—	—	—	—	6,008	—
Accrued distributions to phantom units	—	—	—	—	—	—	(249)	—
Acquisition of assets between entities under common control in excess of historical cost	—	—	—	—	—	—	—	—
Partner distributions	—	—	—	—	—	—	(141,225)	—
Partner contributions	—	—	—	—	—	—	—	—
Net income	—	—	—	—	—	—	134,326	—
Conversion of Class D common units	7,276,506	—	—	(7,276,506)	—	—	227,579	—
Contributions from noncontrolling interest	—	—	—	—	—	—	—	—
Accrued distributions to Series A convertible redeemable preferred units	—	—	—	—	—	—	(3,891)	—
Accretion of Series A convertible redeemable preferred units	—	—	—	—	—	—	(104)	—
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	—	—	—	—
Net change in fair value of cash flow hedges	—	—	—	—	—	—	—	—
Balance—December 31, 2009	93,188,353	—	—	—	—	—	$ 1,211,605	$ —

See accompanying notes to consolidated financial statements

Regency Energy Partners LP

Consolidated Statements of Partners' Capital and Noncontrolling Interest—(Continued)
(in thousands except unit data)

	Class C Unitholders	Class D Unitholders	Class E Unitholders	Subordinated Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance—December 31, 2006	$ 59,992	$ —	$ —	$ 43,240	$ 5,543	$ 1,019	$ —	$ 212,657
Conversion of Class B and C to common units	(59,992)	—	—	—	—	—	—	—
Issuance of common units for acquisition	—	—	—	—	—	—	—	19,724
Issuance of common units	—	—	—	—	—	—	—	353,446
Issuance of restricted common units, net of forfeitures	—	—	—	—	—	—	—	—
Exercise of common unit options	—	—	—	—	—	—	—	100
Unit based compensation expenses	—	—	—	—	—	—	—	15,534
Partner distributions	—	—	—	(29,038)	(1,599)	—	—	(79,933)
Partner contributions	—	—	—	—	7,735	—	—	7,735
Acquisition of FrontStreet	—	—	83,448	—	—	—	—	83,448
FrontStreet contributions	—	—	13,417	—	—	—	—	13,417
FrontStreet distributions	—	—	(9,695)	—	—	—	—	(9,695)
Contributions from noncontrolling interest	—	—	—	—	—	—	4,588	4,588
Net (loss) income	—	—	5,792	(7,198)	(393)	—	305	(13,531)
Other	—	—	—	15	—	—	—	40
Net hedging activity reclassified to earnings	—	—	—	—	—	19,362	—	19,362
Net change in fair value of cash flow hedges	—	—	—	—	—	(58,706)	—	(58,706)
Balance—December 31, 2007	—	—	92,962	7,019	11,286	(38,325)	4,893	568,186
Issuance of Class D common units	—	219,560	—	—	—	—	—	219,560
Issuance of restricted common units and option exercises, net of forfeitures	—	—	—	—	—	—	—	2,700
Issuance of common units	—	—	—	—	—	—	—	199,315
Working capital adjustment on FrontStreet	—	—	(858)	—	—	—	—	(858)
Acquisition on noncontrolling interest	—	—	—	—	—	—	(4,893)	(4,893)
Conversion of Class E common units	—	—	(92,104)	—	—	—	—	—
Unit based compensation expenses	—	—	—	—	—	—	—	4,306
Partner distributions	—	—	—	(32,668)	(3,716)	—	—	(120,591)
Partner contributions	—	—	—	—	11,746	—	—	11,746
Net income	—	7,199	—	24,258	9,967	—	312	101,328
Contributions from noncontrolling interest	—	—	—	—	—	—	12,849	12,849
Net hedging amounts reclassified to earnings	—	—	—	—	—	35,512	—	35,512
Net change in fair value of cash flow hedges	—	—	—	—	—	70,253	—	70,253
Balance—December 31, 2008	—	226,759	—	(1,391)	29,283	67,440	13,161	1,099,413
Revision of partner interest	—	—	—	—	(6,073)	—	—	—
Issuance of restricted common units, net of forfeitures	—	—	—	—	—	—	—	—
Issuance of common units	—	—	—	—	—	—	—	220,318
Conversion of subordinated units	—	—	—	1,391	—	—	—	—
Unit based compensation expenses	—	—	—	—	—	—	—	6,008
Accrued distributions to phantom units	—	—	—	—	—	—	—	(249)
Acquisition of assets between entities under common control in excess of historical cost	—	—	—	—	(10,197)	—	—	(10,197)
Partner distributions	—	—	—	—	(5,360)	—	—	(146,585)
Partner contributions	—	—	—	—	6,344	—	—	6,344
Net income	—	820	—	—	5,252	—	91	140,489
Conversion of Class D common units	—	(227,579)	—	—	—	—	—	—
Contributions from noncontrolling interest	—	—	—	—	—	—	898	898
Accrued distributions to Series A convertible redeemable preferred units	—	—	—	—	—	—	—	(3,891)
Accretion of Series A convertible redeemable preferred units	—	—	—	—	—	—	—	(104)
Net cash flow hedge amounts reclassified to earnings	—	—	—	—	—	(47,394)	—	(47,394)
Net change in fair value of cash flow hedges	—	—	—	—	—	(22,040)	—	(22,040)
Balance—December 31, 2009	$ —	$ —	$ —	$ —	$ 19,249	$ (1,994)	$ 14,150	$1,243,010

See accompanying notes to consolidated financial statements

1. Organization and Basis of Presentation

Organization. The consolidated financial statements presented herein contain the results of Regency Energy Partners LP and its subsidiaries ("Partnership"), a Delaware limited partnership. The Partnership was formed on September 8, 2005, and completed its IPO on February 3, 2006. The Partnership and its subsidiaries are engaged in the business of gathering, processing and transporting natural gas and NGLs as well as providing contract compression services. Regency GP LP is the Partnership's general partner and Regency GP LLC (collectively the "General Partner") is the managing general partner of the Partnership and the general partner of Regency GP LP.

On June 18, 2007, indirect subsidiaries of GECC acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners and acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership's management. The Partnership was not required to record any adjustments to reflect the acquisition of the HM Capital Partners' interest in the Partnership or the related transactions (together, referred to as "GE EFS Acquisition").

In January 2008, the Partnership acquired all of the outstanding equity and noncontrolling interest (the "FrontStreet Acquisition") of FrontStreet from ASC, an affiliate of GECC, and EnergyOne. Because the acquisition of ASC's 95 percent interest was a transaction between commonly controlled entities, the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Information included in these financial statements is presented as if the FrontStreet Acquisition had been combined throughout the periods presented in which common control existed, June 18, 2007 forward. Conversely, the acquisition of EnergyOne's noncontrolling interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting.

In March 2009, the Partnership contributed RIGS to a HPC in exchange for a noncontrolling interest in that joint venture. Accordingly, the Partnership no longer consolidates RIGS in its financial statements, and accounts for its investment in HPC under the equity method. Transactions between the Partnership and HPC involve the transportation of natural gas, contract compression services, and the provision of administrative support. Because these transactions are immediately realized, the Partnership does not eliminate these transactions with its equity method investee.

Basis of presentation. The consolidated financial statements of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Restricted Cash. Restricted cash of $1,511,000 is held in escrow for purchase indemnifications related to the El Paso acquisition and for environmental remediation projects. A third-party agent invests funds held in escrow in US Treasury securities. Interest earned on the investment is credited to the escrow account.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20 percent voting interest or exerts significant influence over an investee and where the Partnership lacks control over the investee.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Sales or retirements of assets, along with the related accumulated depreciation, are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2009, 2008, and 2007, the Partnership capitalized interest of $1,722,000, $2,409,000 and $1,754,000, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

The Partnership accounts for its asset retirement obligations by recognizing on its balance sheet the net present value of any legally-binding obligation to remove or remediate the physical assets that it retires from service, as well as any similar obligations for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Partnership. While the Partnership is obligated under contractual agreements to remove certain facilities upon their retirement, management is unable to reasonably determine the fair value of such asset retirement obligations because the settlement dates, or ranges thereof, were indeterminable and could range up to 95 years, and the undiscounted amounts are immaterial. An asset retirement obligation will be recorded in the periods wherein management can reasonably determine the settlement dates.

Depreciation expense related to property, plant and equipment was $97,426,000, $88,828,000, and $50,719,000 for the years ended December 31, 2009, 2008, and 2007, respectively. Depreciation of plant and equipment is recorded on a straight-line basis over the following estimated useful lives.

Functional Class of Property	Useful Lives (Years)
Gathering and transmission systems	5 - 20
Compression equipment	10 - 30
Gas plants and buildings	15 - 35
Other property, plant and equipment	3 - 10

Intangible Assets. Intangible assets consisting of (i) permits and licenses, (ii) customer contracts, (iii) trade name, and (iv) customer relations are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from three to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2009, 2008 or 2007.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of December 31, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. No impairment was indicated for the years ended December 31, 2009, 2008, or 2007.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt. Taxes incurred on behalf of, and passed through to, the Partnership's compression customers are accounted for on a net basis.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2009 and 2008 were immaterial.

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas at a price approximating the index price and NGLs to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses ethane, propane, butane, natural gasoline, and condensate swaps to create offsetting positions to specific commodity price exposures. Derivative financial instruments are recorded on the balance sheet at their fair value on a net basis by settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Derivative financial instruments qualifying for hedge accounting treatment have been designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. If the Partnership determines that a derivative is no longer highly effective as a hedge, it discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions. For the Partnership's derivative financial instruments that were not designated for hedge accounting, the change in market value is recorded as a component of net unrealized and realized gain (loss) from derivatives in the consolidated statements of operations.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The Partnership provides a matching contribution for employee contributions to their 401(k) accounts, which vests ratably over 3 years. The amount of matching contributions for the years ended December 31, 2009, 2008, and 2007 were $1,440,000, $395,000, and $469,000, respectively, and were recorded in general and administrative expenses. The Partnership has no pension obligations or other post employment benefits.

Income Taxes. The Partnership is generally not subject to income taxes, except as discussed below, because its income is taxed directly to its partners. The Partnership is subject to the gross margin tax enacted by the state of Texas. The Partnership has wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method for these entities. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership's deferred tax liability of $6,996,000 and $8,156,000 as of December 31, 2009 and 2008 relates to the difference between the book and tax basis of property, plant and equipment and intangible assets and is included in other long-term liabilities in the accompanying consolidated balance sheet. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2009 and 2008. The Partnership's entities that are required to pay federal income tax recognized current federal income tax benefit of $420,000 and deferred income tax benefit of $1,160,000 using a 35 percent effective rate during the year ended December 31, 2009.

As of December 31, 2009, the IRS is conducting an audit to the tax returns of Pueblo Holdings Inc., a wholly-owned subsidiary of the Partnership, for the tax years ended December 31, 2007 and December 31, 2008. In addition, on January 27, 2010, the IRS mailed two "Notice of Beginning of Administrative Proceeding" to the Partnership stating that the IRS is commencing audits of the Partnership's 2007 and 2008 partnership tax returns.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

Earnings per Unit. Basic net income per common unit is computed through the use of the two-class method, which allocates earnings to each class of equity security based on their participation in distributions and deemed distributions. Accretion of the Series A Convertible Redeemable Preferred Units ("Series A Preferred Units") and the beneficial conversion feature related to the Class D common units are considered deemed distributions. Distributions and deemed distributions to the Series A Preferred Units as well as the beneficial conversion feature of the Class D common units reduce the amount of net income available to the general partner and limited partner interests. The general partners' interest in net income or loss consists of its two percent interest, make-whole allocations for any losses allocated in a prior tax year and incentive distribution rights ("IDRs"). After deducting the General Partner's interest, the limited partners' interest in the remaining net income or loss is allocated to each class of equity units based on distributions and beneficial conversion feature amounts, if applicable, then divided by the weighted average number of common and subordinated units outstanding in each class of security. Diluted net income per common unit is computed by dividing limited partners' interest in net income, after deducting the General Partner's interest, by the weighted average number of units outstanding and the effect of non-vested restricted units, phantom units, Series A Preferred Units and unit options computed using the treasury stock method. Common and subordinated units are considered to be a single class. For special classes of common units issued with a beneficial conversion feature, the amount of the benefit associated with the period is added back to net income and the unconverted class is added to the denominator.

Revision to Partners' Capital Accounts. In 2009, the Partnership revised the allocation of net income between the General Partner and common unitholders from the third quarter of 2008 to reflect the income allocation provisions of the Partnership agreement. The effect of this revision is not material to the prior financial statements.

Recently Issued Accounting Standards. In June 2009, the FASB issued guidance that significantly changed the consolidation model for variable interest entities. The guidance is effective for annual reporting periods that begin after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership has evaluated this guidance and determined that it will have no impact on its financial position, results of operations or cash flows as a result of adopting this guidance on January 1, 2010.

In January 2010, the FASB issued guidance requiring improved disclosure of transfers in and out of Levels 1 and 2 for an entity’s fair value measurements, such requirement becoming effective for interim and annual periods beginning after December 15, 2009. Further, additional disclosure of activities such as purchases, sales, issuances and settlements of items relying on Level 3 inputs will be required, such requirements becoming effective for interim and annual periods beginning after December 15, 2010. The Partnership has evaluated this guidance and determined that it will have no impact on its financial position, results of operations or cash flows upon adopting this guidance.

3. Partners’ Capital and Distributions

Common Unit Offerings. In August 2008, the Partnership sold 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner’s proportionate capital contribution. In December 2009, the Partnership sold 12,075,000 common units and received $225,030,000 in proceeds, inclusive of the General Partner’s proportionate capital contribution.

Subordinated Units. The subordinated units converted into common units on a one-for-one basis on February 17, 2009.

Class E Common Units. On January 7, 2008, the Partnership issued 4,701,034 of Class E common units to ASC as consideration for the FrontStreet Acquisition. The Class E common units had the same terms and conditions as the Partnership’s common units, except that the Class E common units were not entitled to participate in earnings or distributions by the Partnership. The Class E common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Class D Common Units. On January 15, 2008, the Partnership issued 7,276,506 of Class D common units to CDM as partial consideration for the CDM acquisition. The Class D common units had the same terms and conditions as the Partnership’s common units, except that the Class D common units were not entitled to participate in earnings or distributions by the Partnership. The Class D common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class D common units converted into common units without the payment of further consideration on a one-for-one basis on February 9, 2009.

Noncontrolling Interest. The Partnership operates a gas gathering joint venture in south Texas in which a third party owns a 40 percent interest, which is reflected on the balance sheet in noncontrolling interest.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the general partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

General Partner Interest and Incentive Distribution Rights. The General Partner is entitled to 2 percent of all quarterly distributions that the Partnership makes prior to its liquidation. This General Partner interest is represented by 1,901,803 equivalent units as of December 31, 2009. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2 percent interest in these distributions will be reduced if the Partnership issues additional units in the future and the General Partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2 percent General Partner interest.

The incentive distribution rights held by the General Partner entitles it to receive an increasing share of Available Cash when pre-defined distribution targets are achieved. The General Partner's incentive distribution rights are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2 percent general partner interest.

Distributions of Available Cash. The partnership agreement requires that it make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- first, 98 percent to all unitholders, pro rata, and 2 percent to the General Partner, until each unitholder receives a total of $0.35 per unit for that quarter;
- second, 98 percent to all unitholders, pro rata, and 2 percent to the General Partner, until each unitholder receives a total of $0.4025 per unit for that quarter;
- third, 85 percent to all unitholders, pro rata, 13 percent to holders of the incentive distribution rights, and 2 percent to the General Partner, until the aggregate distributions equal $0.4375 per unit outstanding for that quarter;
- fourth, 75 percent to all unitholders, pro rata, 23 percent to holders of the incentive distribution rights, and 2 percent to the General Partner, until the aggregate distributions equal $0.525 per unit outstanding for that quarter; and
- thereafter, 50 percent to all unitholders, pro rata, 48 percent to holders of the incentive distribution rights, and 2 percent to the General Partner.

Distributions. The Partnership made the following cash distributions per unit during the years ended December 31, 2009 and 2008:

Distribution Date	Cash Distribution (per Unit)
November 13, 2009	$ 0.445
August 14, 2009	0.445
May 14, 2009	0.445
February 13, 2009	0.445
November 14, 2008	0.445
August 14, 2008	0.445
May 14, 2008	0.420
February 14, 2008	0.400

4. Income (Loss) per Limited Partner Unit

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per unit computations for the years ended December 31, 2009 and 2008.

	For the Year Ended December 31, 2009			For the Year Ended December 31, 2008		
	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)					
Basic Earnings per Unit						
Limited partners' interests	$ 129,366	80,582,705	$ 1.61	$ 88,645	66,190,626	$ 1.34
Effect of Dilutive Securities						
Restricted (non-vested) common units	—	—		—	5,451	
Common unit options	—	—		—	30,580	
Phantom units	—	100,764		—	—	
Class D common units	820	797,425		7,199	6,978,289	
Class E common units	—	—		—	1,618,389	
Diluted Earnings per Unit	$ 130,186	81,480,894	$ 1.60	$ 95,844	74,823,335	$ 1.28

For the year ended December 31, 2007, diluted earnings per unit equals basic because all instruments were antidilutive.

In connection with the CDM acquisition discussed below, the Partnership issued 7,276,506 Class D common units. At the commitment date, the sales price of $30.18 per unit represented a $1.10 discount from the fair value of the Partnership's common units. This discount represented a beneficial conversion feature that is treated as a non-cash distribution for purposes of calculating earnings per unit. The beneficial conversion feature is reflected in income per unit using the effective yield method over the period the Class D common units were outstanding, as indicated on the statements of operations in the line item entitled "beneficial conversion feature for Class D common units."

In connection with the FrontStreet acquisition, the Partnership issued 4,701,034 Class E common units to ASC, an affiliate of GECC. Because this transaction represented the acquisition of an entity under common control, the Partnership applied a method of accounting similar to a pooling of interests. The amount of net income allocated to the Class E common units represents amounts earned by FrontStreet between the date of common control and the transaction date. The amount of distributions per unit reflects amounts paid out to the owners of FrontStreet prior to the acquisition.

The following data show securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit because to do so would have been antidilutive for the periods presented.

	For the Year Ended December 31,		
	2009	2008	2007
Restricted (non-vested) common units	566,493	—	397,500
Common unit options	357,489	—	738,668
Convertible redeemable preferred units	1,449,211	—	—

The partnership agreement requires that the General Partner shall receive a 100 percent allocation of income until its capital account is made whole for all of the net losses allocated to it in prior years.

5. Acquisitions and Dispositions

2009

HPC. In March 2009, the Partnership completed a joint venture arrangement among Regency HIG, EFS Haynesville, and the Alinda Investors. The Partnership contributed RIG, which owns the Regency Intrastate Gas System, with a fair value of $401,356,000, to HPC, in exchange for a 38 percent interest in HPC. EFS Haynesville and Alinda Investors contributed $126,928,000 and $528,284,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent interest, respectively. The disposition and deconsolidation resulted in the recording of a $133,451,000 gain (of which $52,813,000 represents the remeasurement of the Partnership's retained 38 percent interest to its fair value), net of transaction costs of $5,530,000.

In September 2009, the Partnership purchased a five percent interest in HPC from EFS Haynesville for $63,000,000, increasing the Partnership's ownership percentage from 38 percent to 43 percent. Because the transaction occurred between two entities under common control, the Partnership's general partner interest was reduced by $10,197,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount.

2008

FrontStreet. In January 2008, the Partnership completed the FrontStreet Acquisition. FrontStreet owned a gas gathering system located in Kansas and Oklahoma, which is operated by a third party. The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price with borrowings under its revolving credit facility.

Because the acquisition of ASC's 95 percent interest was a transaction between commonly controlled entities, the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Information included in these financial statements is presented as if the FrontStreet Acquisition had been combined throughout the periods presented in which common control existed, June 18, 2007 forward. Conversely, the acquisition of the five percent minority interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting.

The following table summarizes the book value of the assets acquired and the liabilities assumed at the date of common control, following the as if pooled method of accounting.

	At June 18, 2007 (in thousands)
Current assets	$ 8,840
Property, plant and equipment	91,556
Total assets acquired	100,396
Current liabilities	(12,556)
Net book value of assets acquired	$ 87,840

CDM Resource Management, Ltd. In January 2008, the Partnership acquired CDM by (a) issuing an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000 and (b) paying an aggregate of $478,445,000 in cash, $316,500,000 of which was used to retire CDM's debt obligations.

The total purchase price of $699,841,000, including direct transaction costs, was allocated as follows.

	At January 15, 2008 (in thousands)
Current assets	$ 19,463
Other assets	4,658
Gas plants and buildings	1,528
Gathering and transmission systems	420,974
Other property, plant and equipment	2,728
Construction-in-process	36,239
Identifiable intangible assets	80,480
Goodwill	164,882
Assets acquired	730,952
Current liabilities	(31,054)
Other liabilities	(57)
Net assets acquired	$ 699,841

Nexus Gas Holdings, LLC. In March 2008, the Partnership acquired Nexus ("Nexus Acquisition") for $88,486,000 in cash. The Partnership funded the Nexus Acquisition through borrowings under its existing credit facility.

The total purchase price of $88,640,000 was allocated as follows.

	At March 25, 2008 (in thousands)
Current assets	$ 3,457
Buildings	13
Gathering and transmission systems	16,960
Other property, plant and equipment	4,440
Identifiable intangible assets	61,100
Goodwill	3,341
Assets acquired	89,311
Current liabilities	(671)
Net assets acquired	$ 88,640

2007

Palafox Joint Venture. The Partnership acquired the outstanding interest in the Palafox Joint Venture not owned (50 percent) for $5,000,000 effective February 1, 2007. The Partnership allocated $10,057,000 to gathering and transmission systems in the three months ended March 31, 2007. The allocated amount consists of the investment in unconsolidated subsidiary of $5,650,000 immediately prior to the Partnership's acquisition and the Partnership's $5,000,000 purchase of the remaining interest offset by $593,000 of working capital accounts acquired.

Significant Asset Dispositions. The Partnership sold selected non-core pipelines, related rights of way and contracts located in south Texas for $5,340,000 on March 31, 2007 and recorded a loss on sale of $1,808,000. Additionally, the Partnership sold two small gathering systems and associated contracts located in the Mid-continent region for $1,750,000 on May 31, 2007 and recorded a loss on the sale of $469,000. The Partnership also sold its 34 mile NGL pipeline located in east Texas for $3,000,000 on June 29, 2007 and simultaneously entered into transportation and operating agreements with the buyer. The Partnership accounted for this transaction as a sale-leaseback whereby the $3,000,000 gain was deferred and will be amortized to earnings over a 20 year period. The Partnership recorded $3,000,000 in gathering and transmission systems and the related obligations under capital lease. On August 31, 2007, the Partnership sold an idle processing plant for $1,300,000 and recorded a $740,000 gain.

Acquisition of Pueblo Midstream Gas Corporation. In April 2007, the Partnership and its indirect wholly-owned subsidiary, Pueblo Holdings, acquired all the outstanding equity of Pueblo. The purchase price for the Pueblo acquisition consisted of (1) the issuance of 751,597 common units of the Partnership to the members, valued at $19,724,000 and (2) the payment of $34,855,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $108,000. The cash portion of the consideration was financed out of the proceeds of the Partnership's credit facility.

The Pueblo acquisition offered the opportunity to reroute gas to one of the Partnership's existing gas processing plants to provide cost savings. The total purchase price was allocated as follows based on estimates of the fair values of assets acquired and liabilities assumed.

	At April 2, 2007 (in thousands)
Current assets	$ 1,295
Gas plants and buildings	8,994
Gathering and transmission systems	13,079
Other property, plant and equipment	180
Intangible assets subject to amortization (contracts)	5,242
Goodwill	36,523
Assets acquired	65,313
Current liabilities	(1,187)
Long-term liabilities	(9,492)
Total Purchase price	$ 54,634

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM, Nexus and Pueblo, as well as the contribution of RIG to HPC as well as the acquisition of additional five percent HPC interest had occurred as of the beginning of the earliest period presented. Such unaudited pro forma financial information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the Year Ended December 31,		
	2009	2008	2007
	(in thousands except unit and per unit data)		
Revenue	$ 1,077,524	$ 1,822,722	$ 1,274,829
Net income attributable to Regency Energy Partners LP	5,844	81,691	112,474
Less:			
Amounts attributable to Series A Convertible Redeemable Preferred Units	7,781	7,781	7,781
General partner's interest, including IDR	2,485	3,769	1,980
Amount allocated to non-vested common units	(266)	491	669
Beneficial conversion feature for Class C common units	—	—	1,385
Beneficial conversion feature for Class D common units	820	7,199	—
Amount allocated to Class E common units	—	—	5,792
Limited partners' interest	$ (4,976)	$ 62,451	$ 94,867
Basic and Diluted earnings per unit:			
Amount allocated to common and subordinated units	$ (4,976)	$ 62,451	$ 94,867
Weighted average number of common and subordinated units outstanding	80,582,705	66,190,626	51,056,769
Basic (loss) income per common and subordinated unit	$ (0.06)	$ 0.94	$ 1.86
Diluted (loss) income per common and subordinated unit	$ (0.06)	$ 0.94	$ 1.59
Distributions paid per unit	$ 1.78	$ 1.71	$ 1.52
Amount allocated to Class B common units	$ —	$ —	$ —
Weighted average number of Class B common units outstanding	—	—	651,964
Income per Class B common unit	$ —	$ —	$ —
Distributions per unit	$ —	$ —	$ —
Amount allocated to Class C common units	$ —	$ —	$ 1,385
Total number of Class C common units outstanding	—	—	2,857,143
Income per Class C common unit due to beneficial conversion feature	$ —	$ —	$ 0.48
Distributions per unit	$ —	$ —	$ —
Amount allocated to Class D common units	$ 820	$ 7,199	$ —
Total number of Class D common units outstanding	7,276,506	7,276,506	7,276,506
Income per Class D common unit due to beneficial conversion feature	$ 0.11	$ 0.99	$ —
Distributions per unit	$ —	$ —	$ —
Amount allocated to Class E common units	$ —	$ —	$ 5,792
Total number of Class E common units outstanding	—	—	4,701,034
Income per Class E common unit	$ —	$ —	$ 1.23
Distributions per unit	$ —	$ —	$ 2.06

6. Investment in Unconsolidated Subsidiary

As described in the Acquisitions and Dispositions footnote, the Partnership contributed RIG to HPC for a 38 percent partner's interest in HPC. Subsequently, on September 2, 2009, the Partnership purchased an additional five percent partner's interest in HPC from EFS Haynesville for $63,000,000. The Partnership recognized $7,886,000 in income from unconsolidated subsidiary for its ownership interest and received $8,926,000 of distributions from HPC from inception (March 18, 2009) to December 31, 2009. The summarized financial information of HPC for the period from inception (March 18, 2009) to December 31, 2009 is disclosed below.

RIGS Haynesville Partnership Co.
Condensed Consolidated Balance Sheet
December 31, 2009
(in thousands)

ASSETS	
Total current assets	$ 39,239
Restricted cash, non-current	33,595
Property, plant and equipment, net	861,570
Total other assets	149,755
TOTAL ASSETS	$ 1,084,159
LIABILITIES & PARTNERS' CAPITAL	
Total current liabilities	$ 30,967
Partners' capital	1,053,192
TOTAL LIABILITIES & PARTNERS' CAPITAL	$ 1,084,159

RIGS Haynesville Partnership Co.
Condensed Consolidated Income Statement
From Inception (March 18, 2009) to December 31, 2009
(in thousands)

Total revenues	$43,483
Total operating costs and expenses	24,926
OPERATING INCOME	18,557
Interest expense	(158)
Other income and deductions, net	1,335
NET INCOME	$19,734

The HPC partnership agreement requires the distribution of 100 percent of "available cash" to the partners in accordance with their sharing ratios within 30 days after the end of each calendar quarter. Available cash is defined as cash on hand (excluding cash restricted for the Haynesville Expansion Project), less amounts reserved for normal operating expenses.

7. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Risk Management Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operation. The prices of these commodities are impacted by changes in the supply and demand as well as market focus. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. It is the Partnership's policy not to take any speculative positions with its derivative contracts.

The Partnership has executed swap contracts settled against NGLs (ethane, propane, butane, and natural gasoline), condensate and natural gas market prices for expected exposure in the approximate percentages set for below.

	As of December 31, 2009	
	2010	2011
NGLs	80%	33%
Condensate	84%	21%
Natural gas	85%	27%

At December 31, 2009, the 2010 and 2011 natural gas and 2010 condensate swaps are accounted for as cash flow hedges; the 2011 condensate swaps are accounted for using mark-to-market accounting; and the 2010 and 2011 NGLs swaps are accounted for using a combination of cash flow hedge accounting and mark-to-market accounting.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its credit facility. As of December 31, 2009, the Partnership had $419,642,000 of outstanding borrowings exposed to variable interest rate risk. In February 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (3.0 percent as of December 31, 2009) through March 5, 2010. These interest rate swaps were designated as cash flow hedges.

Credit Risk. The Partnership's resale of natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives. The Partnership has entered into Master International Swap Dealers Association ("ISDA") Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss is $25,246,000, which would be reduced by $13,284,000 due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. Changes in the fair value are recorded in other income and deductions, net within the consolidated statement of operations. The Partnership does not expect the embedded derivatives to affect its cash flows. During the year ended December 31, 2009, the loss recognized related to these embedded derivatives was $15,686,000 and is reflected in other income and deductions, net on the consolidated statement of operations.

Quantitative Disclosures. The Partnership expects to reclassify $1,271,000 of net hedging losses to revenue or interest expense from accumulated other comprehensive income in the next 12 months.

The Partnership's derivative assets and liabilities, including credit risk adjustment, for the years ending December 31, 2009 and 2008 are detailed below.

	Assets		Liabilities	
	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$ —	$ —	$ 1,067	$ 4,680
Commodity contracts	9,525	59,882	11,200	—
Long-term amounts				
Interest rate contracts	—	—	—	560
Commodity contracts	207	13,373	931	—
Total cash flow hedging instruments	9,732	73,255	13,198	5,240
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	15,514	16,001	31	38,402
Long-term amounts				
Commodity contracts	—	23,425	3,378	—
Embedded derivatives in Series A Preferred Units	—	—	44,594	—
Total derivatives not designated as cash flow hedges	15,514	39,426	48,003	38,402
Credit Risk Assessment				
Current amounts	(52)	(1,890)	(42)	(391)
Total derivatives	$ 25,194	$ 110,791	$ 61,159	$ 43,251

Derivatives designated as cash flow hedges

	Year Ended December 31, 2009			Year Ended December 31, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
	(in thousands)					
Gain (loss) recorded in accumulated OCI (Effective)	$(2,082)	$ (19,958)	$(22,040)	$(4,555)	$ 74,808	$ 70,253
Gain (loss) reclassified from accumulated OCI into income (Effective)*	(6,255)	54,260	48,005	676	(35,942)	(35,266)
Gain (loss) recognized in income (Ineffective)*	—	108	108	—	543	543

Derivatives not designated as cash flow hedges

	Year Ended December 31, 2009			Year Ended December 31, 2008		
	Embedded Derivatives	Commodity	Total	Embedded Derivatives	Commodity	Total
	(in thousands)					
Loss from dedesignation amortized from accumulated OCI into income*	$ —	$ (611)	$ (611)	$ —	$ (246)	$ (246)
(Loss) gain recognized in income*	(15,686)	(13,669)	(29,355)	—	15,911	15,911

Credit risk assessment for commodity and interest rate swaps

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Gain (loss) recognized in income*	$1,489	$(1,499)	$—

* Gain and loss related to commodity swaps, interest swaps and embedded derivatives were included in revenue, interest expense, and other income and deductions, net, respectively, in the Partnership's consolidated statements of operations.

8. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows.

	December 31, 2009	December 31, 2008
	(in thousands)	
Senior notes	$ 594,657	$ 357,500
Revolving loans	419,642	768,729
Total	1,014,299	1,126,229
Less: current portion	—	—
Long-term debt	$1,014,299	$1,126,229
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded Lehman commitments	(10,675)	(8,646)
Revolving loans	(419,642)	(768,729)
Letters of credit	(16,257)	(16,257)
Total available	$ 453,426	$ 106,368

Long-term debt maturities as of December 31, 2009 for each of the next five years are as follows.

Year Ended December 31,	Amount
	(in thousands)
2010	$ —
2011	419,642
2012	—
2013	357,500
2014	—
Thereafter	250,000*
Total	$ 1,027,142

* As of December 31, 2009, the carrying value of the senior notes due 2016 was $237,157,000 which included an unamortized discount of $12,843,000.

In the year ended December 31, 2009, the Partnership borrowed $191,693,000 under its credit facility; these borrowings were primarily to fund capital expenditures. During the same period, the Partnership repaid $540,780,000 with proceeds from an equity offering and issuance of senior notes due 2016. In the years ended December 31, 2008 and 2007, the Partnership borrowed $844,729,000 and $283,230,000, respectively; these funds were used primarily to finance capital expenditures. During the same periods, the Partnership repaid $200,000,000 and $421,430,000, respectively, of these borrowings with proceeds from equity offerings.

Senior Notes due 2016. In May 2009, the Partnership and Finance Corp. issued $250,000,000 of senior notes in a private placement that mature on June 1, 2016. The senior notes bear interest at 9.375 percent with interest payable semi-annually in arrears on June 1 and December 1. The Partnership paid a $13,760,000 discount upon issuance. The net proceeds were used to partially repay revolving loans under the Partnership's credit facility.

At any time before June 1, 2012, up to 35 percent of the senior notes can be redeemed at a price of 109.375 percent plus accrued interest. Beginning June 1, 2013, the Partnership may redeem all or part of these notes for the principal amount plus a declining premium until June 1, 2015, and thereafter at par, plus accrued and unpaid interest. At any time prior to June 1, 2013, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) one percent of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at June 1, 2013 plus (ii) all required interest payments due on the note through June 1, 2013, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points over the principal amount of the note.

Upon a change of control, each noteholder will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages, if any. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of its debt agreements, including its credit facility.

The senior notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the senior notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At December 31, 2009, the Partnership was in compliance with these covenants.

The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Finance Corp., and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's credit facility, to the extent of the value of the assets securing such obligations.

Senior Notes due 2013. In 2006, the Partnership and Finance Corp. issued $550,000,000 senior notes that mature on December 15, 2013 in a private placement. The senior notes bear interest at 8.375 percent and interest is payable semi-annually in arrears on each June 15 and December 15. In August 2007, the Partnership exercised its option to redeem 35 percent or $192,500,000 of these senior notes at a price of 108.375 percent of the principal amount plus accrued interest. Accordingly, a redemption premium of $16,122,000 and a loss on debt refinancing and unamortized loan origination costs of $4,575,000 were charged to loss on debt refinancing in the year ended December 31, 2007. Under the senior notes terms, no further redemptions are permitted until December 15, 2010.

The Partnership may redeem the outstanding senior notes, in whole or in part, at any time on or after December 15, 2010, at a redemption price equal to 100 percent of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest and liquidated damages, if any, to the redemption date.

Upon a change of control, each noteholder will be entitled to require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages, if any. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of its debt agreements, including its credit facility.

The senior notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the senior notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At December 31, 2009, the Partnership was in compliance with these covenants.

The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Finance Corp., and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's credit facility, to the extent of the value of the assets securing such obligations.

Finance Corp. has no operations and will not have revenue other than as may be incidental as co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except certain wholly owned subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

GECC Credit Facility. On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC. The proceeds of the GECC Credit Facility were available for expenditures made in connection with the Haynesville Expansion Project prior to the effectiveness of the March 17, 2009 amendment discussed below. The commitments under the GECC Credit Facility terminated on March 17, 2009. The Partnership paid a commitment fee of $2,718,000 to GECC related to this GECC Credit Facility, which was recorded as a decrease to gain on asset sales, net.

Fourth Amended and Restated Credit Agreement. In February 2008, RGS' Fourth Amended and Restated Credit Agreement was expanded to $900,000,000 and the availability for letters of credit was increased to $100,000,000. The Partnership also has the option to request an additional $250,000,000 in revolving commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the credit facility have been met. The maturity date of the Credit Facility is August 15, 2011.

Effective March 17, 2009, RGS amended the credit facility to authorize the contribution of RIG to HPC and allow for a future investment of up to $135,000,000 in HPC. The amendment imposed additional financial restrictions that limit the ratio of senior secured indebtedness to EBITDA. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50 percent and an adjusted one-month LIBOR rate plus 1.50 percent. The applicable margin shall range from 1.50 percent to 2.25 percent for base rate loans, 2.50 percent to 3.25 percent for Eurodollar loans, and a commitment fee will range from 0.375 to 0.500 percent. On July 24, 2009, RGS further amended its credit facility to allow for a $25,000,000 working capital facility for RIG. These amendments did not materially change other terms of the RGS revolving credit facility.

On September 15, 2008, Lehman filed a petition in the United States Bankruptcy Court seeking relief under Chapter 11 of the United States Bankruptcy Code. As a result, a subsidiary of Lehman that is a committed lender under the Partnership's credit facility has declined requests to honor its commitment to lend. The total amount committed by Lehman was $20,000,000 and as of December 31, 2009, the Partnership had borrowed all but $10,675,000 of that amount. Since Lehman has declined requests to honor its remaining commitment, the Partnership's total size of the credit facility's capacity has been reduced from $900,000,000 to $889,325,000. Further, if the Partnership makes repayments of loans against the credit facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed.

The outstanding balance of revolving loans under the credit facility bears interest at LIBOR plus a margin or Alternative Base Rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.69 percent, 6.27 percent, and 8.78 percent for the years ended December 31, 2009, 2008, and 2007, respectively. The senior notes pay fixed interest rates and the weighted average rate is 8.787 percent.

RGS must pay (i) a commitment fee equal to 0.50 percent per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit equal to 3.0 percent per annum of the average daily amount of such lender's letter of credit exposure, and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.125 percent per annum of the average daily amount of the letter of credit exposure.

The credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to adjusted EBITDA (as defined in the credit agreement) ratio less than 5.25, and adjusted EBITDA to interest expense ratio greater than 2.75 times. At December 31, 2009 and 2008, RGS and its subsidiaries were in compliance with these covenants.

The credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the extent of the Partnership's determination of available cash (so long as no default or event of default has occurred or is continuing). The credit facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the credit facility or reasonable extensions thereof.

9. Other Assets

Intangible assets, net. Intangible assets, net consist of the following.

	Permits and Licenses	Contracts	Trade Names	Customer Relations	Total
			(in thousands)		
Balance at January 1, 2008	$ 9,368	$ 68,436	$ —	$ —	$ 77,804
Additions	—	64,770	35,100	41,710	141,580
Amortization	(786)	(6,407)	(2,252)	(4,293)	(13,738)
Balance at December 31, 2008	8,582	126,799	32,848	37,417	205,646
Disposals	(2,921)	—	—	—	(2,921)
Other	—	7,000	—	—	7,000
Amortization	(569)	(7,467)	(2,340)	(2,055)	(12,431)
Balance at December 31, 2009	$ 5,092	$126,332	$ 30,508	$35,362	$197,294

The average remaining amortization periods for permits and licenses, contracts, trade names, and customer relations are 10, 16, 13 and 18 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total
	(in thousands)
2010	$ 12,553
2011	11,244
2012	11,002
2013	11,002
2014	11,002

Goodwill. Goodwill activity consists of the following.

	Gathering and Processing	Transportation	Contract Compression	Total
		(in thousands)		
Balance at January 1, 2008	$ 59,831	$ 34,244	$ —	$ 94,075
Additions	3,401	—	164,882	168,283
Balance at December 31, 2008	63,232	34,244	164,882	262,358
Disposals	—	(34,244)	—	(34,244)
Balance at December 31, 2009	$ 63,232	$ —	$ 164,882	$ 228,114

On March 17, 2009, the Partnership contributed all assets of RIG, which owns the Regency Intrastate Gas System, to HPC, in exchange for an interest in HPC. As a result, goodwill associated with the transportation segment was removed from the balance sheet.

10. Fair Value Measures

On January 1, 2008, the Partnership adopted the fair value measurement provisions for financial assets and liabilities and on January 1, 2009, the Partnership applied the fair value measurement provisions to non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. These provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

Derivatives. The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate and commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy. The change in fair value of the derivatives related to Series A Preferred Units is recorded in other income and deductions, net within the statement of operations.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis.

	December 31, 2009		December 31, 2008	
	Assets	Liabilities	Assets	Liabilities
	(in thousands)			
Level 1	$ —	$ —	$ —	$ —
Level 2	25,194	16,565	110,791	43,251
Level 3	—	44,594	—	—
Total	$ 25,194	$ 61,159	$ 110,791	$ 43,251

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the year ended December 31, 2009. There were no Level 3 derivatives for the years ended December 31, 2008 or 2007.

	Derivatives related to Series A Preferred Units For the Year Ended December 31, 2009 (in thousands)
Beginning Balance	$ —
Issuance	28,908
Net unrealized losses included in other income and deductions, net	15,686
Ending Balance	$ 44,594

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. Long-term debt, other than the senior notes, is comprised of borrowings under which, interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair value of the senior notes due 2013 based on third party market value quotations as of December 31, 2009 and 2008 was $364,650,000 and $244,888,000, respectively. The estimated fair value of the senior notes due 2016 based on third party market value quotations as of December 31, 2009 was $265,625,000.

11. Leases

The Partnership leases office space and certain equipment and the following table is a schedule of future minimum lease payments for leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2009.

For the year ending December 31,	Operating	Capital
	(in thousands)	
2010	$ 3,838	$ 589
2011	3,801	422
2012	3,426	436
2013	2,714	448
2014	2,351	462
Thereafter	9,975	7,101
Total minimum lease payments	$ 26,105	$ 9,458
Less: Amount representing estimated executory costs (such as maintenance and insurance), including profit thereon, included in minimum lease payments		1,890
Net minimum lease payments		7,568
Less: Amount representing interest		4,365
Present value of net minimum lease payments		$ 3,203

The following table sets forth the Partnership's assets and obligations under the capital lease which are included in other current and long-term liabilities on the consolidated balance sheet.

	December 31, 2009 (in thousands)
Gross amount included in gathering and transmission systems	$ 3,000
Gross amount included in other property, plant and equipment	560
Less accumulated depreciation	(755)
	$ 2,805
Current obligation under capital lease	529
Non-current obligation under capital lease	2,674
	$ 3,203

Total rent expense for operating leases, including those leases with terms of less than one year, was $5,465,000, $2,576,000, and $1,597,000, for the years ended December 31, 2009, 2008, and 2007, respectively.

12. Commitments and Contingencies

Legal. The Partnership is involved in various claims and lawsuits incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Escrow Payable. At December 31, 2009, $1,511,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area and a subsequent 2008 settlement agreement between the Partnership and El Paso. In the El Paso PSA, El Paso indemnified Regency Gas Services LLC, now known as Regency Gas Services LP, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion.

Environmental. A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made against the Partnership or under the policy.

TCEQ Notice of Enforcement. In February 2008, the TCEQ issued a Notice of Enforcement ("NOE") concerning one of the Partnership's processing plants located in McMullen County, Texas. The NOE alleged that, between March 9, 2006, and May 8, 2007, this plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. In January 2010, the TCEQ notified the Partnership in writing that it had concluded that there had been no violation and that the TCEQ would take no further action.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership's predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. Discovery ended in October 2009. A hearing on cross-motions for summary judgment took place in December 2009. A decision is expected in the first quarter of 2010. If the Partnership does not win its motion, a jury trial is scheduled for April 2010.

Kansas State Severance Tax. In August 2008, a customer began remitting severance tax to the state of Kansas based on the value of condensate purchased from one of the Partnership's Mid-Continent gathering fields and deducting the tax from its payments to the Partnership. The Kansas Department of Revenue advised the customer that it was appropriate to remit such taxes and withhold the taxes from its payments to the Partnership, absent an order or legal opinion from the Kansas Department of Revenue stating otherwise. The Partnership has requested a determination from the Kansas Department of Revenue regarding the matter since severance taxes were already paid on the gas from which the condensate is collected and no additional tax is due. The Kansas Department of Revenue has initiated an audit of the Partnership's condensate sales in Kansas. If the Kansas Department of Revenue determines that the condensate sales are taxable, then the Partnership may be subject to additional taxes, interest and possible penalties for past and future condensate sales.

Caddo Gas Gathering LLC v. Regency Intrastate Gas LLC. Regency Intrastate Gas LLC was a defendant in a lawsuit filed by Caddo Gas Gathering LLC ("Caddo Gas"). In February 2010, the dispute was resolved and the lawsuit dismissed with prejudice without material expense.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. Regency Field Services LLC ("RFS") currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the "Plants"). The Plants each have a groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from El Paso, Kerr-McGee Corporation ("Kerr-McGee") was performing remediation of the groundwater contamination, because the Plants were once owned by Kerr-McGee and when Kerr-McGee sold the Plants to a predecessor of El Paso in 1988, Kerr-McGee retained liability for any environmental contamination at the Plants. In 2005, Kerr-McGee created and spun off Tronox and Tronox allegedly assumed certain of Kerr-McGee's environmental remediation obligations (including its obligation to perform remediation at the Plants) prior to the acquisition of Kerr-McGee by Anadarko Petroleum Corporation. In January 2009, Tronox filed for Chapter 11 bankruptcy protection. RFS filed a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants. Tronox has thus far continued its remediation efforts at the Plants.

13. Series A Convertible Redeemable Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units at a price of $18.30 per unit, less a four percent discount of $3,200,000 and issuance costs of $176,000 for net proceeds of $76,624,000, exclusive of the General Partner's contribution of $1,633,000. The Series A Preferred Units are convertible to common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value"). The Series A Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010.

Distributions on the Series A Preferred Units will be accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. For the year ended December 31, 2009, total accrued distributions per unit was $0.89. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Series A Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ending on March 31, 2010, then if the Partnership fails to pay cash distributions on the Series A Preferred Units, all future distributions on the Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Series A Preferred Unit per quarter, (2) $0.09125 per Series A Preferred Unit per quarter (the “Common Unit Distribution Amount”), payable solely in common units, and (3) $0.09125 per Series A Preferred Unit per quarter (the “PIK Distribution Additional Amount”), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed 1,600,000 in any period of 20 consecutive fiscal quarters.

Upon the Partnership’s breach of certain covenants (a “Covenant Default”), the holders of the Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the “Covenant Default Additional Amount”). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432 percent per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429 percent per quarter while such failure to pay or such Covenant Default continues.

The Series A Preferred Units are convertible, at the holder’s option, into common units commencing on March 2, 2010, provided that the holder must request conversion of at least 375,000 Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits) and until December 31, 2011, based on a weighted average formula in the event the Partnership issues any common units (or securities convertible or exercisable into common units) at a per common unit price below $16.47 per common unit (subject to typical exceptions). The number of common units issuable is equal to the issue price of the Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the “Redeemable Face Amount”), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the “VWAP Price”) is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder’s conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91 percent, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Series A Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150 percent of the then-applicable conversion price for twenty (20) out of the trailing thirty (30) trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 101 percent of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a “Cash Event”), the Partnership must use commercially reasonable efforts to ensure that the holders of the Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 120 percent of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Series A Preferred Units upon consummation of such transaction.

As of December 31, 2009, accrued distributions of $3,891,000 have been added to the value of the Series A Preferred Units and increases the number of common units to 4,584,192 that may be issued upon conversion. Holders may elect to convert Series A Preferred Units to common units beginning on March 2, 2010.

Net proceeds from the issuance of Series A Preferred Units on September 2, 2009 was $76,624,000, of which $28,908,000 was allocated to the initial fair value of the embedded derivatives and recorded into long-term derivative liabilities on the balance sheet. The remaining $47,716,000 represented the initial value of the Series A Preferred Units and will be accreted to $80,000,000 by deducting the accretion amounts from partners' capital over 20 years.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for all income statement periods presented.

	Units	Amount (in thousands)
Beginning balance as of January 1, 2009	—	$ —
Original issuance, net of discount of $3,200	4,371,586	76,624
Amount reclassed to long-term derivative liabilities	—	(28,908)
Accrued distributions	—	3,891
Accretion to redemption value	—	104
Ending balance as of December 31, 2009	4,371,586	$ 51,711

14. Related Party Transactions

In September 2008, HM Capital Partners and affiliates sold 7,100,000 common units for total consideration of $149,100,000, reducing their ownership percentage to an amount less than ten percent of the Partnership's outstanding common units. As a result of this sale, HM Capital Partners is no longer a related party of the Partnership. During the years ended December 31, 2008 and 2007, HM Capital Partners and affiliates received cash disbursements, in conjunction with distributions by the Partnership for limited and general partner interests, of $10,308,000 and $24,392,000, respectively.

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $33,834,000, $26,899,000, and $27,628,000, were recorded in the Partnership's financial statements during the years ended December 31, 2009, 2008, and 2007, respectively, as operating expenses or general and administrative expenses, as appropriate.

Concurrent with the GE EFS acquisition, eight members of the Partnership's senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units for a total consideration of $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

GE EFS and certain members of the Partnership's management made capital contributions aggregating to $6,344,000, $11,746,000 and $7,735,000 to maintain the General Partner's two percent interest in the Partnership for the years ended December 31, 2009, 2008, and 2007, respectively.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS received cash distributions of $51,226,000, $35,054,000, and $14,592,000 during the years ended December 31, 2009, 2008 and 2007, respectively.

As part of the August 1, 2008 common units offering, an affiliate of GECC purchased 2,272,727 common units for total consideration of $50,000,000.

The Partnership's contract compression segment provided contract compression services to CDM MAX LLC ("CDM MAX"). In 2009, CDM MAX was purchased by a third party and, as a result, CDM MAX is no longer a related party. The Partnership's related party revenue associated with CDM MAX was $1,101,000 and $3,712,000 during the years ended December 31, 2009 and 2008, respectively.

Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. Under this agreement the Partnership received $500,000 monthly as a partial reimbursement of its general and administrative costs. The Partnership also incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. For the period from March 18, 2009 to December 31, 2009, the related party general and administrative expenses reimbursed to the Partnership were $4,726,000. On December 18, 2009, the reimbursement amount was amended to $1,400,000 per month effective on the first calendar day in the month subsequent to mechanical completion of the expansion of the Regency Intrastate Gas System (February 1, 2010), subject to an annual escalation beginning March 1, 2011. The amount is recorded as fee revenue in the Partnership's corporate and other segment. Additionally, the Partnership's contract compression segment provides contract compression services to HPC. On the other hand, HPC provides transportation service to the Partnership.

Upon the formation of HPC in March 2009, the Partnership was reimbursed by HPC for construction-in-progress incurred prior to formation of HPC at the cost of $80,608,000. Subsequently, the Partnership sold an additional $7,984,000 of compression equipment to HPC.

The Partnership's related party receivables and related party payables as of December 31, 2009 relate to HPC. The Partnership's related party receivables and related party payables as of December 31, 2008 related to CDM MAX.

As disclosed in Note 1 and in Note 5, the Partnership's acquisition of FrontStreet and contribution of RIGS to HPC are related party transactions.

15. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to ten percent or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

	Reportable Segment	Year Ended December 31, 2009	December 31, 2008 (in thousands)	December 31, 2007
Customer				
Customer A	Gathering and Processing	$ 123,524	*	*
Supplier				
Supplier A	Transportation	$ 14,053	$ 75,464	$ 17,930
Supplier A	Gathering and Processing	143,435	243,075	139,116

* Amounts are less than ten percent of the total revenue or cost of sales.

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

16. Segment Information

In 2009, the Partnership's management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has four reportable segments: (a) gathering and processing, (b) transportation, (c) contract compression and (d) corporate and others. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenue and the associated cost of sales from the gathering and processing segment directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment. The Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

Following the initial contribution of RIG to HPC in March 2009, as well as the subsequent acquisition of an additional five percent interest in HPC, the transportation segment consists exclusively of the Partnership's 43 percent interest in HPC, for which equity method accounting applies. Prior periods have been restated to reflect the Partnership's then wholly-owned subsidiary of Regency Intrastate Gas LLC as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with other pipelines, storage facilities or end-use markets. RIG performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenue is primarily fee based and involves minimal direct exposure to commodity price fluctuations. The north Louisiana intrastate pipeline operated by this segment serves the Partnership's gathering and processing facilities in the same area and those transactions create a portion of the intersegment revenue shown in the table below.

The contract compression segment provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership's integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and ongoing operation, service, and repair of its compression units, which are modified as necessary to adapt to customers' changing operating conditions. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

The corporate and others segment comprises regulated entities and the Partnership's corporate offices. Revenue in this segment includes the collection of the partial reimbursement of general and administrative costs from HPC.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the gathering and processing and for the transportation segments, is defined as total revenue, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenue minus direct costs, which primarily consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenue in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Results for each income statement period, together with amounts related to balance sheets for each segment are shown below.

	Gathering and Processing	Transportation	Contract Compression	Corporate and Others	Eliminations	Total
			(in thousands)			
External Revenue[1]						
Year ended December 31, 2009	$ 920,650	$ 9,078	$ 148,846	$ 10,923	$ —	$1,089,497
Year ended December 31, 2008	1,685,946	42,400	132,549	2,909	—	1,863,804
Year ended December 31, 2007	1,151,739	36,587	—	1,912	—	1,190,238
Intersegment Revenue[1]						
Year ended December 31, 2009	(8,755)	4,933	4,604	296	(1,078)	—
Year ended December 31, 2008	42,310	11,422	4,573	339	(58,644)	—
Year ended December 31, 2007	26,165	12,391	—	281	(38,837)	—
Cost of Sales[1] [2]						
Year ended December 31, 2009	681,383	2,297	12,422	(65)	3,526	699,563
Year ended December 31, 2008	1,463,851	(13,066)	11,619	—	(54,071)	1,408,333
Year ended December 31, 2007	1,018,721	(3,570)	—	(169)	(38,837)	976,145
Segment Margin[1]						
Year ended December 31, 2009	230,512	11,714	141,028	11,284	(4,604)	389,934
Year ended December 31, 2008	264,405	66,888	125,503	3,248	(4,573)	455,471
Year ended December 31, 2007	159,183	52,548	—	2,362	—	214,093
Operation and Maintenance						
Year ended December 31, 2009	88,520	2,112	45,744	426	(5,976)	130,826
Year ended December 31, 2008	82,689	3,540	49,799	74	(4,473)	131,629
Year ended December 31, 2007	53,496	4,407	—	97	—	58,000
Depreciation and Amortization						
Year ended December 31, 2009	67,583	2,448	36,548	3,314	—	109,893
Year ended December 31, 2008	58,900	14,099	28,448	1,119	—	102,566
Year ended December 31, 2007	40,309	13,457	—	1,308	—	55,074
Income from Unconsolidated Subsidiary						
Year ended December 31, 2009	—	7,886	—	—	—	7,886
Year ended December 31, 2008	—	—	—	—	—	—
Year ended December 31, 2007	—	—	—	—	—	—
Assets						
December 31, 2009	1,046,619	453,120	926,213	107,462	—	2,533,414
December 31, 2008	1,101,906	325,310	881,552	149,871	—	2,458,639
Investment in Unconsolidated Subsidiary						
December 31, 2009	—	453,120	—	—	—	453,120
December 31, 2008	—	—	—	—	—	—
Goodwill						
December 31, 2009	63,232	—	164,882	—	—	228,114
December 31, 2008	63,232	34,244	164,882	—	—	262,358
Expenditures for Long-Lived Assets						
Year ended December 31, 2009	84,097	22,367	83,707	2,912	—	193,083
Year ended December 31, 2008	124,736	59,231	186,063	5,053	—	375,083
Year ended December 31, 2007	112,813	15,658	—	1,313	—	129,784

(1) The December 31, 2008 and 2007 amounts differ from previously reported amounts primarily due to the presentation of intersegment revenue, cost of sales and segment margin elimination amounts in the elimination column as opposed to including these amounts in each respective segment column.

(2) The Partnership identified an $80,000,000 typographical error related to the gathering and processing segment cost of sales for the year ended December 31, 2007. The amount should have been $1,008,517,000 as opposed to $1,088,517,000. However this error did not have an impact to the consolidated cost of sales nor the gathering and processing segment margin for the year ended December 31, 2007. The Partnership corrected this typographical error, together with the revision of the presentation of intersegment cost of sales discussed above in its December 31, 2009 segment information disclosure.

The table below provides a reconciliation of total segment margin to net income (loss) from continuing operations.

	Year Ended December 31, 2009	December 31, 2008	December 31, 2007
		(in thousands)	
Net income (loss) attributable to Regency Energy Partners LP	$ 140,398	$ 101,016	$ (13,836)
Add (deduct):			
Operation and maintenance	130,826	131,629	58,000
General and administrative	57,863	51,323	39,713
(Gain) loss on assets sales	(133,284)	472	1,522
Management services termination fee	—	3,888	—
Transaction expenses	—	1,620	420
Depreciation and amortization	109,893	102,566	55,074
Income from unconsolidated subsidiary	(7,886)	—	—
Interest expense, net	77,996	63,243	52,016
Loss on debt refinancing	—	—	21,200
Other income and deductions, net	15,132	(332)	(1,252)
Income tax (benefit) expense	(1,095)	(266)	931
Net income attributable to noncontrolling interest	91	312	305
Total segment margin	$ 389,934	$ 455,471	$ 214,093

17. Equity-Based Compensation

Common Unit Option and Restricted (Non-Vested) Units. The Partnership's LTIP for the Partnership's employees, directors and consultants covers an aggregate of 2,865,584 common units. Awards under the LTIP have been made since completion of the Partnership's IPO. All outstanding, unvested LTIP awards at the time of the GE EFS Acquisition vested upon the change of control. As a result, the Partnership recorded a one-time charge of $11,928,000 during the year ended December 31, 2007 that was recorded in general and administrative expenses. LTIP awards made subsequent to the GE EFS Acquisition generally vest on the basis of one-fourth of the award each year. Options expire ten years after the grant date. LTIP compensation expense of $5,590,000, $4,318,000, and $15,534,000, is recorded in general and administrative in the statement of operations for the years ended December 31, 2009, 2008, and 2007, respectively.

The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. The Partnership used the simplified method outlined in Staff Accounting Bulletin No. 107 for estimating the exercise behavior of option grantees, given the absence of historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its units have been publicly traded. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The following assumptions apply to the options granted during the year ended December 31, 2007.

	For the Year Ended December 31, 2007
Weighted average expected life (years)	4
Weighted average expected dividend per unit	$ 1.51
Weighted average grant date fair value of options	$ 2.31
Weighted average risk free rate	4.60%
Weighted average expected volatility	16.0%
Weighted average expected forfeiture rate	11.0%

The common unit options activity for the years ended December 31, 2009, 2008, and 2007 is as follows.

2009

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value * (in thousands)
Outstanding at the beginning of period	431,918	$ 21.31		
Granted	—	—		
Exercised	—	—		$ —
Forfeited or expired	(125,267)	20.87		
Outstanding at end of period	306,651	21.50	6.3	184
Exercisable at the end of the period	306,651			184

2008

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period	738,668	$ 21.05		
Granted	—	—		
Exercised	(245,150)	20.55		$ 1,719
Forfeited or expired	(61,600)	21.11		
Outstanding at end of period	431,918	21.31	7.3	—
Exercisable at the end of the period	431,918			—

2007

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period	909,600	$ 21.06		
Granted	21,500	27.18		
Exercised	(149,934)	21.78		$ 1,738
Forfeited or expired	(42,498)	21.85		
Outstanding at end of period	738,668	21.05	8.2	9,104
Exercisable at the end of the period	738,668	21.05		9,104

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

The restricted (non-vested) common unit activity for the years ended December 31, 2009, 2008, and 2007 is as follows.

2009

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	704,050	$ 29.26
Granted	24,500	11.13
Vested	(176,291)	29.78
Forfeited or expired	(88,250)	27.96
Outstanding at the end of period	464,009	28.36

2008

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	397,500	$ 31.62
Granted	477,800	27.99
Vested	(90,500)	31.63
Forfeited or expired	(80,750)	30.66
Outstanding at the end of period	704,050	29.26

2007

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	516,500	$ 21.06
Granted	615,500	30.44
Vested	(684,167)	22.91
Forfeited or expired	(50,333)	27.20
Outstanding at the end of period	397,500	31.62

The Partnership will make distributions to non-vested restricted common units at the same rate and on the same dates as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time; non-vested restricted units are subject to forfeitures on termination of employment. The Partnership expects to recognize $9,517,000 of compensation expense related to the grants under LTIP primarily over the next 1.91 years.

Phantom Units. During 2009, the Partnership awarded 308,200 phantom units to senior management and certain key employees. These phantom units are in substance two grants composed of (1) service condition grants (also defined as “time-based grants” in the LTIP plan document) with graded vesting occurring on March 15 of each of the following three years; and (2) market condition grants (also defined as “performance-based grants” in the LTIP plan document) with cliff vesting based upon the Partnership’s relative ranking in total unitholder return among 20 peer companies, which peer companies are disclosed in Item 11 of the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2009. At the end of the measurement period (March 15, 2012) for the market condition grants, the phantom units will convert to common units in a ratio ranging from 0 to 150 percent. Upon a change in control, the market condition based grants will convert to common units at 150 percent and the service condition grants will convert to common on a one-for-one basis. For both the service condition grants and the market condition grants, distributions will be accumulated from the grant date and paid upon vesting at the same rate as the common units.

In determining the grant date fair value, the grant date closing price of the Partnership’s common units on NASDAQ was used for the service condition awards. For the market condition awards, a Monte Carlo simulation was performed which incorporated variables mainly including the unit price volatility and the grant-date closing price of the Partnership's common units on NASDAQ.

The Partnership expects to recognize $1,753,000 of compensation expense related to non-vested phantom units over a period of 2.4 years. During the year ended December 31, 2009, the Partnership recognized $418,000 of expense, which was reflected in general and administrative expense in the statement of operations.

The following table presents phantom unit activity for the year ended December 31, 2009.

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	—	$ —
Service condition grants	133,480	13.43
Market condition grants	174,720	4.64
Vested service condition	—	—
Vested market condition	—	—
Forfeited service condition	(2,600)	12.46
Forfeited market condition	(3,900)	4.49
Total outstanding at end of period	301,700	8.63

18. Subsequent Events

On January 26, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner's two percent interest in the Partnership, and an aggregate distribution of approximately $728,000, with respect to incentive distribution rights, that was paid on February 12, 2010 to unitholders of record at the close of business on February 5, 2010.

19. Quarterly Financial Data (Unaudited)

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) Attributable to Regency Energy Partners LP	Basic Earnings per Common and Subordinated Unit	Diluted Earnings per Common and Subordinated Unit	Basic and Diluted Earnings per Class D Common Unit
			(in thousands except earnings per unit)			
2009						
March 31	$290,125	$162,373	$ 148,389[1]	$ 1.85	$ 1.78	$ 0.11
June 30	253,542	23,207	5,890	0.07	0.06	—
September 30	250,582	21,831	(10,504)	(0.16)	(0.16)	—
December 31	295,248	17,225	(3,377)	(0.07)	(0.07)	—
2008						
March 31[2]	$405,235	$ 25,877	$ 10,348	$ 0.13	$ 0.13	$ 0.21
June 30	546,705	26,512	9,972	0.12	0.12	0.26
September 30[2]	547,175	64,956	48,907	0.64	0.61	0.26
December 31	364,689	46,628	31,789	0.39	0.38	0.26

(1) In March 2009, the Partnership contributed RIG to HPC, recognized a gain of $133,451,000 on the transaction. See Note 5 for further information.

(2) The operating income amount and basic and diluted earnings per Class D Common Unit disclosed above differs immaterially from the amount disclosed in the Form 10-Q.

As disclosed in Note 1, on May 26, 2010 GP Seller sold all of the outstanding membership interests of the Partnership’s General Partner to ETE, effecting a change in control of the Partnership. In connection with this transaction, the Partnership’s assets and liabilities were required to be adjusted to fair value at the acquisition date by application of “push-down” accounting. As a result, the Partnership’s unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as “Predecessor” and (2) the period from May 26, 2010 forward, identified as “Successor”.

Regency Energy Partners LP

Condensed Consolidated Balance Sheets
(in thousands except unit data)

	Successor June 30, 2010 (unaudited)	Predecessor December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,296	$ 9,827
Restricted cash	1,011	1,511
Trade accounts receivable, net of allowance of $475 and $1,130	22,801	30,433
Accrued revenues	76,272	95,240
Related party receivables	33,444	6,222
Derivative assets	19,833	24,987
Other current assets	8,420	10,556
Total current assets	166,077	178,776
Property, Plant and Equipment:		
Gathering and transmission systems	488,336	465,959
Compression equipment	785,685	823,060
Gas plants and buildings	131,537	159,596
Other property, plant and equipment	101,046	162,433
Construction-in-progress	125,528	95,547
Total property, plant and equipment	1,632,132	1,706,595
Less accumulated depreciation	(8,740)	(250,160)
Property, plant and equipment, net	1,623,392	1,456,435
Other Assets:		
Investment in unconsolidated subsidiaries	1,369,921	453,120
Long-term derivative assets	1,241	207
Other, net of accumulated amortization of debt issuance costs of $564 and $10,743	34,206	19,468
Total other assets	1,405,368	472,795
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $2,159 and $33,929	666,781	197,294
Goodwill	733,674	228,114
Total intangible assets and goodwill	1,400,455	425,408
TOTAL ASSETS	$4,595,292	$2,533,414
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 43,513	$ 44,912
Accrued cost of gas and liquids	75,619	76,657
Related party payables	4,417	2,312
Deferred revenues, including related party amounts of $0 and $338	11,244	11,292
Derivative liabilities	3,576	12,256
Escrow payable	1,011	1,511
Other current liabilities, including related party amounts of $630 and $0	14,985	12,368
Total current liabilities	154,365	161,308
Long-term derivative liabilities	52,609	48,903
Other long-term liabilities	14,249	14,183
Long-term debt, net	1,276,640	1,014,299
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount of $83,891 and $83,891	70,850	51,711
Partners' Capital and Noncontrolling Interest:		
Common units (120,676,002 and 94,243,886 units authorized; 119,614,719 and 93,188,353 units issued and outstanding at June 30, 2010 and December 31, 2009)	2,659,907	1,211,605
General partner interest	335,193	19,249
Accumulated other comprehensive loss	—	(1,994)
Noncontrolling interest	31,479	14,150
Total partners' capital and noncontrolling interest	3,026,579	1,243,010
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$4,595,292	$2,533,414

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Operations
Unaudited
(in thousands except unit data and per unit data)

	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010	Three Months Ended June 30, 2009
REVENUES			
Gas sales, including related party amounts of $447, $0, and $0	$ 48,103	$ 89,170	$ 106,897
NGL sales including related party amounts of $18,054, $0, and $0	28,766	69,033	57,676
Gathering, transportation and other fees, including related party amounts of $2,086, $3,680, and $2,239	22,884	45,733	69,231
Net realized and unrealized (loss) gain from derivatives	(130)	223	12,515
Other	3,357	7,336	7,223
Total revenues	102,980	211,495	253,542
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $2,281, $3,198, and $1,453	74,081	147,262	157,347
Operation and maintenance	11,942	21,430	31,974
General and administrative, including related party amounts of $833, $0, and $0	7,104	21,809	14,127
Loss on asset sales, net	10	19	651
Depreciation and amortization	10,995	18,609	26,236
Total operating costs and expenses	104,132	209,129	230,335
OPERATING (LOSS) INCOME	(1,152)	2,366	23,207
Income from unconsolidated subsidiaries	8,121	7,959	1,587
Interest expense, net	(8,109)	(14,114)	(19,568)
Other income and deductions, net	(3,510)	(624)	214
(LOSS) INCOME BEFORE INCOME TAXES	(4,650)	(4,413)	5,440
Income tax expense (benefit)	245	83	(515)
NET (LOSS) INCOME	$ (4,895)	$ (4,496)	$ 5,955
Net income attributable to noncontrolling interest	(29)	(244)	(65)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ (4,924)	$ (4,740)	$ 5,890
Amounts attributable to Series A convertible redeemable preferred units	668	1,335	—
General partner's interest, including IDR	803	—	741
Amount allocated to non-vested common units	—	—	(137)
Limited partners' interest	$ (6,395)	$ (6,075)	$ 5,286
Basic and Diluted (loss) earnings per unit:			
Amount allocated to common units	$ (6,395)	$ (6,075)	$ 5,286
Weighted average number of common units outstanding	119,600,652	92,832,219	80,550,149
Basic (loss) income per common unit	$ (0.05)	$ (0.07)	$ 0.07
Diluted (loss) income per common unit	$ (0.05)	$ (0.07)	$ 0.06
Distributions paid per unit	$ 0.445	$ —	$ 0.445

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Operations
Unaudited
(in thousands except unit data and per unit data)

	Successor Period from Acquisition (May 26, 2010) to June 30, 2010	Predecessor Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
REVENUES			
Gas sales, including related party amounts of $447, $0, and $0	$ 48,103	$ 232,063	$ 254,793
NGL sales including related party amounts of $18,054, $0, and $0	28,766	166,362	107,261
Gathering, transportation and other fees, including related party amounts of $2,086, $12,200 and $3,376	22,884	116,061	142,079
Net realized and unrealized (loss) gain from derivatives	(130)	(716)	26,970
Other	3,357	15,477	12,417
Total revenues	102,980	529,247	543,520
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $2,281, $6,564 and $1,700	74,081	371,871	339,875
Operation and maintenance	11,942	53,841	68,016
General and administrative, including related party amounts of $833, $0, and $0	7,104	37,212	29,205
Loss (gain) on asset sales, net	10	303	(133,280)
Depreciation and amortization	10,995	46,084	54,125
Total operating costs and expenses	104,132	509,311	357,941
OPERATING (LOSS) INCOME	(1,152)	19,936	185,579
Income from unconsolidated subsidiaries	8,121	15,872	1,923
Interest expense, net	(8,109)	(36,459)	(33,795)
Other income and deductions, net	(3,510)	(3,891)	256
(LOSS) INCOME BEFORE INCOME TAXES	(4,650)	(4,542)	153,963
Income tax expense (benefit)	245	404	(416)
NET (LOSS) INCOME	$ (4,895)	$ (4,946)	$ 154,379
Net income attributable to noncontrolling interest	(29)	(406)	(100)
NET (LOSS) INCOME ATTRIBUTABLE TO REGENCY ENERGY PARTNERS LP	$ (4,924)	$ (5,352)	$ 154,279
Amounts attributable to Series A convertible redeemable preferred units	668	3,336	—
General partner's interest, including IDR	803	662	4,274
Amount allocated to non-vested common units	—	(79)	1,217
Beneficial conversion feature for Class D common units	—	—	820
Limited partners' interest	$ (6,395)	$ (9,271)	$ 147,968
Basic and Diluted (loss) earnings per unit:			
Amount allocated to common units	$ (6,395)	$ (9,271)	$ 147,968
Weighted average number of common units outstanding	119,600,652	92,788,319	78,920,074
Basic (loss) income per common unit	$ (0.05)	$ (0.10)	$ 1.87
Diluted (loss) income per common unit	$ (0.05)	$ (0.10)	$ 1.85
Distributions paid per unit	$ 0.445	$ 0.445	$ 0.89
Amount allocated to Class D common units	$ —	$ —	$ 820
Total number of Class D common units outstanding	—	—	7,276,506
Income per Class D common unit due to beneficial conversion feature	$ —	$ —	$ 0.11
Distributions paid per unit	$ —	$ —	$ —

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Comprehensive (Loss) Income
Unaudited
(in thousands)

	Three Months Ended June 30, 2010 and 2009		
	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010	Three Months Ended June 30, 2009
Net (loss) income	$ (4,895)	$ (4,496)	$ 5,955
Net hedging amounts reclassified to earnings	—	(512)	(13,644)
Net change in fair value of cash flow hedges	—	8,649	(14,622)
Comprehensive (loss) income	$ (4,895)	$ 3,641	$ (22,311)
Comprehensive income attributable to noncontrolling interest	29	244	65
Comprehensive (loss) income attributable to Regency Energy Partners LP	$ (4,924)	$ 3,397	$ (22,376)

	Six Months Ended June 30, 2010 and 2009		
	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
Net (loss) income	$ (4,895)	$ (4,946)	$ 154,379
Net hedging amounts reclassified to earnings	—	2,145	(27,894)
Net change in fair value of cash flow hedges	—	18,486	(9,242)
Comprehensive (loss) income	$ (4,895)	$ 15,685	$ 117,243
Comprehensive income attributable to noncontrolling interest	29	406	100
Comprehensive (loss) income attributable to Regency Energy Partners LP	$ (4,924)	$ 15,279	$ 117,143

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Cash Flows
Unaudited
(in thousands)

	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
OPERATING ACTIVITIES			
Net (loss) income	$ (4,895)	$ (4,946)	$ 154,379
Adjustments to reconcile net (loss) income to net cash flows provided by (used in) operating activities:			
Depreciation and amortization, including debt issuance cost amortization	11,330	49,363	56,750
Write-off of debt issuance costs	—	1,780	—
Income from unconsolidated subsidiaries	(8,121)	(15,872)	(1,923)
Derivative valuation changes	6,921	12,004	(6,293)
Loss (gain) on asset sales, net	10	303	(133,280)
Unit-based compensation expenses	137	12,070	2,750
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues, and related party receivables	13,843	(11,272)	38,073
Other current assets	585	2,516	3,728
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(15,460)	8,649	(39,185)
Other current liabilities	(20,497)	22,614	(7,396)
Distributions received from unconsolidated subsidiaries	—	12,446	1,900
Other assets and liabilities	(60)	(234)	(232)
Net cash flows (used in) provided by operating activities	(16,207)	89,421	69,271
INVESTING ACTIVITIES			
Capital expenditures	(20,875)	(63,787)	(119,185)
Capital contribution to unconsolidated subsidiaries	(38,922)	(20,210)	—
Acquisitions, net of cash received	12,848	(75,114)	—
Proceeds from asset sales	14	10,661	83,182
Net cash flows (used in) investing activities	(46,935)	(148,450)	(36,003)
FINANCING ACTIVITIES			
Net borrowings (repayments) under revolving credit facility	37,000	199,008	(177,249)
Proceeds from issuance of senior notes, net of discount	—	—	236,240
Debt issuance costs	(132)	(15,728)	(11,939)
Partner contributions	7,436	—	—
Partner distributions	—	(86,078)	(71,644)
Acquisition of assets between entities under common control in excess of historical cost	—	(16,973)	—
Distributions to noncontrolling interest	—	(1,135)	—
Proceeds from option exercises	150	120	—
Equity issuance costs	—	(89)	—
Distributions to redeemable convertible preferred units	—	(1,945)	—
Tax withholding on unit-based vesting	—	(4,994)	—
Net cash flows provided by (used in) financing activities	44,454	72,186	(24,592)
Net change in cash and cash equivalents	(18,688)	13,157	8,676
Cash and cash equivalents at beginning of period	22,984	9,827	599
Cash and cash equivalents at end of period	$ 4,296	$ 22,984	$ 9,275
Supplemental cash flow information:			
Non-cash capital expenditures	$ 16,159	$ 18,051	$ 9,480
Issuance of common units for an acquisition	584,436	—	—
Deemed contribution from acquisition of assets between entities under common control	17,152	—	—
Release of escrow payable from restricted cash	—	500	—
Contribution of fixed assets, goodwill and working capital to HPC	—	—	263,921
Contribution receivable	12,288	—	—

See accompanying notes to condensed consolidated financial statements

Regency Energy Partners LP

Condensed Consolidated Statements of Partners' Capital and Noncontrolling Interest

Unaudited

(in thousands except unit data)

	Regency Energy Partners LP					
	Units					
	Common	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Predecessor						
Balance - December 31, 2009	93,188,353	$1,211,605	$ 19,249	$ (1,994)	$ 14,150	$1,243,010
Issuance of common units under LTIP, net of forfeitures and tax withholding	152,075	(4,994)	—	—	—	(4,994)
Issuance of common units, net of costs	—	(89)	—	—	—	(89)
Exercise of common unit options	—	120	—	—	—	120
Unit-based compensation expenses	—	12,070	—	—	—	12,070
Accrued distributions to phantom units	—	(473)	—	—	—	(473)
Acquisition of assets between entities under common control in excess of historical cost	—	—	(16,973)	—	—	(16,973)
Partner distributions	—	(84,504)	(1,574)	—	—	(86,078)
Distributions to noncontrolling interest	—	—	—	—	(1,135)	(1,135)
Net (loss) income	—	(6,014)	662	—	406	(4,946)
Distributions to Series A convertible redeemable preferred units	—	(1,906)	(39)	—	—	(1,945)
Accretion of Series A convertible redeemable preferred units	—	(55)	—	—	—	(55)
Net cash flow hedge amounts reclassified to earnings	—	—	—	2,145	—	2,145
Net change in fair value of cash flow hedges	—	—	—	18,486	—	18,486
Balance - May 25, 2010	93,340,428	$1,125,760	$ 1,325	$ 18,637	$ 13,421	$1,159,143

	Regency Energy Partners LP					
	Units					
	Common	Common Unitholders	General Partner Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Successor						
Balance - May 26, 2010	93,340,428	$2,073,532	$304,950	$ —	$ 31,450	$2,409,932
Issuance of common units, net of costs	26,266,791	584,436	—	—	—	584,436
Exercise of common unit options	7,500	150	—	—	—	150
Unit-based compensation expenses	—	137	—	—	—	137
Acquisition of assets between entities under common control below historical cost	—	—	17,152	—	—	17,152
Partner contributions	—	7,436	12,288	—	—	19,724
Net (loss) income	—	(5,727)	803	—	29	(4,895)
Accretion of Series A convertible redeemable preferred units	—	(57)	—	—	—	(57)
Balance - June 30, 2010	119,614,719	$2,659,907	$335,193	$ —	$ 31,479	$3,026,579

See accompanying notes to condensed consolidated financial statements

1. Organization and Summary of Significant Accounting Policies

Organization. The unaudited condensed consolidated financial statements presented herein contain the results of Regency Energy Partners LP (the "Partnership") and its subsidiaries. The Partnership and its subsidiaries are engaged in the business of gathering, processing and transporting of natural gas and NGLs as well as providing contract compression services.

Basis of Presentation. On May 26, 2010, GP Seller completed the sale of all of the outstanding membership interests of the General Partner pursuant to a Purchase Agreement (the "Purchase Agreement") among itself, ETE and ETE GP (the "ETE Acquisition"). Prior to the closing of the Purchase Agreement, GP Seller, an affiliate of GE EFS, owned all the outstanding limited partners' interests in the General Partner, which is the sole general partner of the Partnership, and the entire member's interest in the Managing General Partner, which is the sole general partner of the General Partner and, by virtue of that position, controlled the Partnership. Control of the Partnership transferred from GE EFS to ETE as a result of the ETE Acquisition. In connection with this transaction, the Partnership's assets and liabilities were required to be adjusted to fair value on the closing date (May 26, 2010) by application of "push-down" accounting (the "Push-down Adjustments"). Total enterprise value of the Partnership as of May 26, 2010 was $3,783,680,000, giving effect to the transaction and the associated Push-down Adjustments, which is calculated below:

	(in thousands)
Fair value of limited partners interest, based on the number of outstanding Partnership common units and the trading price on May 26, 2010	$ 2,073,532
Fair value of consideration paid for general partner interest	304,950
Noncontrolling interest	31,450
Series A convertible redeemable preferred units	70,793
Fair value of long-term debt	1,239,863
Other long-term liabilities	63,092
Enterprise value	$ 3,783,680

The Partnership has developed the preliminary amount of the fair value of its assets and liabilities. Management is reviewing the valuation and confirming results to determine the final purchase price allocation. The Partnership allocated the enterprise value to the following assets and liabilities based on their respective estimated fair values as of May 26, 2010:

	At May 26, 2010 (in thousands)
Working capital	$ (3,286)
Gathering and transmission systems	487,792
Compression equipment	779,634
Gas plants and buildings	131,537
Other property, plant and equipment	100,267
Construction-in-progress	114,146
Other long-term assets	36,839
Investment in unconsolidated subsidiary	734,137
Intangible assets	668,940
Goodwill	733,674
	$ 3,783,680

Due to the Push-down Adjustments, the Partnership's unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as "Predecessor" and (2) the period from May 26, 2010 forward, identified as "Successor".

The unaudited financial information included in this Form 10-Q has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with GAAP. All inter-company items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the SEC.

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP and, of necessity, include the use of estimates and assumptions by management. Actual results could differ from these estimates.

Intangible Assets. Intangible assets, net consist of the following.

Predecessor	Contracts	Customer Relations	Trade Names (in thousands)	Permits and Licenses	Total
Balance at December 31, 2009	$126,332	$ 35,362	$ 30,508	$ 5,092	$197,294
Amortization	(3,322)	(817)	(975)	(214)	(5,328)
Balance at May 25, 2010	$123,010	$ 34,545	$ 29,533	$ 4,878	$191,966

Successor	Customer Relations	Trade Names (in thousands)	Total
Balance at May 26, 2010	$604,840	$ 64,100	$ 668,940
Amortization	(1,905)	(254)	(2,159)
Balance at June 30, 2010	$602,935	$ 63,846	$ 666,781

As of June 30, 2010, customer relations and trade names are amortized over 30 and 20 years, respectively. The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2010 (remaining)	$ 11,606
2011	23,211
2012	23,211
2013	23,211
2014	23,211

Recently Issued Accounting Standards. In June 2009, the FASB issued guidance that significantly changed the consolidation model for variable interest entities. The guidance is effective for annual reporting periods that begin after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership determined that this guidance had no impact on its financial position, results of operations or cash flows upon adoption on January 1, 2010.

In January 2010, the FASB issued guidance requiring improved disclosure of transfers in and out of Levels 1 and 2 for an entity's fair value measurements, such requirement becoming effective for interim and annual periods beginning after December 15, 2009. Further, additional disclosure of activities such as purchases, sales, issuances and settlements of items relying on Level 3 inputs will be required, such requirements becoming effective for interim and annual periods beginning after December 15, 2010. The Partnership determined that this guidance with respect to Levels 1, 2 and 3 had no impact on its financial position, results of operations or cash flows upon adoption.

In February 2010, the FASB clarified the type of embedded credit derivative that is exempt from embedded derivative bifurcation requirements. The Partnership evaluated the impact of this update on its accounting for embedded derivatives and determined that it had no impact on its financial position, results of operations or cash flows.

2. (Loss) Income per Limited Partner Unit

On September 2, 2009, the Partnership issued 4,371,586 Series A Convertible Redeemable Preferred Units ("Series A Preferred Units"). The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010. Distributions for the quarters ended September 30, 2009 and December 31, 2009 were accrued, effectively increasing the conversion value of the Series A Preferred Units. Distributions are cumulative, and must be paid before any distributions to the general partner and common unitholders. For the purpose of calculating income per limited partner unit, any form of distributions, whether paid or not, as well as the accretion of the Series A Preferred Units, are treated as a reduction in net income (loss) available to the general partner and limited partner interests.

The following table provides a reconciliation of the numerator and denominator of the basic and diluted earnings per common unit computations for the three and six months ended June 30, 2010 and 2009.

	Three Months Ended June 30, 2010 and 2009								
	Successor			Predecessor					
	Period from Acquisition (May 26, 2010) to June 30, 2010			Period from April 1, 2010 to Disposition (May 25, 2010)			Three Months Ended June 30, 2009		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)			(in thousands except unit and per unit data)					
Basic (Loss) Earnings per Unit									
Limited partners' interests	$ (6,395)	119,600,652	$ (0.05)	$ (6,075)	92,832,219	$ (0.07)	$ 5,286	80,550,149	$ 0.07
Effect of Dilutive Securities									
Restricted (non-vested) common units	—	—		—	—		(137)	621,337	
Diluted (Loss) Earnings per Unit	$ (6,395)	119,600,652	$ (0.05)	$ (6,075)	92,832,219	$ (0.07)	$ 5,149	81,171,486	$ 0.06

	Six Months Ended June 30, 2010 and 2009								
	Successor			Predecessor					
	Period from Acquisition (May 26, 2010) to June 30, 2010			Period from January 1, 2010 to Disposition (May 25, 2010)			Six Months Ended June 30, 2009		
	Loss (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount	Income (Numerator)	Units (Denominator)	Per-Unit Amount
	(in thousands except unit and per unit data)			(in thousands except unit and per unit data)					
Basic (Loss) Earnings per Unit									
Limited partners' interest	$ (6,395)	119,600,652	$ (0.05)	$ (9,271)	92,788,319	$ (0.10)	$ 147,968	78,920,074	$ 1.87
Effect of Dilutive Securities									
Restricted (non-vested) common units	—	—		—	—		1,217	652,740	
Class D common units	—	—		—	—		820	1,608,068	
Diluted (Loss) Earnings per Unit	$ (6,395)	119,600,652	$ (0.05)	$ (9,271)	92,788,319	$ (0.10)	$ 150,005	81,180,882	$ 1.85

The following table shows the weighted average outstanding amount of securities that could potentially dilute earnings per unit in the future that were not included in the computation of diluted earnings per unit because to do so would have been antidilutive.

	Successor	Predecessor			
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to Disposition (May 25, 2010)	Three Months Ended June 30, 2009	Period from January 1, 2010 to Disposition (May 25, 2010)	Six Months Ended June 30, 2009
Restricted (non-vested) common units	—	356,954	—	396,918	—
Phantom units *	322,750	351,345	332,860	369,346	332,860
Common unit options	290,150	290,150	372,768	298,400	376,518
Convertible redeemable preferred units	4,584,192	4,584,192	—	4,584,192	—

* Amount disclosed assumes maximum conversion rate for market condition awards.

3. Acquisitions

On April 30, 2010, the Partnership purchased an additional 6.99 percent general partner interest in HPC from EFS Haynesville, bringing its total general partner interest in HPC to 49.99 percent. The purchase price of $92,087,000 was funded by borrowings under the Partnership's revolving credit facility. Because this transaction occurred between two entities under common control, partners' capital was decreased by $16,973,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount of $75,114,000.

On May 26, 2010, the Partnership purchased a 49.9 percent interest in MEP from ETE. The Partnership issued 26,266,791 common units to ETE, valued at $584,436,000, and received a working capital adjustment of $12,848,000 from ETE that was recorded as an adjustment to investment in unconsolidated subsidiaries. Because this transaction occurred between two entities under common control, partners' capital was increased by $17,152,000, which represented a deemed contribution of the excess carrying amount of ETE's investment of $588,740,000 over the purchase price. MEP is a 500 mile natural gas pipeline system that extends from the southeast corner of Oklahoma, across northeast Texas, northern Louisiana, central Mississippi and into Alabama. In June 2010, the Partnership made an additional capital contribution of $38,922,000 to MEP.

The following unaudited pro forma financial information has been prepared as if the transactions involving the purchase of 6.99 percent general partner interest in HPC, purchase of the 49.9 percent interest in MEP, together with the Push-down Adjustments described in Note 1 occurred as of the beginning of the earliest period presented. Such unaudited pro forma financial information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the dates referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the			
	Period from April 1, 2010 to May 25, 2010	Three Months Ended June 30, 2009	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
	(in thousands except unit and per unit data)			
Total revenues	$ 211,495	$ 253,542	$ 529,247	$ 531,547
Net (loss) income attributable to Regency Energy Partners LP	$ (4,361)	$ (2,581)	$ (6,108)	$ 133,911
Amounts attributable to Series A convertible redeemable preferred units	1,335	—	3,336	—
General partner's interest, including IDR	801	773	1,641	4,270
Amount allocated to non-vested common units	—	(196)	(80)	711
Beneficial conversion feature for Class D common units	—	—	—	820
Limited partners' interest	$ (6,497)	$ (3,158)	$ (11,005)	$ 128,110
Basic and Diluted earnings (loss) per unit:				
Amount allocated to common units	$ (6,497)	$ (3,158)	$ (11,005)	$ 128,110
Weighted average number of common units outstanding	119,099,010	106,816,940	119,055,110	105,186,865
Basic (loss) income per common unit	$ (0.05)	$ (0.03)	$ (0.09)	$ 1.22
Diluted (loss) income per common unit	$ (0.05)	$ (0.03)	$ (0.09)	$ 1.21
Distributions paid per unit	$ 0.445	$ 0.445	$ 0.445	$ 0.890
Amount allocated to Class D common units	$ —	$ —	$ —	$ 820
Total number of Class D common units outstanding	—	—	—	7,276,506
Income per Class D common unit due to beneficial conversion feature	$ —	$ —	$ —	$ 0.11
Distributions per unit	$ —	$ —	$ —	$ —

4. Investment in Unconsolidated Subsidiaries

Investment in HPC. HPC was established in March 2009 and as of June 30, 2010, the Partnership owns 49.99 percent interest in HPC. Following table summarizes the changes in the Partnership's investment in HPC.

	Successor	Predecessor			
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to Disposition (May 25, 2010)	Three Months Ended June 30, 2009	Period from January 1, 2010 to Disposition (May 25, 2010)	Six Months Ended June 30, 2009
	(in thousands)	(in thousands)			
Contributions to HPC	$ —	$ 20,210	$ —	$ 20,210	$ 400,000
Distributions received from HPC	—	8,920	1,900	12,446	1,900
Partnership's share of HPC's net income	4,460	7,959	1,587	15,872	1,923

As discussed in Note 1, the Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $143,757,000 was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated subsidiaries over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $38,510,000 could not be attributed to a specific asset and therefore will not be amortized in future periods. For the period from May 26, 2010 to June 30, 2010, the Partnership recorded $365,000 as a reduction of income from unconsolidated subsidiaries due to the amortization of the excess fair value of long-lived assets.

The summarized financial information of HPC is disclosed below.

RIGS Haynesville Partnership Co.
Condensed Consolidated Balance Sheets
(in thousands)

	June 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Total current assets	$ 48,383	$ 39,239
Restricted cash, non-current	43,314	33,595
Property, plant and equipment, net	888,542	861,570
Total other assets	149,065	149,755
TOTAL ASSETS	$1,129,304	$ 1,084,159
LIABILITIES & PARTNERS' CAPITAL		
Total current liabilities	$ 17,273	$ 30,967
Partners' capital	1,112,031	1,053,192
TOTAL LIABILITIES & PARTNERS' CAPITAL	$1,129,304	$ 1,084,159

RIGS Haynesville Partnership Co.
Condensed Consolidated Income Statements
(in thousands)

	For the Three Months Ended June 30,		For the Six Months Ended June 30, 2010	From Inception (March 18, 2009) to June 30, 2009
	2010	2009		
	(Unaudited)		(Unaudited)	
Total revenues	$44,375	$11,707	$ 79,564	$ 13,533
Total operating costs and expenses	18,425	8,038	35,148	9,084
OPERATING INCOME	25,950	3,669	44,416	4,449
Interest expense	(99)	—	(201)	—
Other income and deductions, net	20	508	59	612
NET INCOME	$25,871	$ 4,177	$ 44,274	$ 5,061

Investment in MEP. On May 26, 2010, the Partnership purchased a 49.9 interest in the MEP from ETE. In June 2010, the Partnership made an additional capital contribution of $38,922,000 to MEP. During the period from May 26, 2010 to June 30, 2010, the Partnership recognized $4,026,000 in income from unconsolidated subsidiaries for its ownership interest.

The summarized financial information of MEP is disclosed below.

Midcontinent Express Pipeline LLC
Condensed Balance Sheet
(in thousands)

	June 30, 2010 (Unaudited)
ASSETS	
Total current assets	$ 32,987
Property, plant and equipment, net	2,225,383
Total other assets	5,588
TOTAL ASSETS	$2,263,958
LIABILITIES & PARTNERS' CAPITAL	
Total current liabilities	$ 92,795
Long-term debt	800,000
Partners' capital	1,371,163
TOTAL LIABILITIES & PARTNERS' CAPITAL	$2,263,958

Midcontinent Express Pipeline LLC
Condensed Income Statement
(in thousands)

	Month Ended June 30, 2010 (Unaudited)
Total revenues	$ 21,269
Total operating costs and expenses	9,770
OPERATING INCOME	11,499
Interest expense, net	(3,431)
NET INCOME	$ 8,068

5. Derivative Instruments

Policies. The Partnership has established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Risk Management Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operation. The prices of these commodities are impacted by changes in the supply and demand as well as market focus. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. Speculative positions with derivative contracts are prohibited under the Partnership's policies.

On May 26, 2010, all of the Partnership's outstanding commodity swaps that were previously accounted for as cash flow hedges were de-designated and are currently accounted for under the mark-to-market method of accounting.

The Partnership executes natural gas, NGLs' and WTI trades on a periodic basis to hedge its anticipated equity exposure. Subsequent to June 30, 2010, the Partnership has executed additional NGL swaps to hedge its 2011 and 2012 price exposure.

The Partnership has executed swap contracts settled against NGLs (ethane, propane, butane and natural gasoline), condensate and natural gas market prices for expected equity exposure in the approximate percentages set forth.

	As of June 30, 2010			As of August 8, 2010		
	2010	2011	2012	2010	2011	2012
NGLs	87%	52%	0%	87%	67%	6%
Condensate	96%	74%	7%	96%	74%	7%
Natural gas	74%	42%	0%	74%	42%	0%

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of June 30, 2010, the Partnership had $655,650,000 of outstanding borrowings exposed to variable interest rate risk. The Partnership's $300,000,000 interest rate swaps expired in March 2010. In April 2010, the Partnership entered into additional two-year interest rate swaps related to $250,000,000 of borrowings under its revolving credit facility, effectively locking the base rate, exclusive of applicable margins, for these borrowings at 1.325 percent through April 2012.

Credit Risk. The Partnership's resale of natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances extension of credit is backed by adequate collateral such as a letter of credit or parental guarantee.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives. The Partnership has entered into Master International Swap Dealers Association ("ISDA") Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties fail to perform under existing swap contracts, the Partnership's maximum loss would be $21,346,000, which would be reduced by $2,824,000 due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the condensed consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustment, as of June 30, 2010 and December 31, 2009 are detailed below.

	Assets		Liabilities	
	June 30, 2010 (unaudited)	December 31, 2009	June 30, 2010 (unaudited)	December 31, 2009
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$ —	$ —	$ —	$ 1,064
Commodity contracts	—	9,521	—	11,161
Long-term amounts				
Commodity contracts	—	207	—	931
Total cash flow hedging instruments	—	9,728	—	13,156
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	19,833	15,466	2,052	31
Interest rate contracts	—	—	1,524	—
Long-term amounts				
Commodity contracts	1,241	—	15	3,378
Interest rate contracts	—	—	355	
Embedded derivatives in Series A Preferred Units	—	—	52,239	44,594
Total derivatives not designated as cash flow hedges	21,074	15,466	56,185	48,003
Total derivatives	$ 21,074	$ 25,194	$ 56,185	$ 61,159

The following tables detail the effect of the Partnership's derivative assets and liabilities in the consolidated statement of operations for the period presented.

		Successor	Predecessor	
		Period from May 26, 2010 through June 30, 2010	Period from April 1, 2010 through May 25, 2010	For the Three Months Ended June 30, 2009
		(in thousands)	(in thousands)	
			Change in Value Recognized in OCI on Derivatives (Effective Portion)	
Derivatives in cash flow hedging relationships:				
Commodity derivatives		—	7,428	(13,946)
Interest rate swap derivatives		—	—	(676)
		—	7,428	(14,622)
			Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
	Location of Gain (Loss) Recognized in Income			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(709)	15,546
Interest rate swap derivatives	Interest expense	—	—	(1,515)
		—	(709)	14,031
			Amount of Gain/(Loss) Recognized in Income on Ineffective Portion	
	Location of Gain (Loss) Recognized in Income			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(301)	1,616
Interest rate swap derivatives	Interest expense	—	—	—
		—	(301)	1,616
			Amount of Gain/(Loss) from Dedesignation Amortized from AOCI into Income	
	Location of Gain (Loss) Recognized in Income			
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	—	1,221	(387)
Interest rate swap derivatives	Interest expense	—	—	—
		—	1,221	(387)
			Amount of Gain/(Loss) Recognized in Income on Derivatives	
	Location of Gain (Loss) Recognized in Income			
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	(824)	12	(5,690)
Interest rate swap derivatives	Interest expense	(1,715)	(824)	—
Embedded derivative	Other income & deductions	(3,606)	(654)	—
		(6,145)	(1,466)	(5,690)

		Successor	Predecessor	
		Period from May 26, 2010 through June 30, 2010	Period from January 1, 2010 through May 25, 2010	For the Six Months Ended June 30, 2009
		(in thousands)		(in thousands)
		Change in Value Recognized in OCI on Derivatives (Effective Portion)		
Derivatives in cash flow hedging relationships:				
Commodity derivatives		—	14,371	(7,728)
Interest rate swap derivatives		—	—	(1,514)
		—	14,371	(9,242)
		Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)		
	Location of Gain (Loss) Recognized in Income			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(5,200)	32,065
Interest rate swap derivatives	Interest expense	—	(1,060)	(2,987)
		—	(6,260)	29,078
		Amount of Gain/(Loss) Recognized in Income on Ineffective Portion		
	Location of Gain (Loss) Recognized in Income			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(799)	2,231
Interest rate swap derivatives	Interest expense	—	—	—
		—	(799)	2,231
		Amount of Gain/(Loss) from Dedesignation Amortized from AOCI into Income		
	Location of Gain (Loss) Recognized in Income			
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	—	4,115	(1,184)
Interest rate swap derivatives	Interest expense	—	—	—
		—	4,115	(1,184)
		Amount of Gain/(Loss) Recognized in Income on Derivatives		
	Location of Gain (Loss) Recognized in Income			
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	(824)	1,247	(7,092)
Interest rate swap derivatives	Interest expense	(1,715)	(824)	—
Embedded derivative	Other income & deductions	(3,606)	(4,039)	—
		(6,145)	(3,616)	(7,092)

6. Long-term Debt

The following table provides information on the Partnership's long-term debt.

	June 30, 2010	December 31, 2009
	(in thousands)	
Senior notes	$ 620,990	$ 594,657
Revolving loans	655,650	419,642
Total	1,276,640	1,014,299
Less: current portion	—	—
Long-term debt	$1,276,640	$ 1,014,299
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded commitments	—	(10,675)
Revolving loans	(655,650)	(419,642)
Letters of credit	(17,032)	(16,257)
Total available	$ 227,318	$ 453,426

Long-term debt maturities as of June 30, 2010 for each of the next five years are as follows:

Year Ending December 31,	Amount (in thousands)
2010	$ —
2011	—
2012	—
2013	357,500
2014	655,650
Thereafter	250,000
Total	$ 1,263,150

The outstanding balance of revolving debt under the revolving credit facility bears interest at LIBOR plus a margin or Alternate Base Rate (equivalent to the U.S prime rate lending rate) plus a margin or a combination of both. The senior notes pay fixed interest rates and the weighted average coupon rate is 8.787 percent. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 5.74 percent during the period from May 26, 2010 to June 30, 2010, 7.98 percent during the period from April 1, 2010 to May 25, 2010, 6.69 percent during the three months ended June 30, 2009, 7.98 percent during the period from January 1, 2010 to May 25, 2010 and 5.94 percent during the six months ended June 30, 2009.

Senior Notes. The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Finance Corp., and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's credit facility and the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of June 30, 2010, the Partnership was in compliance with each of the financial covenants required under the terms of the senior notes.

Finance Corp. has no operations and will not have revenues other than as may be incidental as co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except certain wholly owned subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

Upon a change in control, each holder of the Partnership's senior notes may, at its option, require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages, if any. Subsequent to the ETE Acquisition, no noteholder has exercised this option.

As disclosed in Note 1, the Partnership's long-term debt was adjusted to fair value on May 26, 2010. The fair value of the senior notes was adjusted based on quoted market prices. The re-measurement of the senior notes due 2013 and 2016 resulted in premium of $7,150,000 and $6,563,000, respectively.

The unamortized premium or discount on the Partnership's senior notes as of June 30, 2010 and December 31, 2009 are as follows.

	Successor June 30, 2010	Predecessor December 31, 2009
	(in thousands)	
Senior Notes Due 2013		
Principal amount	$ 357,500	$ 357,500
add:		
Unamortized premium	6,998	—
Carrying value	$ 364,498	$ 357,500
Senior Notes Due 2016		
Principal amount	$ 250,000	$ 250,000
add/ deduct:		
Unamortized premium (discount)	6,492	(12,843)
Carrying value	$ 256,492	$ 237,157

Revolving Credit Facility. On March 4, 2010, RGS executed the Fifth Amended and Restated Credit Agreement (the “new credit agreement”), to be effective as of March 4, 2010. The material differences between the Fourth Amended and Restated Credit Agreement (the “previous credit agreement”) and the new credit agreement include:

- extension of the maturity date to June 15, 2014 from August 15, 2011, subject to the following contingency:
  - if the Partnership’s 8.375 percent senior notes due December 15, 2013 have not been refinanced or paid off by June 15, 2013, then the maturity date of the revolving credit facility will be June 15, 2013;
- an increase in the amount of allowed investments in HPC to $250,000,000 from $135,000,000;
- the addition of an allowance for joint venture investments (other than HPC) of up to $75,000,000, provided that (i) distributed cash and net income from joint ventures under this basket shall be excluded from consolidated net income and (ii) equity interests in joint ventures created under this basket shall be pledged as collateral;
- the modification of financial covenants to give credit for projected EBITDA associated with certain future material HPC projects on a percentage of completion basis, provided that such amount, together with adjustments related to the Haynesville Expansion Project and other material projects, does not exceed 20 percent of consolidated EBITDA (as defined in the new credit agreement) through March 31, 2010, and 15 percent thereafter;
- an increase in the annual general asset sales permitted from $20,000,000 annually to five percent of consolidated net tangible assets (as defined in the new credit agreement) annually.

The Partnership treated the amendment of the credit facility as a modification of an existing revolving credit agreement and, therefore, wrote off debt issuance costs of $1,780,000 to interest expense, net in the period from January 1, 2010 to May 25, 2010. In addition, the Partnership paid and capitalized $15,861,000 of loan fees which will be amortized over the remaining term of the credit facility.

On May 26, 2010, the Partnership entered into the first amendment to its Fifth Amended and Restated Credit Agreement. The amendment, among other things,

- amends the definition of “Consolidated EBITDA” and “Consolidated Net Income” to include MEP;
- amends the definition of “Joint Venture” in the credit agreement to include MEP;
- amends the definition of “Permitted Acquisition” in the agreement to clarify that the initial investment in MEP is a permitted acquisition;
- amends the definition of “Permitted Holder” to include to include ETE as a party that may hold the equity interest in the Managing General Partner without triggering an event of default under the credit agreement;
- allows for the pledge of the equity interest in MEP as a collateral indirectly, through the direct pledge of equity interest in Regency Midcon;
- permits certain investments in MEP by the Partnership and its affiliates;
- requires that the Partnership and its subsidiaries maintain a senior consolidated secured leverage ratio not to exceed 3 to 1.

The new credit agreement and the guarantees are senior to the Partnership's and the guarantors' secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of June 30, 2010, the Partnership was in compliance with each of the financial covenants required under the term of the credit agreement.

7. Commitments and Contingencies

Legal. The Partnership is involved in various claims and lawsuits incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Escrow Payable. At June 30, 2010, $1,011,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area and a subsequent 2008 settlement agreement between the Partnership and El Paso. In the El Paso PSA, El Paso indemnified Regency Gas Services LLC, now known as Regency Gas Services LP, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion. In connection with this matter, $500,000 was released on May 6, 2010.

Environmental. A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made against the Partnership or under the policy.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership's predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. On May 7, 2010, the jury rendered a verdict in favor of Regency. No damages were awarded to the Plaintiffs. Plaintiffs have appealed the verdict. The hearing on appeal will take place sometime in 2011.

Kansas State Severance Tax. In August 2008, a customer began remitting severance tax to the state of Kansas based on the value of condensate purchased from one of the Partnership's Mid-Continent gathering fields and deducting the tax from its payments to the Partnership. The Kansas Department of Revenue advised the customer that it was appropriate to remit such taxes and withhold the taxes from its payments to the Partnership, absent an order or legal opinion from the Kansas Department of Revenue stating otherwise. The Partnership has requested a determination from the Kansas Department of Revenue regarding the matter since severance taxes were already paid on the gas from which the condensate is collected and no additional tax is due. The Kansas Department of Revenue has advised the Partnership that a portion of its condensate sales in Kansas is subject to severance tax; therefore the Partnership will be subject to additional taxes on future condensate sales. The Partnership may also be subject to additional taxes, interest and possible penalties for past condensate sales.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. Regency Field Services LLC ("RFS") currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the "Plants"). The Plants each have groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from El Paso Field Services LP ("El Paso"), Kerr-McGee Corporation ("Kerr-McGee") was performing remediation of the groundwater contamination, because the Plants were once owned by Kerr-McGee and when Kerr-McGee sold the Plants to a predecessor of El Paso in 1988, Kerr-McGee retained liability for any environmental contamination at the Plants. In 2005, Kerr-McGee created and spun off Tronox and Tronox allegedly assumed certain of Kerr-McGee's environmental remediation obligations (including its obligation to perform remediation at the Plants) prior to the acquisition of Kerr-McGee by Anadarko Petroleum Corporation. In January 2009, Tronox filed for Chapter 11 bankruptcy protection. RFS filed a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants. Tronox has thus far
continued its remediation efforts at the Plants. Tronox filed a reorganization plan on July 7, 2010. The plan calls for the creation of a trust to fund environmental clean-up at the various sites where Tronox has an obligation. Tronox must file the Environmental Claims Settlement Agreement, which will set forth the amount of trust funds allocated to each site, 14 days prior to the confirmation hearing, the date for which has not yet been set.

8. Series A Convertible Redeemable Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of March 31, 2010, the Series A Preferred Units were convertible to 4,584,192 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon. The Series A Preferred Units receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010, if outstanding on the record dates of the Partnership's common units distributions. Effective as of March 2, 2010, holders can elect to convert Series A Preferred Units to common units at any time in accordance with the partnership agreement.

Upon a change in control, each unitholder may, at its option, require the Partnership to purchase the Series A Preferred Units for an amount equal to 101 percent of the total of the face value of the Series A Preferred Units plus all accrued but unpaid distribution thereon. Subsequent to the ETE Acquisition, no unitholder has exercised this option.

As disclosed in Note 1, the Partnership's Series A Preferred Units were adjusted to fair value of $70,793,000 on May 26, 2010. The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the six months ended June 30, 2010.

	For the Six Months Ended June 30, 2010,	
	Units	Amount (in thousands)
Beginning balance as of January 1, 2010	4,371,586	$ 51,711
Accretion to redemption value from January 1, 2010 to May 25, 2010	—	55
Balance as of May 25, 2010	4,371,586	51,766
Fair value adjustment	—	19,027
Balance as of May 26, 2010	4,371,586	70,793
Accretion to redemption value from May 26, 2010 to June 30, 2010	—	57
Ending balance as of June 30, 2010	4,371,586	$ 70,850*

* This amount will be accreted to $80,000,000 plus any accrued and unpaid distributions by deducting amounts from partners' capital over the 19.25 remaining years.

9. Related Party Transactions

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $5,660,000, $10,370,000, $31,065,000, $8,591,000 and $16,209,000, were recorded in the Partnership's financial statements during the periods from May 26, 2010 to June 30, 2010, from April 1, 2010 to May 25, 2010, from January 1, 2010 to May 25, 2010 and for the three and six months ended June 30, 2009, respectively, as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS received cash distributions of $13,114,000, $2,603,000, $26,241,000 and $12,181,000 during the period from April 1, 2010 to May 25, 2010, the three months ended June 30, 2009, the period from January 1, 2010 to May 25, 2010 and the six months ended June 30, 2009, respectively.

Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. Under this agreement, the Partnership receives $1,400,000 monthly as a partial reimbursement of its general and administrative costs. The amount is recorded as fee revenue in the Partnership's corporate and other segment. The Partnership also incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. For the periods from May 26, 2010 to June 30, 2010, from April 1, 2010 to May 25, 2010, from January 1, 2010 to May 25, 2010, and the three and six months ended June 30, 2009, the related party general and administrative expenses reimbursed to the Partnership were $1,400,000, $2,800,000, $6,933,000, $1,500,000, and $1,726,000, respectively.

On May 26, 2010, the Partnership received $7,436,000 from ETE, which represents the portion of the estimated amount of the Partnership's common unit distribution to be paid to ETE for the period of time those units were not outstanding (April 1, 2010 to May 25, 2010).

As of June 30, 2010, the Partnership has a related party receivable of $12,288,000 from ETE for an additional capital contribution, which was received on August 6, 2010.

On May 26, 2010, the Partnership entered into a services agreement with ETE and ETE Services Company, LLC ("Services Co."), a subsidiary of ETE. Under the services agreement, Services Co. will perform certain general and administrative services to the Partnership. The Partnership will pay Services Co's direct expenses for these services, plus an annual fee of $10,000,000, and will receive the benefit of any cost savings recognized for these services. The services agreement has a five year term, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default.

As disclosed in Note 3, the Partnership's acquisition of additional 6.99 percent partner's interest in HPC from GE EFS, and the 49.9 percent interest in MEP from ETE are related party transactions.

The Partnership's contract compression segment provides contract compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operation. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Enterprise GP holds a non-controlling equity interest in ETE's general partner and a limited partnership interest in ETE, therefore is considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to the subsidiaries of Enterprise GP and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees with subsidiaries of Enterprise GP and records the cost to cost of sales.

As of June 30, 2010, the Partnership's related party receivables and related party payables included $18,501,000 and $422,000, respectively, from and to subsidiaries of Enterprise GP.

10. Segment Information

In 2009, the Partnership's management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has four reportable segments: (a) gathering and processing, (b) transportation, (c) contract compression and (d) corporate and others. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenues and the associated cost of sales from the gathering and processing segment directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment. The Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

The transportation segment consists of the Partnership's 49.99 percent interest in HPC, which we operate, and the 49.9 percent interest in MEP. Prior periods have been restated to reflect the Partnership's then wholly-owned subsidiary of Regency Intrastate Gas LLC as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with other pipelines, storage facilities or end-use markets. RIG performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The north Louisiana intrastate pipeline operated by this segment serves the Partnership's gathering and processing facilities in the same area and those transactions create a portion of the intersegment revenues shown in the table below.

The contract compression segment provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership's integrated solutions include a comprehensive assessment of a customer's natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and on-going operation, service, and repair of its compression units, which are modified as necessary to adapt to customers' changing operating conditions. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

The corporate and others segment comprises regulated entities and the Partnership's corporate offices. Revenues in this segment include the collection of the partial reimbursement of general and administrative costs from HPC.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the gathering and processing and for the transportation segments, is defined as total revenues, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenues minus direct costs, which primarily consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenues generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Results for each period, together with amounts related to balance sheets for each segment, are shown below.

	Gathering and Processing	Transportation	Contract Compression	Corporate and Others	Eliminations	Total
			(in thousands)			
External Revenues						
Period from May 26, 2010 to June 30, 2010	$ 90,147	$ —	$ 12,053	$ 780	$ —	$ 102,980
Period from April 1, 2010 to May 25, 2010	183,582	—	23,992	3,921	—	211,495
For the three months ended June 30, 2009	209,939	1,531	39,011	3,061	—	253,542
Period from January 1, 2010 to May 25, 2010	460,423	—	58,971	9,853	—	529,247
For the six months ended June 30, 2009	453,093	9,075	77,499	3,853	—	543,520
Intersegment Revenues						
Period from May 26, 2010 to June 30, 2010	—	—	1,999	22	(2,021)	—
Period from April 1, 2010 to May 25, 2010	—	—	3,794	53	(3,847)	—
For the three months ended June 30, 2009	(6,745)	(128)	975	40	5,858	—
Period from January 1, 2010 to May 25, 2010	—	—	9,126	91	(9,217)	—
For the six months ended June 30, 2009	(8,755)	4,936	1,785	144	1,890	—
Cost of Sales						
Period from May 26, 2010 to June 30, 2010	73,311	—	1,564	(772)	(22)	74,081
Period from April 1, 2010 to May 25, 2010	144,768	—	2,460	87	(53)	147,262
For the three months ended June 30, 2009	144,816	1,243	4,186	269	6,833	157,347
Period from January 1, 2010 to May 25, 2010	366,900	—	5,741	(679)	(91)	371,871
For the six months ended June 30, 2009	327,284	2,297	6,504	116	3,674	339,875
Segment Margin						
Period from May 26, 2010 to June 30, 2010	16,836	—	12,488	1,574	(1,999)	28,899
Period from April 1, 2010 to May 25, 2010	38,814	—	25,326	3,887	(3,794)	64,233
For the three months ended June 30, 2009	58,378	160	35,800	2,832	(975)	96,195
Period from January 1, 2010 to May 25, 2010	93,523	—	62,356	10,623	(9,126)	157,376
For the six months ended June 30, 2009	117,054	11,714	72,780	3,881	(1,784)	203,645
Operation and Maintenance						
Period from May 26, 2010 to June 30, 2010	8,814	—	4,924	203	(1,999)	11,942
Period from April 1, 2010 to May 25, 2010	15,400	—	9,698	126	(3,794)	21,430
For the three months ended June 30, 2009	22,044	(174)	11,487	(181)	(1,202)	31,974
Period from January 1, 2010 to May 25, 2010	39,161	—	23,476	327	(9,123)	53,841
For the six months ended June 30, 2009	44,349	2,112	24,028	132	(2,605)	68,016
Depreciation and Amortization						
Period from May 26, 2010 to June 30, 2010	7,413	—	3,323	259		10,995
Period from April 1, 2010 to May 25, 2010	11,576	—	6,353	680	—	18,609
For the three months ended June 30, 2009	16,413	—	8,955	868	—	26,236
Period from January 1, 2010 to May 25, 2010	28,864	—	15,560	1,660	—	46,084
For the six months ended June 30, 2009	33,134	2,448	16,982	1,561	—	54,125
Income from Unconsolidated Subsidiaries						
Period from May 26, 2010 to June 30, 2010	—	8,121	—	—		8,121
Period from April 1, 2010 to May 25, 2010	—	7,959	—	—	—	7,959
For the three months ended June 30, 2009	—	1,587	—	—	—	1,587
Period from January 1, 2010 to May 25, 2010	—	15,872	—	—		15,872
For the six months ended June 30, 2009	—	1,923	—	—	—	1,923
Assets						
June 30, 2010	1,751,253	1,369,921	1,362,549	111,569	—	4,595,292
December 31, 2009	1,046,619	453,120	926,213	107,462	—	2,533,414
Investment in Unconsolidated Subsidiaries						
June 30, 2010	—	1,369,921	—	—	—	1,369,921
December 31, 2009	—	453,120	—	—	—	453,120
Goodwill						
June 30, 2010	286,634	—	447,040	—	—	733,674
December 31, 2009	63,232	—	164,882	—	—	228,114
Expenditures for Long-Lived Assets						
Period from May 26, 2010 to June 30, 2010	15,300	—	5,208	367	—	20,875
Period from January 1, 2010 to May 25, 2010	43,666	—	18,418	1,703		63,787
For the six months ended June 30, 2009	44,639	22,367	50,959	1,220	—	119,185

The table below provides a reconciliation of total segment margin to net income (loss) from continuing operations.

	Successor	Predecessor			
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to Disposition (May 25, 2010)	Three Months Ended June 30, 2009	Period from January 1, 2010 to Disposition (May 25, 2010)	Six Months Ended June 30, 2009
	(in thousands)	(in thousands)			
Net (loss) income attributable to Regency Energy Partners LP	$ (4,924)	$ (4,740)	$ 5,890	$ (5,352)	$ 154,279
Add (deduct):					
Operation and maintenance	11,942	21,430	31,974	53,841	68,016
General and administrative	7,104	21,809	14,127	37,212	29,205
Loss (gain) on asset sales, net	10	19	651	303	(133,280)
Depreciation and amortization	10,995	18,609	26,236	46,084	54,125
Income from unconsolidated subsidiaries	(8,121)	(7,959)	(1,587)	(15,872)	(1,923)
Interest expense, net	8,109	14,114	19,568	36,459	33,795
Other income and deductions, net	3,510	624	(214)	3,891	(256)
Income tax expense (benefit)	245	83	(515)	404	(416)
Net income attributable to the noncontrolling interest	29	244	65	406	100
Total segment margin	$ 28,899	$ 64,233	$ 96,195	$ 157,376	$ 203,645

11. Equity-Based Compensation

The Partnership's LTIP for its employees, directors and consultants authorizes grants up to 2,865,584 common units. Because control changed from GE EFS to ETE, all then outstanding LTIP, exclusive of the May 7, 2010 phantom unit grant described below, vested during the predecessor period and the Partnership recorded a one-time general and administrative charge of $9,893,000 as a result of the vesting of these units on May 25, 2010. LTIP compensation expense of $137,000, $10,431,000, $12,070,000, $1,561,000 and $2,750,000 is recorded in general and administrative expense in the statement of operations for the periods from May 26, 2010 to June 30, 2010, April 1, 2010 to May 25, 2010 and January 1, 2010 to May 25, 2010, and for the three and six months ended June 30, 2009, respectively.

Common Unit Option and Restricted (Non-Vested) Units.

The common unit options activity for the six months ended June 30, 2010 is as follows.

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period	306,651	$ 21.50		
Granted	—	—		
Exercised	(13,500)	20.00		
Forfeited or expired	(3,001)	23.73		
Outstanding at end of period	290,150	21.57	5.8	833
Exercisable at the end of the period	290,150			833

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented, unit options with an exercise price greater than the end of the period closing market price are excluded.

During the six months ended June 30, 2010, the Partnership received $270,000 in proceeds from the exercise of unit options.

The restricted (non-vested) common unit activity for the six months ended June 30, 2010 is as follows.

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	464,009	$ 28.36
Granted	—	—
Vested	(444,759)	28.19
Forfeited or expired	(19,250)	32.35
Outstanding at the end of period	—	—

Phantom Units. The Partnership's phantom units are in substance two grants composed of (1) service condition grants with graded vesting over three years; and (2) market condition grants with cliff vesting based upon the Partnership's relative ranking in total unitholder return among 20 peer companies, as disclosed in Item 11 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009. As control changed from GE EFS to ETE, all outstanding phantom units, exclusive of the May 7, 2010 grant described below, vested. The service condition grants vested at a rate of 100 percent and the market condition grants vested at a rate of 150 percent pursuant to the terms of the award.

The Partnership awarded 247,500 phantom units to senior management and certain key employees on May 7, 2010. These phantom units include a provision that will accelerate vesting (1) upon a change in control and (2) within 12 months of a change in control, if termination without “Cause” (as defined) or resignation for “Good Reason” (as defined) occurs, the phantom units will vest. The Partnership expects to recognize $3,187,000 of compensation expense related to non-vested phantom units over a period of 2.8 years.

The following table presents phantom unit activity for the six months ended June 30, 2010.

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	301,700	$ 8.63
Service condition grants	108,500	20.76
Market condition grants	148,500	11.89
Vested service condition	(138,313)	13.97
Vested market condition	(168,420)*	4.65
Forfeited service condition	(6,467)	19.30
Forfeited market condition	(10,500)	10.20
Total outstanding at end of period	235,000	16.31

* Upon the change in control, these awards converted into 252,630 common units.

12. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1 - unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2 - inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3 - inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

Derivatives. The Partnership’s financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument’s term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy. The change in fair value of the derivatives related to Series A Preferred Units is recorded in other income and deductions, net within the statement of operations.

The following table presents the Partnership’s derivative assets and liabilities measured at fair value on a recurring basis.

	Fair Value Measurement at June 30, 2010				Fair Value Measurement at December 31, 2009			
	Fair Value Total	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value Total	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
	(in thousands)							
Assets								
Commodity Derivatives:								
Natural Gas	3,125	—	3,125	—	602	—	602	—
Natural Gas Liquids	12,222	—	12,222	—	15,484	—	15,484	—
Condensate	5,727	—	5,727	—	9,108	—	9,108	—
Total Assets	21,074	—	21,074	—	25,194	—	25,194	—
Liabilities								
Interest rate swaps	1,877	—	1,877	—	1,064	—	1,064	—
Commodity Derivatives:		—		—		—		—
Natural Gas	15	—	15	—	51	—	51	—
Natural Gas Liquids	2,025	—	2,025	—	15,034	—	15,034	—
Condensate	29	—	29	—	416	—	416	—
Series A Preferred Units	52,239	—	—	52,239	44,594	—	—	44,594
Total Liabilities	56,185	—	3,946	52,239	61,159	—	16,565	44,594

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the six months ended June 30, 2010.

	Derivatives related to Series A Preferred Units (in thousands)
Beginning Balance- December 31, 2009	$ 44,594
Net unrealized losses included in other income and deductions, net	4,039
Ending Balance- May 25, 2010	48,633
Net unrealized losses included in other income and deductions, net	3,606
Ending Balance- June 30, 2010	$ 52,239

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. Long-term debt, other than the senior notes, is comprised of borrowings which incur interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair values of the senior notes due 2013 and 2016, based on third party market value quotations as of June 30, 2010, were $369,119,000 and $265,000,000, respectively.

13. Subsequent Events

On July 27, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit and Series A Preferred Unit, including units equivalent to the General Partner’s two percent interest in the Partnership, and a distribution with respect to incentive distribution rights of approximately $915,000, payable on August 13, 2010, to unitholders of record at the close of business on August 6, 2010.

On July 15, 2010, the Partnership sold its gathering and processing assets located in east Texas to an affiliate of Tristream Energy LLC for approximately $70,000,000. The Partnership plans to use the proceeds from the sale of the assets to fund future capital expenditures.

On August 6, 2010, the Partnership agreed to acquire Zephyr Gas Services, LLC, a field services company for approximately $185,000,000.

Regency GP LP

Consolidated Financial Statements
December 31, 2009 and 2008
With Independent Auditors' Report Thereon

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Partners
Regency GP LP:

We have audited the accompanying consolidated balance sheets of Regency GP LP and subsidiaries as of December 31, 2009 and 2008 and the related consolidated statements of operations, comprehensive income (loss), cash flows, and partners' capital and noncontrolling interest for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Regency GP LP and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Dallas, Texas
September 13, 2010

Regency GP LP
Consolidated Balance Sheets
(in thousands)

	December 31, 2009	December 31, 2008
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 9,828	$ 600
Restricted cash	1,511	10,031
Trade accounts receivable, net of allowance of $1,130 and $941	30,433	40,875
Accrued revenues	95,240	96,712
Related party receivables	6,222	855
Derivative assets	24,987	73,993
Other current assets	10,556	13,338
Total current assets	178,777	236,404
Property, Plant and Equipment:		
Gathering and transmission systems	465,959	652,267
Compression equipment	823,060	799,527
Gas plants and buildings	159,596	156,246
Other property, plant and equipment	162,433	167,256
Construction-in-progress	95,547	154,852
Total property, plant and equipment	1,706,595	1,930,148
Less accumulated depreciation	(250,160)	(226,594)
Property, plant and equipment, net	1,456,435	1,703,554
Other Assets:		
Investment in unconsolidated subsidiary	453,120	—
Long-term derivative assets	207	36,798
Other, net of accumulated amortization of debt issuance costs of $10,743 and $5,246	19,468	13,880
Total other assets	472,795	50,678
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $33,929 and $22,517	197,294	205,646
Goodwill	228,114	262,358
Total intangible assets and goodwill	425,408	468,004
TOTAL ASSETS	$2,533,415	$2,458,640
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 44,912	$ 65,483
Accrued cost of gas and liquids	76,657	76,599
Related party payables	2,312	—
Deferred revenue, including related party amounts of $338 and $0	11,292	11,572
Derivative liabilities	12,256	42,691
Escrow payable	1,511	10,031
Other current liabilities	12,368	10,574
Total current liabilities	161,308	216,950
Long-term derivative liabilities	48,903	560
Other long-term liabilities	14,183	15,487
Long-term debt, net	1,014,299	1,126,229
Commitments and contingencies		
Series A convertible redeemable subsidiary preferred units, redemption amount $83,891	51,711	—
Partners' Capital and Noncontrolling Interest:		
Partners' interest	19,250	29,284
Accumulated other comprehensive (loss) income	(1,994)	67,440
Noncontrolling interest	1,225,755	1,002,690
Total partners' capital and noncontrolling interest	1,243,011	1,099,414
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$2,533,415	$2,458,640

See accompanying notes to consolidated financial statements

Regency GP LP
Consolidated Statements of Operations
(in thousands)

	Year Ended December 31, 2009	2008	2007
REVENUES			
Gas sales	$ 481,400	$1,126,760	$ 744,681
NGL sales	262,652	409,476	347,737
Gathering, transportation and other fees, including related party amounts of $11,162, $3,763 and $1,350	273,770	286,507	100,644
Net realized and unrealized gain (loss) from derivatives	41,577	(21,233)	(34,266)
Other	30,098	62,294	31,442
Total revenues	1,089,497	1,863,804	1,190,238
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $10,913, $1,878 and $14,165	699,563	1,408,333	976,145
Operation and maintenance	130,826	131,629	58,000
General and administrative	57,863	51,323	39,713
Loss (gain) on asset sales, net	(133,284)	472	1,522
Management services termination fee	—	3,888	—
Transaction expenses	—	1,620	420
Depreciation and amortization	109,893	102,566	55,074
Total operating costs and expenses	864,861	1,699,831	1,130,874
OPERATING INCOME	224,636	163,973	59,364
Income from unconsolidated subsidiary	7,886	—	—
Interest expense, net	(77,996)	(63,243)	(52,016)
Loss on debt refinancing	—	—	(21,200)
Other income and deductions, net	(15,132)	332	1,252
INCOME (LOSS) BEFORE INCOME TAXES	139,394	101,062	(12,600)
Income tax (benefit) expense	(1,095)	(266)	931
NET INCOME (LOSS)	$ 140,489	$ 101,328	$ (13,531)
Net (income) loss attributable to noncontrolling interest	(135,237)	(91,361)	13,138
NET INCOME (LOSS) ATTRIBUTABLE TO REGENCY GP LP	$ 5,252	$ 9,967	$ (393)

See accompanying notes to consolidated financial statements

Regency GP LP
Consolidated Statements of Comprehensive Income (Loss)
(in thousands)

	Year Ended December 31,		
	2009	2008	2007
Net income (loss)	$140,489	$101,328	$(13,531)
Net hedging amounts reclassified to earnings	(47,394)	35,512	19,362
Net change in fair value of cash flow hedges	(22,040)	70,253	(58,706)
Comprehensive income (loss)	$ 71,055	$207,093	$(52,875)
Comprehensive income (loss) attributable to noncontrolling interest	67,192	195,011	(51,695)
Comprehensive income (loss) attributable to Regency GP LP	$ 3,863	$ 12,082	$ (1,180)

See accompanying notes to consolidated financial statements

Regency GP LP
Consolidated Statements of Cash Flows
(in thousands)

	Year Ended December 31,		
	2009	2008	2007
OPERATING ACTIVITIES			
Net income (loss)	$ 140,489	$ 101,328	$ (13,531)
Adjustments to reconcile net income (loss) to net cash flows provided by operating activities:			
Depreciation and amortization, including debt issuance cost amortization	116,307	105,324	57,069
Write-off of debt issuance costs	—	—	5,078
Non-cash income from unconsolidated subsidiary	—	—	(43)
Derivative valuation changes	5,163	(14,700)	14,667
Loss (gain) on asset sales, net	(133,284)	472	1,522
Subsidiary unit based compensation expenses	6,008	4,306	15,534
Gain on insurance settlements	—	(3,282)	—
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues, and related party receivables	10,727	18,648	(28,789)
Other current assets	10,471	(6,615)	(1,394)
Trade accounts payable, accrued cost of gas and liquids, and related party payables	(3,762)	(40,772)	30,089
Other current liabilities	(6,726)	12,749	(149)
Amount of swap termination proceeds reclassified into earnings	—	—	(1,078)
Other assets and liabilities	(1,433)	3,840	554
Net cash flows provided by operating activities	143,960	181,298	79,529
INVESTING ACTIVITIES			
Capital expenditures	(193,083)	(375,083)	(129,784)
Acquisitions	(52,803)	(577,668)	(34,855)
Return of investment in unconsolidated subsidiary	1,039	—	—
Acquisition of investment in unconsolidated subsidiary, net of $100 cash	—	—	(5,000)
Net proceeds from asset sales	88,682	840	11,706
Proceeds from insurance settlement	—	3,282	—
Net cash flows used in investing activities	(156,165)	(948,629)	(157,933)
FINANCING ACTIVITIES			
Net (repayments) borrowings under revolving credit facilities	(349,087)	644,729	9,300
Proceeds from issuance (repayments) of senior notes, net of discount	236,240	—	(192,500)
Debt issuance costs	(12,224)	(2,940)	(2,427)
Partner contributions	6,344	11,746	7,735
Distribution to partners	(5,360)	(3,716)	(1,599)
Distribution to noncontrolling interest	(141,225)	(116,875)	(78,334)
Acquisition of assets between entities under common control in excess of historical cost	(10,197)	—	—
Proceeds from subsidiary option exercises	—	2,700	—
Proceeds from subsidiary equity issuances, net of issuance costs	220,318	199,315	353,546
Proceeds from subsidiary issuance of Series A Preferred Units, net of issuance costs	76,624	—	—
FrontStreet distributions	—	—	(9,695)
FrontStreet contributions	—	—	13,417
Net cash flows provided by financing activities	21,433	734,959	99,443
Net increase (decrease) in cash and cash equivalents	9,228	(32,372)	21,039
Cash and cash equivalents at beginning of period	600	32,972	9,140
Cash acquired from FrontStreet	—	—	2,793
Cash and cash equivalents at end of period	$ 9,828	$ 600	$ 32,972
Supplemental cash flow information:			
Interest paid, net of amounts capitalized	$ 69,401	$ 59,969	$ 67,844
Income taxes paid, net of refunds	6	605	—
Non-cash capital expenditures in accounts payable	9,688	25,845	7,761
Non-cash capital expenditure for consolidation of investment in previously unconsolidated subsidiary	—	—	5,650
Non-cash capital expenditure upon entering into a capital lease obligation	—	—	3,000
Issuance of common units for an acquisition	—	219,560	19,724
Release of escrow payable from restricted cash	8,501	4,570	—
Contribution of fixed assets, goodwill and working capital to HPC	263,921	—	—
Non-cash proceeds from contribution of RIGS to HPC	403,568	—	—
Distributions accrued but not paid to Series A Preferred Units	3,891		

See accompanying notes to consolidated financial statements

Regency GP LP
Consolidated Statements of Partners' Capital and Noncontrolling Interest
(in thousands except unit data)

	Partners' Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance—December 31, 2006	$ 5,544	$ 1,019	$ 206,095	$ 212,658
Subsidiary issuance of common units for acquisition	—	—	19,724	19,724
Subsidiary issuance of common units, net of issuance cost	—	—	353,446	353,446
Exercise of subsidiary common unit options	—	—	100	100
Subsidiary unit based compensation expenses	—	—	15,534	15,534
Distributions to partners	(1,599)		—	(1,599)
Subsidiary distributions	—	—	(78,334)	(78,334)
Partner contributions	7,735	—	—	7,735
Acquisition of FrontStreet	—	—	83,448	83,448
FrontStreet contributions	—	—	13,417	13,417
FrontStreet distributions	—	—	(9,695)	(9,695)
Contributions from noncontrolling interest	—	—	4,588	4,588
Net loss	(393)	—	(13,138)	(13,531)
Other	—	—	40	40
Net hedging activity reclassified to earnings	—	19,362	—	19,362
Net change in fair value of cash flow hedges	—	(58,706)	—	(58,706)
Balance—December 31, 2007	11,287	(38,325)	595,225	568,187
Subsidiary issuance of Class D common units	—	—	219,560	219,560
Subsidiary option exercises	—	—	2,700	2,700
Subsidiary issuance of common units, net of issuance cost	—	—	199,315	199,315
Working capital adjustment on FrontStreet	—	—	(858)	(858)
Acquisition on noncontrolling interest	—	—	(4,893)	(4,893)
Subsidiary unit based compensation expenses	—	—	4,306	4,306
Distributions to partners	(3,716)		—	(3,716)
Subsidiary distributions	—	—	(116,875)	(116,875)
Partner contributions	11,746	—	—	11,746
Net income	9,967	—	91,361	101,328
Contributions from noncontrolling interest	—	—	12,849	12,849
Net hedging amounts reclassified to earnings	—	35,512	—	35,512
Net change in fair value of cash flow hedges	—	70,253	—	70,253
Balance—December 31, 2008	29,284	67,440	1,002,690	1,099,414
Revision of partner interest	(6,073)	—	6,073	—
Subsidiary issuance of common units, net of issuance cost	—	—	220,318	220,318
Subsidiary unit based compensation expenses	—	—	6,008	6,008
Accrued distributions to subsidiary phantom units	—	—	(249)	(249)
Acquisition of assets between entities under common control in excess of historical cost	(10,197)	—	—	(10,197)
Distributions to partners	(5,360)		—	(5,360)
Subsidiary distributions	—	—	(141,225)	(141,225)
Partner contributions	6,344	—	—	6,344
Net income	5,252	—	135,237	140,489
Contributions from noncontrolling interest	—	—	898	898
Accrued distributions to Series A Preferred Units	—	—	(3,891)	(3,891)
Accretion of Series A Preferred Units	—	—	(104)	(104)
Net cash flow hedge amounts reclassified to earnings	—	(47,394)	—	(47,394)
Net change in fair value of cash flow hedges	—	(22,040)	—	(22,040)
Balance—December 31, 2009	$ 19,250	$ (1,994)	$ 1,225,755	$1,243,011

See accompanying notes to consolidated financial statements

Regency GP LP
Notes to Consolidated Financial Statements
For the Year Ended December 31, 2009

1. Organization and Basis of Presentation

Organization of Regency GP LP. Regency GP LP (the "General Partner") is the general partner of Regency Energy Partners LP. The General Partner owns a 2 percent general partner interest and incentive distribution rights in Regency Energy Partners LP. The General Partner's general partner is Regency GP LLC.

Organization of Regency Energy Partners LP. Regency Energy Partners LP and its subsidiaries (the "Partnership") are engaged in the business of gathering, processing and transporting natural gas and natural gas liquids ("NGLs") as well as providing contract compression services.

On June 18, 2007, General Electric Energy Financial Services ("GE EFS"), which is comprised of indirect subsidiaries of General Electric Capital Corporation ("GECC"), an indirect wholly owned subsidiary of General Electric Company, acquired 91.3 percent of both the member interest in the General Partner and the outstanding limited partner interests in the General Partner from an affiliate of HM Capital Partners LLC and acquired 17,763,809 of the outstanding subordinated units, exclusive of 1,222,717 subordinated units which were owned directly or indirectly by certain members of the Partnership's then existing management. The Partnership was not required to record any adjustments to reflect the acquisition of the HM Capital Partners LLC's interest in the Partnership or the related transactions (together, referred to as "GE EFS Acquisition").

In January 2008, the Partnership acquired all of the outstanding equity and noncontrolling interest (the "FrontStreet Acquisition") of FrontStreet Hugoton LLC ("FrontStreet") from ASC Hugoton LLC ("ASC"), an affiliate of GECC, and FrontStreet EnergyOne LLC ("EnergyOne"). Because the acquisition of ASC's 95 percent interest was a transaction between commonly controlled entities, the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Information included in these financial statements is presented as if the FrontStreet Acquisition had been combined throughout the periods presented in which common control existed, June 18, 2007 forward. Conversely, the acquisition of EnergyOne's noncontrolling interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting.

In March 2009, the Partnership contributed Regency Intrastate Gas LLC ("RIG") to a RIGS Haynesville Partnership Co. ("HPC") in exchange for a noncontrolling interest in HPC. Accordingly, the Partnership no longer consolidates RIG in its financial statements, and accounts for its investment in HPC under the equity method. Transactions between the Partnership and HPC involve the transportation of natural gas, contract compression services, and the provision of administrative support. Because these transactions are immediately realized, the Partnership does not eliminate these transactions with its equity method investee.

Basis of presentation. The consolidated financial statements of the General Partner and the Partnership have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the accounts of all controlled subsidiaries after the elimination of all intercompany accounts and transactions. The General Partner has no independent operations and no material assets outside those of the Partnership. The number of reconciling items between the consolidated financial statements and that of the Partnership are few. The most significant difference is that relating to noncontrolling interest ownership in the General Partner's net assets by certain limited partners of the Partnership, and the elimination of General Partner's investment in the Partnership.

2. Summary of Significant Accounting Policies

Use of Estimates. These consolidated financial statements have been prepared in conformity with GAAP, which includes the use of estimates and assumptions by management that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities that exist at the date of the financial statements. Although these estimates are based on management's available knowledge of current and expected future events, actual results could be different from those estimates.

Consolidation. The General Partner consolidates the financial statements of the Partnership with that of the General Partner. This accounting consolidation is required because the General Partner owns 100 percent of the general partner interest in the Partnership, which gives the General Partner the ability to exercise control over the Partnership.

Cash and Cash Equivalents. Cash and cash equivalents include temporary cash investments with original maturities of three months or less.

Restricted Cash. Restricted cash of $1,511,000 is held in escrow for purchase indemnifications related to the El Paso acquisition and for environmental remediation projects. A third-party agent invests funds held in escrow in US Treasury securities. Interest earned on the investment is credited to the escrow account.

Equity Method Investments. The equity method of accounting is used to account for the Partnership's interest in investments of greater than 20 percent voting interest or exerts significant influence over an investee and where the Partnership lacks control over the investee.

Property, Plant and Equipment. Property, plant and equipment is recorded at historical cost of construction or, upon acquisition, the fair value of the assets acquired. Sales or retirements of assets, along with the related accumulated depreciation, are included in operating income unless the disposition is treated as discontinued operations. Natural gas and NGLs used to maintain pipeline minimum pressures is capitalized and classified as property, plant and equipment. Financing costs associated with the construction of larger assets requiring ongoing efforts over a period of time are capitalized. For the years ended December 31, 2009, 2008, and 2007, the Partnership capitalized interest of $1,722,000, $2,409,000 and $1,754,000, respectively. The costs of maintenance and repairs, which are not significant improvements, are expensed when incurred. Expenditures to extend the useful lives of the assets are capitalized.

The Partnership accounts for its asset retirement obligations by recognizing on its balance sheet the net present value of any legally-binding obligation to remove or remediate the physical assets that it retires from service, as well as any similar obligations for which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Partnership. While the Partnership is obligated under contractual agreements to remove certain facilities upon their retirement, management is unable to reasonably determine the fair value of such asset retirement obligations because the settlement dates, or ranges thereof, were indeterminable and could range up to 95 years, and the undiscounted amounts are immaterial. An asset retirement obligation will be recorded in the periods wherein management can reasonably determine the settlement dates.

Depreciation expense related to property, plant and equipment was $97,426,000, $88,828,000, and $50,719,000 for the years ended December 31, 2009, 2008, and 2007, respectively. Depreciation of plant and equipment is recorded on a straight-line basis over the following estimated useful lives.

Functional Class of Property	Useful Lives (Years)
Gathering and transmission systems	5 - 20
Compression equipment	10 - 30
Gas plants and buildings	15 - 35
Other property, plant and equipment	3 - 10

Intangible Assets. Intangible assets consisting of (i) permits and licenses, (ii) customer contracts, (iii) trade name, and (iv) customer relations are amortized on a straight line basis over their estimated useful lives, which is the period over which the assets are expected to contribute directly or indirectly to the Partnership's future cash flows. The estimated useful lives range from three to 30 years.

The Partnership assesses long-lived assets, including property, plant and equipment and intangible assets, for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability is assessed by comparing the carrying amount of an asset to undiscounted future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured as the amount by which the carrying amounts exceed the fair value of the assets. The Partnership did not record any impairment in 2009, 2008 or 2007.

Goodwill. Goodwill represents the excess of the purchase price over the fair value of identifiable net assets acquired in a business combination. Goodwill is not amortized, but is tested for impairment annually based on the carrying values as of December 31, or more frequently if impairment indicators arise that suggest the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time it is determined that an impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, the Partnership makes estimates and judgments about future cash flows, as well as revenues, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent forecast. No impairment was indicated for the years ended December 31, 2009, 2008, or 2007.

Other Assets, net. Other assets, net primarily consists of debt issuance costs, which are capitalized and amortized to interest expense, net over the life of the related debt. Taxes incurred on behalf of, and passed through to, the Partnership's compression customers are accounted for on a net basis.

Gas Imbalances. Quantities of natural gas or NGLs over-delivered or under-delivered related to imbalance agreements are recorded monthly as other current assets or other current liabilities using then current market prices or the weighted average prices of natural gas or NGLs at the plant or system pursuant to imbalance agreements for which settlement prices are not contractually established. Within certain volumetric limits determined at the sole discretion of the creditor, these imbalances are generally settled by deliveries of natural gas. Imbalance receivables and payables as of December 31, 2009 and 2008 were immaterial.

Revenue Recognition. The Partnership earns revenue from (i) domestic sales of natural gas, NGLs and condensate, (ii) natural gas gathering, processing and transportation, and (iii) contract compression services. Revenue associated with sales of natural gas, NGLs and condensate are recognized when title passes to the customer, which is when the risk of ownership passes to the purchaser and physical delivery occurs. Revenue associated with transportation and processing fees are recognized when the service is provided. For contract compression services, revenue is recognized when the service is performed. For gathering and processing services, the Partnership receives either fees or commodities from natural gas producers depending on the type of contract. Commodities received are in turn sold and recognized as revenue in accordance with the criteria outlined above. Under the percentage-of-proceeds contract type, the Partnership is paid for its services by keeping a percentage of the NGLs produced and a percentage of the residue gas resulting from processing the natural gas. Under the percentage-of-index contract type, the Partnership earns revenue by purchasing wellhead natural gas at a percentage of the index price and selling processed natural gas at a price approximating the index price and NGLs to third parties. The Partnership generally reports revenue gross in the consolidated statements of operations when it acts as the principal, takes title to the product, and incurs the risks and rewards of ownership. Revenue for fee-based arrangements is presented net, because the Partnership takes the role of an agent for the producers. Allowance for doubtful accounts is determined based on historical write-off experience and specific identification.

Derivative Instruments. The Partnership's net income and cash flows are subject to volatility stemming from changes in market prices such as natural gas prices, NGLs prices, processing margins and interest rates. The Partnership uses ethane, propane, butane, natural gasoline, and condensate swaps to create offsetting positions to specific commodity price exposures. Derivative financial instruments are recorded on the balance sheet at their fair value on a net basis by settlement date. The Partnership employs derivative financial instruments in connection with an underlying asset, liability and/or anticipated transaction and not for speculative purposes. Derivative financial instruments qualifying for hedge accounting treatment have been designated by the Partnership as cash flow hedges. The Partnership enters into cash flow hedges to hedge the variability in cash flows related to a forecasted transaction. At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives are highly effective in offsetting changes in cash flows of the hedged item. Furthermore, the Partnership regularly assesses the creditworthiness of counterparties to manage the risk of default. If the Partnership determines that a derivative is no longer highly effective as a hedge, it discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are effective, are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. In the statement of cash flows, the effects of settlements of derivative instruments are classified consistent with the related hedged transactions. For the Partnership's derivative financial instruments that were not designated for hedge accounting, the change in market value is recorded as a component of net unrealized and realized gain (loss) from derivatives in the consolidated statements of operations.

Benefits. The Partnership provides medical, dental, and other healthcare benefits to employees. The Partnership provides a matching contribution for employee contributions to their 401(k) accounts, which vests ratably over 3 years. The amount of matching contributions for the years ended December 31, 2009, 2008, and 2007 were $1,440,000, $395,000, and $469,000, respectively, and were recorded in general and administrative expenses. The Partnership has no pension obligations or other post employment benefits.

Income Taxes. The General Partner and the Partnership are generally not subject to income taxes, except as discussed below, because their income are taxed directly to their partners. The Partnership is subject to the gross margin tax enacted by the state of Texas. The Partnership has wholly-owned subsidiaries that are subject to income tax and provides for deferred income taxes using the asset and liability method for these entities. Accordingly, deferred taxes are recorded for differences between the tax and book basis that will reverse in future periods. The Partnership's deferred tax liability of $6,996,000 and $8,156,000 as of December 31, 2009 and 2008 relates to the difference between the book and tax basis of property, plant and equipment and intangible assets and is included in other long-term liabilities in the accompanying consolidated balance sheet. The Partnership follows the guidance for uncertainties in income taxes where a liability for an unrecognized tax benefit is recorded for a tax position that does not meet the "more likely than not" criteria. The Partnership has not recorded any uncertain tax positions meeting the more likely than not criteria as of December 31, 2009 and 2008. The Partnership's entities that are required to pay federal income tax recognized current federal income tax benefit (expense) of $420,000, ($62,000), and ($1,171,000), and deferred income tax benefit of $1,160,000, $486,000, and $240,000 using a 35 percent effective rate during the years ended December 31, 2009, 2008 and 2007.

As of December 31, 2009, the IRS is conducting an audit to the tax returns of Pueblo Holdings Inc., a wholly-owned subsidiary of the Partnership, for the tax years ended December 31, 2007 and December 31, 2008. In addition, on January 27, 2010, the IRS mailed two "Notice of Beginning of Administrative Proceeding" to the Partnership stating that the IRS is commencing audits of the Partnership's 2007 and 2008 partnership tax returns.

Equity-Based Compensation. The Partnership accounts for equity-based compensation by recognizing the grant-date fair value of awards into expense as they are earned, using an estimated forfeiture rate. The forfeiture rate assumption is reviewed annually to determine whether any adjustments to expense are required.

Revision to Partners' Capital Accounts. In 2009, the Partnership revised the allocation of net income between the General Partner and noncontrolling interest related to 2008 to reflect the income allocation provisions of the Partnership agreement. The effect of this revision is not material to the prior financial statements.

Noncontrolling Interest. Noncontrolling interest represents noncontrolling ownership interest in the net assets of the Partnership. The noncontrolling interest attributable to the limited partners of the Partnership consists of common units of the Partnership and the noncontrolling interest in a subsidiary. The non-affiliated interest in noncontrolling interest as of December 31, 2009 and 2008 was $903,243,000 and $743,872,000, respectively.

Recently Issued Accounting Standards. In June 2009, the FASB issued guidance that significantly changed the consolidation model for variable interest entities. The guidance is effective for annual reporting periods that begin after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership has evaluated this guidance and determined that it will have no impact on its financial position, results of operations or cash flows as a result of adopting this guidance on January 1, 2010.

In January 2010, the FASB issued guidance requiring improved disclosure of transfers in and out of Levels 1 and 2 for an entity's fair value measurements, such requirement becoming effective for interim and annual periods beginning after December 15, 2009. Further, additional disclosure of activities such as purchases, sales, issuances and settlements of items relying on Level 3 inputs will be required, such requirements becoming effective for interim and annual periods beginning after December 15, 2010. The Partnership has evaluated this guidance and determined that it will have no impact on its financial position, results of operations or cash flows upon adopting this guidance.

In February 2010, the FASB clarified the type of embedded credit derivative that is exempt from embedded derivative bifurcation requirements. The Partnership evaluated determined that this guidance had no impact on its financial position, results of operations or cash flows.

3. Partners' Capital and Distributions

General Partner Interest and Incentive Distribution Rights. Partners' capital of the General Partner is represented by 1,901,803 equivalent units as of December 31, 2009. The General Partner has the right, but not the obligation, to contribute a proportionate amount of capital to the Partnership to maintain its current general partner interest. The General Partner's initial 2 percent interest in these distributions will be reduced if the Partnership issues additional units in the future and the General Partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2 percent General Partner interest.

The incentive distribution rights held by the General Partner entitles it to receive an increasing share of Available Cash (defined below) when pre-defined distribution targets are achieved. The General Partner's incentive distribution rights are not reduced if the Partnership issues additional units in the future and the general partner does not contribute a proportionate amount of capital to the Partnership to maintain its 2 percent general partner interest.

Noncontrolling Interest. Noncontrolling interest represents noncontrolling interest in the net assets of the Partnership. The noncontrolling interest attributable to the limited partners of the Partnership consists of common units of the Partnership and a gas gathering joint venture in south Texas 40 percent owned by a third party.

Subsidiary Common Unit Offerings. In August 2008, the Partnership sold 9,020,909 common units and received $204,133,000 in proceeds, inclusive of the General Partner's proportionate capital contribution. In December 2009, the Partnership sold 12,075,000 common units and received $225,030,000 in proceeds, inclusive of the General Partner's proportionate capital contribution.

Subsidiary Subordinated Units. The subordinated units converted into common units on a one-for-one basis on February 17, 2009.

Subsidiary Class E Common Units. On January 7, 2008, the Partnership issued 4,701,034 of Class E common units to ASC as consideration for the FrontStreet Acquisition. The Class E common units had the same terms and conditions as the Partnership's common units, except that the Class E common units were not entitled to participate in earnings or distributions by the Partnership. The Class E common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class E common units converted into common units on a one-for-one basis on May 5, 2008.

Subsidiary Class D Common Units. On January 15, 2008, the Partnership issued 7,276,506 of Class D common units to owners of CDM Resource Management LLC ("CDM") as partial consideration for the CDM acquisition. The Class D common units had the same terms and conditions as the Partnership's common units, except that the Class D common units were not entitled to participate in earnings or distributions by the Partnership. The Class D common units were issued in a private placement conducted in accordance with the exemption from the registration requirements of the Securities Act of 1933, as amended under Section 4(2) thereof. The Class D common units converted into common units without the payment of further consideration on a one-for-one basis on February 9, 2009.

Distributions. The partnership agreement requires the distribution of all of the Partnership's Available Cash (defined below) within 45 days after the end of each quarter to unitholders of record on the applicable record date, as determined by the General Partner.

Available Cash. Available Cash, for any quarter, generally consists of all cash and cash equivalents on hand at the end of that quarter less the amount of cash reserves established by the general partner to: (i) provide for the proper conduct of the Partnership's business; (ii) comply with applicable law, any debt instruments or other agreements; or (iii) provide funds for distributions to the unitholders and to the General Partner for any one or more of the next four quarters and plus, all cash on hand on that date of determination of available cash for the quarter resulting from working capital borrowings made after the end of the quarter for which the determination is being made.

Distributions of Available Cash. The partnership agreement requires that it make distributions of Available Cash from operating surplus for any quarter after the subordination period in the following manner:

- first, 98 percent to all unitholders, pro rata, and 2 percent to the General Partner, until each unitholder receives a total of $0.35 per unit for that quarter;
- second, 98 percent to all unitholders, pro rata, and 2 percent to the General Partner, until each unitholder receives a total of $0.4025 per unit for that quarter;
- third, 85 percent to all unitholders, pro rata, 13 percent to holders of the incentive distribution rights, and 2 percent to the General Partner, until the aggregate distributions equal $0.4375 per unit outstanding for that quarter;
- fourth, 75 percent to all unitholders, pro rata, 23 percent to holders of the incentive distribution rights, and 2 percent to the General Partner, until the aggregate distributions equal $0.525 per unit outstanding for that quarter; and
- thereafter, 50 percent to all unitholders, pro rata, 48 percent to holders of the incentive distribution rights, and 2 percent to the General Partner.

The Partnership made the following cash distributions per unit during the years ended December 31, 2009 and 2008:

Distribution Date	Cash Distribution (per Unit)
November 13, 2009	$ 0.445
August 14, 2009	0.445
May 14, 2009	0.445
February 13, 2009	0.445
November 14, 2008	0.445
August 14, 2008	0.445
May 14, 2008	0.420
February 14, 2008	0.400

4. Acquisitions and Dispositions

2009

HPC. In March 2009, the Partnership completed a joint venture arrangement among Regency Haynesville Intrastate Gas LLC ("Regency HIG"), a wholly owned subsidiary of the Partnership, EFS Haynesville LLC ("EFS Haynesville"), a wholly owned subsidiary of GECC, and Alinda Gas Pipelines I. L.P. and Alinda Gas Pipelines II. L.P. (collectively the "Alinda Investors"). The Partnership contributed RIG, which owns the Regency Intrastate Gas System ("RIGS"), with a fair value of $401,356,000, to HPC, in exchange for a 38 percent interest in HPC. EFS Haynesville and Alinda Investors contributed $126,928,000 and $528,284,000 in cash, respectively, to HPC in return for a 12 percent and a 50 percent interest, respectively. The disposition and deconsolidation resulted in the recording of a $133,451,000 gain (of which $52,813,000 represents the remeasurement of the Partnership's retained 38 percent interest to its fair value), net of transaction costs of $5,530,000.

In September 2009, the Partnership purchased a five percent interest in HPC from EFS Haynesville for $63,000,000, increasing the Partnership's ownership percentage from 38 percent to 43 percent. Because the transaction occurred between two entities under common control, the Partnership's general partner interest was reduced by $10,197,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount.

2008

FrontStreet. In January 2008, the Partnership completed the FrontStreet Acquisition. FrontStreet owned a gas gathering system located in Kansas and Oklahoma, which is operated by a third party. The total purchase price consisted of (a) 4,701,034 Class E common units of the Partnership issued to ASC in exchange for its 95 percent interest and (b) $11,752,000 in cash to EnergyOne in exchange for its five percent minority interest and the termination of a management services contract valued at $3,888,000. The Partnership financed the cash portion of the purchase price with borrowings under its revolving credit facility.

Because the acquisition of ASC's 95 percent interest was a transaction between commonly controlled entities, the Partnership accounted for this portion of the acquisition in a manner similar to the pooling of interest method. Information included in these financial statements is presented as if the FrontStreet Acquisition had been combined throughout the periods presented in which common control existed, June 18, 2007 forward. Conversely, the acquisition of the five percent minority interest is a transaction between independent parties, for which the Partnership applied the purchase method of accounting.

The following table summarizes the book value of the assets acquired and the liabilities assumed at the date of common control, following the as if pooled method of accounting.

	At June 18, 2007 (in thousands)
Current assets	$ 8,840
Property, plant and equipment	91,556
Total assets acquired	100,396
Current liabilities	(12,556)
Net book value of assets acquired	$ 87,840

CDM Resource Management, Ltd. In January 2008, the Partnership acquired CDM by (a) issuing an aggregate of 7,276,506 Class D common units of the Partnership, which were valued at $219,590,000 and (b) paying an aggregate of $478,445,000 in cash, $316,500,000 of which was used to retire CDM's debt obligations.

The total purchase price of $699,841,000, including direct transaction costs, was allocated as follows.

	At January 15, 2008 (in thousands)
Current assets	$ 19,463
Other assets	4,658
Gas plants and buildings	1,528
Gathering and transmission systems	420,974
Other property, plant and equipment	2,728
Construction-in-process	36,239
Identifiable intangible assets	80,480
Goodwill	164,882
Assets acquired	730,952
Current liabilities	(31,054)
Other liabilities	(57)
Net assets acquired	$ 699,841

Nexus Gas Holdings, LLC ("Nexus"). In March 2008, the Partnership acquired Nexus ("Nexus Acquisition") for $88,486,000 in cash. The Partnership funded the Nexus Acquisition through borrowings under its existing credit facility.

The total purchase price of $88,640,000 was allocated as follows.

	At March 25, 2008 (in thousands)
Current assets	$ 3,457
Buildings	13
Gathering and transmission systems	16,960
Other property, plant and equipment	4,440
Identifiable intangible assets	61,100
Goodwill	3,341
Assets acquired	89,311
Current liabilities	(671)
Net assets acquired	$ 88,640

2007

Palafox Joint Venture. The Partnership acquired the outstanding interest in the Palafox Joint Venture not owned (50 percent) for $5,000,000 effective February 1, 2007. The Partnership allocated $10,057,000 to gathering and transmission systems in the three months ended March 31, 2007. The allocated amount consists of the investment in unconsolidated subsidiary of $5,650,000 immediately prior to the Partnership's acquisition and the Partnership's $5,000,000 purchase of the remaining interest offset by $593,000 of working capital accounts acquired.

Significant Asset Dispositions. The Partnership sold selected non-core pipelines, related rights of way and contracts located in south Texas for $5,340,000 on March 31, 2007 and recorded a loss on sale of $1,808,000. Additionally, the Partnership sold two small gathering systems and associated contracts located in the Mid-continent region for $1,750,000 on May 31, 2007 and recorded a loss on the sale of $469,000. The Partnership also sold its 34 mile NGL pipeline located in east Texas for $3,000,000 on June 29, 2007 and simultaneously entered into transportation and operating agreements with the buyer. The Partnership accounted for this transaction as a sale-leaseback whereby the $3,000,000 gain was deferred and will be amortized to earnings over a 20 year period. The Partnership recorded $3,000,000 in gathering and transmission systems and the related obligations under capital lease. On August 31, 2007, the Partnership sold an idle processing plant for $1,300,000 and recorded a $740,000 gain.

Acquisition of Pueblo Midstream Gas Corporation. In April 2007, the Partnership and its indirect wholly-owned subsidiary, Pueblo Holdings, acquired all the outstanding equity of Pueblo Midstream Gas Corporation ("Pueblo"). The purchase price for the Pueblo acquisition consisted of (1) the issuance of 751,597 common units of the Partnership to the members, valued at $19,724,000 and (2) the payment of $34,855,000 in cash, exclusive of outstanding Pueblo liabilities of $9,822,000 and certain working capital amounts acquired of $108,000. The cash portion of the consideration was financed out of the proceeds of the Partnership's credit facility.

The Pueblo acquisition offered the opportunity to reroute gas to one of the Partnership's existing gas processing plants to provide cost savings. The total purchase price was allocated as follows based on estimates of the fair values of assets acquired and liabilities assumed.

	At April 2, 2007 (in thousands)
Current assets	$ 1,295
Gas plants and buildings	8,994
Gathering and transmission systems	13,079
Other property, plant and equipment	180
Intangible assets subject to amortization (contracts)	5,242
Goodwill	36,523
Assets acquired	65,313
Current liabilities	(1,187)
Long-term liabilities	(9,492)
Total Purchase price	$ 54,634

The following unaudited pro forma financial information has been prepared as if the acquisitions of FrontStreet, CDM, Nexus and Pueblo, as well as the contribution of RIG to HPC as well as the acquisition of additional five percent HPC interest had occurred as of the beginning of the earliest period presented. Such unaudited pro forma financial information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the date referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the Year Ended December 31,		
	2009	2008	2007
	(in thousands except unit and per unit data)		
Revenue	$ 1,077,524	$ 1,822,722	$ 1,274,829
Net income	5,935	82,003	112,779
Less: Amount allocated to noncontrolling interest	(3,450)	(78,234)	(110,799)
Net income attributable to Regency GP LP	$ 2,485	$ 3,769	$ 1,980

5. Investment in Unconsolidated Subsidiary

As described in the Acquisitions and Dispositions footnote, the Partnership contributed RIG to HPC for a 38 percent partner's interest in HPC. Subsequently, on September 2, 2009, the Partnership purchased an additional five percent partner's interest in HPC from EFS Haynesville for $63,000,000. The Partnership recognized $7,886,000 in income from unconsolidated subsidiary for its ownership interest and received $8,926,000 of distributions from HPC from inception (March 18, 2009) to December 31, 2009. The summarized financial information of HPC for the period from inception (March 18, 2009) to December 31, 2009 is disclosed below.

RIGS Haynesville Partnership Co.
Condensed Consolidated Balance Sheet
December 31, 2009
(in thousands)

ASSETS	
Total current assets	$ 39,239
Restricted cash, non-current	33,595
Property, plant and equipment, net	861,570
Total other assets	149,755
TOTAL ASSETS	$1,084,159
LIABILITIES & PARTNERS' CAPITAL	
Total current liabilities	$ 30,967
Partners' capital	1,053,192
TOTAL LIABILITIES & PARTNERS' CAPITAL	$1,084,159

RIGS Haynesville Partnership Co.
Condensed Consolidated Income Statement
From Inception (March 18, 2009) to December 31, 2009
(in thousands)

Total revenues	$43,483
Total operating costs and expenses	24,926
OPERATING INCOME	18,557
Interest expense	(158)
Other income and deductions, net	1,335
NET INCOME	$19,734

The HPC partnership agreement requires the distribution of 100 percent of "available cash" to the partners in accordance with their sharing ratios within 30 days after the end of each calendar quarter. Available cash is defined as cash on hand (excluding cash restricted for the Haynesville Expansion Project), less amounts reserved for normal operating expenses.

6. Derivative Instruments

Policies. The Partnership established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Risk Management Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operation. The prices of these commodities are impacted by changes in the supply and demand as well as market focus. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. It is the Partnership's policy not to take any speculative positions with its derivative contracts.

The Partnership has executed swap contracts settled against NGLs (ethane, propane, butane, and natural gasoline), condensate and natural gas market prices for expected exposure in the approximate percentages set for below.

	As of December 31, 2009	
	2010	2011
NGLs	80%	33%
Condensate	84%	21%
Natural gas	85%	27%

At December 31, 2009, the 2010 and 2011 natural gas and 2010 condensate swaps are accounted for as cash flow hedges; the 2011 condensate swaps are accounted for using mark-to-market accounting; and the 2010 and 2011 NGLs swaps are accounted for using a combination of cash flow hedge accounting and mark-to-market accounting.

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its credit facility. As of December 31, 2009, the Partnership had $419,642,000 of outstanding borrowings exposed to variable interest rate risk. In February 2008, the Partnership entered into two-year interest rate swaps related to $300,000,000 of borrowings under its credit facility, effectively locking the base rate for these borrowings at 2.4 percent, plus the applicable margin (3.0 percent as of December 31, 2009) through March 5, 2010. These interest rate swaps were designated as cash flow hedges.

Credit Risk. The Partnership's resale of natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances any such extension of credit is backed by adequate collateral such as a letter of credit or a guarantee from a parent company with potentially better credit.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives. The Partnership has entered into Master International Swap Dealers Association ("ISDA") Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties failed to perform under existing swap contracts, the Partnership's maximum loss is $25,246,000, which would be reduced by $13,284,000 due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the consolidated balance sheets.

Embedded Derivatives. The Partnership's Series A Convertible Redeemable Preferred Units ("Series A Preferred Units") contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. Changes in the fair value are recorded in other income and deductions, net within the consolidated statement of operations. The Partnership does not expect the embedded derivatives to affect its cash flows. During the year ended December 31, 2009, the loss recognized related to these embedded derivatives was $15,686,000 and is reflected in other income and deductions, net on the consolidated statement of operations.

Quantitative Disclosures. On May 26, 2010, the Partnership's accumulated other comprehensive income was adjusted to its fair value, which was $0, as a result of a change in control in the General Partner. For more information about the change in control, see Note 17.

The Partnership's derivative assets and liabilities, including credit risk adjustment, for the years ending December 31, 2009 and 2008 are detailed below.

	Assets		Liabilities	
	December 31, 2009	December 31, 2008	December 31, 2009	December 31, 2008
	(in thousands)			
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$ —	$ —	$ 1,067	$ 4,680
Commodity contracts	9,525	59,882	11,200	—
Long-term amounts				
Interest rate contracts	—	—	—	560
Commodity contracts	207	13,373	931	—
Total cash flow hedging instruments	9,732	73,255	13,198	5,240
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	15,514	16,001	31	38,402
Long-term amounts				
Commodity contracts	—	23,425	3,378	—
Embedded derivatives in Series A Preferred Units	—	—	44,594	—
Total derivatives not designated as cash flow hedges	15,514	39,426	48,003	38,402
Credit Risk Assessment				
Current amounts	(52)	(1,890)	(42)	(391)
Total derivatives	$ 25,194	$ 110,791	$ 61,159	$ 43,251

Derivatives designated as cash flow hedges

	Year Ended December 31, 2009			Year Ended December 31, 2008		
	Interest Rate	Commodity	Total	Interest Rate	Commodity	Total
	(in thousands)					
Gain (loss) recorded in accumulated OCI (Effective)	$ (2,082)	$ (19,958)	$ (22,040)	$ (4,555)	$ 74,808	$ 70,253
Gain (loss) reclassified from accumulated OCI into income (Effective)*	(6,255)	54,260	48,005	676	(35,942)	(35,266)
Gain (loss) recognized in income (Ineffective)*	—	108	108	—	543	543

Derivatives not designated as cash flow hedges

	Year Ended December 31, 2009			Year Ended December 31, 2008		
	Embedded Derivatives	Commodity	Total	Embedded Derivatives	Commodity	Total
	(in thousands)					
Loss from dedesignation amortized from accumulated OCI into income*	$ —	$ (611)	$ (611)	$ —	$ (246)	$ (246)
(Loss) gain recognized in income*	(15,686)	(13,669)	(29,355)	—	15,911	15,911

Credit risk assessment for commodity and interest rate swaps

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Gain (loss) recognized in income*	$ 1,489	$ (1,499)	$ —

* Gain and loss related to commodity swaps, interest swaps and embedded derivatives were included in revenue, interest expense, and other income and deductions, net, respectively, in the Partnership's consolidated statements of operations.

7. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facilities are as follows.

	December 31, 2009	December 31, 2008
	(in thousands)	
Senior notes	$ 594,657	$ 357,500
Revolving loans	419,642	768,729
Total	1,014,299	1,126,229
Less: current portion	—	—
Long-term debt	$ 1,014,299	$ 1,126,229
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded Lehman commitments	(10,675)	(8,646)
Revolving loans	(419,642)	(768,729)
Letters of credit	(16,257)	(16,257)
Total available	$ 453,426	$ 106,368

Long-term debt maturities as of December 31, 2009 for each of the next five years are as follows.

Year Ended December 31,	Amount (in thousands)
2010	$ —
2011	419,642
2012	—
2013	357,500
2014	—
Thereafter	250,000*
Total	$ 1,027,142

* As of December 31, 2009, the carrying value of the senior notes due 2016 was $237,157,000 which included an unamortized discount of $12,843,000.

In the year ended December 31, 2009, the Partnership borrowed $191,693,000 under its credit facility; these borrowings were primarily to fund capital expenditures. During the same period, the Partnership repaid $540,780,000 with proceeds from an equity offering and issuance of senior notes due 2016. In the years ended December 31, 2008 and 2007, the Partnership borrowed $844,729,000 and $283,230,000, respectively; these funds were used primarily to finance capital expenditures. During the same periods, the Partnership repaid $200,000,000 and $421,430,000, respectively, of these borrowings with proceeds from equity offerings.

Senior Notes due 2016. In May 2009, the Partnership and Finance Corp. issued $250,000,000 of senior notes in a private placement that mature on June 1, 2016. The senior notes bear interest at 9.375 percent with interest payable semi-annually in arrears on June 1 and December 1. The Partnership paid a $13,760,000 discount upon issuance. The net proceeds were used to partially repay revolving loans under the Partnership's credit facility.

At any time before June 1, 2012, up to 35 percent of the senior notes can be redeemed at a price of 109.375 percent plus accrued interest. Beginning June 1, 2013, the Partnership may redeem all or part of these notes for the principal amount plus a declining premium until June 1, 2015, and thereafter at par, plus accrued and unpaid interest. At any time prior to June 1, 2013, the Partnership may also redeem all or part of the notes at a price equal to 100 percent of the principal amount of notes redeemed plus accrued interest and the applicable premium, which equals to the greater of (1) one percent of the principal amount of the note; or (2) the excess of the present value at such redemption date of (i) the redemption price of the note at June 1, 2013 plus (ii) all required interest payments due on the note through June 1, 2013, computed using a discount rate equal to the treasury rate (as defined) as of such redemption date plus 50 basis points over the principal amount of the note.

Upon a change of control, each noteholder may, at its option, require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages, if any. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of its debt agreements, including its credit facility. As disclosed in Note 17, a change in control of the General Partner occurred effective May 26, 2010. Subsequent to this change in control, no noteholder has exercised this option.

The senior notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;

- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the senior notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At December 31, 2009, the Partnership was in compliance with these covenants.

The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Finance Corp., and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's credit facility, to the extent of the value of the assets securing such obligations.

Senior Notes due 2013. In 2006, the Partnership and Finance Corp. issued $550,000,000 senior notes that mature on December 15, 2013 in a private placement. The senior notes bear interest at 8.375 percent and interest is payable semi-annually in arrears on each June 15 and December 15. In August 2007, the Partnership exercised its option to redeem 35 percent or $192,500,000 of these senior notes at a price of 108.375 percent of the principal amount plus accrued interest. Accordingly, a redemption premium of $16,122,000 and a loss on debt refinancing and unamortized loan origination costs of $4,575,000 were charged to loss on debt refinancing in the year ended December 31, 2007. Under the senior notes terms, no further redemptions are permitted until December 15, 2010.

The Partnership may redeem the outstanding senior notes, in whole or in part, at any time on or after December 15, 2010, at a redemption price equal to 100 percent of the principal amount thereof, plus a premium declining ratably to par and accrued and unpaid interest and liquidated damages, if any, to the redemption date.

Upon a change of control, each noteholder may, at its option, require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages, if any. The Partnership's ability to purchase the notes upon a change of control will be limited by the terms of its debt agreements, including its credit facility. As disclosed in Note 17, a change in control of the General Partner occurred effective May 26, 2010. Subsequent to this change in control, no noteholder has exercised this option.

The senior notes contain various covenants that limit, among other things, the Partnership's ability, and the ability of certain of its subsidiaries, to:

- incur additional indebtedness;
- pay distributions on, or repurchase or redeem equity interests;
- make certain investments;
- incur liens;
- enter into certain types of transactions with affiliates; and
- sell assets, consolidate or merge with or into other companies.

If the senior notes achieve investment grade ratings by both Moody's and S&P and no default or event of default has occurred and is continuing, the Partnership will no longer be subject to many of the foregoing covenants. At December 31, 2009, the Partnership was in compliance with these covenants.

The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Regency Energy Finance Corp. ("Finance Corp."), a wholly owned subsidiary of the Partnership, and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's credit facility, to the extent of the value of the assets securing such obligations.

Finance Corp. has no operations and will not have revenue other than as may be incidental as co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except certain wholly owned subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

GECC Credit Facility. On February 26, 2009, the Partnership entered into a $45,000,000 unsecured revolving credit agreement with GECC. The proceeds of the GECC Credit Facility were available for expenditures made in connection with the Haynesville Expansion Project prior to the effectiveness of the March 17, 2009 amendment discussed below. The commitments under the GECC Credit Facility terminated on March 17, 2009. The Partnership paid a commitment fee of $2,718,000 to GECC related to this GECC Credit Facility, which was recorded as a decrease to gain on asset sales, net.

Fourth Amended and Restated Credit Agreement. In February 2008, Regency Gas Services LP ("RGS")'s Fourth Amended and Restated Credit Agreement was expanded to $900,000,000 and the availability for letters of credit was increased to $100,000,000. The Partnership also has the option to request an additional $250,000,000 in revolving commitments with ten business days written notice provided that no event of default has occurred or would result due to such increase, and all other additional conditions for the increase of the commitments set forth in the credit facility have been met. The maturity date of the Credit Facility is August 15, 2011.

Effective March 17, 2009, RGS amended the credit facility to authorize the contribution of RIG to HPC and allow for a future investment of up to $135,000,000 in HPC. The amendment imposed additional financial restrictions that limit the ratio of senior secured indebtedness to EBITDA. The alternate base rate used to calculate interest on base rate loans will be calculated based on the greatest to occur of a base rate, a federal funds effective rate plus 0.50 percent and an adjusted one-month LIBOR rate plus 1.50 percent. The applicable margin shall range from 1.50 percent to 2.25 percent for base rate loans, 2.50 percent to 3.25 percent for Eurodollar loans, and a commitment fee will range from 0.375 to 0.500 percent. On July 24, 2009, RGS further amended its credit facility to allow for a $25,000,000 working capital facility for RIG. These amendments did not materially change other terms of the RGS revolving credit facility.

On September 15, 2008, Lehman Brothers Holdings, Inc. ("Lehman") filed a petition in the United States Bankruptcy Court seeking relief under Chapter 11 of the United States Bankruptcy Code. As a result, a subsidiary of Lehman that is a committed lender under the Partnership's credit facility has declined requests to honor its commitment to lend. The total amount committed by Lehman was $20,000,000 and as of December 31, 2009, the Partnership had borrowed all but $10,675,000 of that amount. Since Lehman has declined requests to honor its remaining commitment, the Partnership's total size of the credit facility's capacity has been reduced from $900,000,000 to $889,325,000. Further, if the Partnership makes repayments of loans against the credit facility which were, in part, funded by Lehman, the amounts funded by Lehman may not be reborrowed.

The outstanding balance of revolving loans under the credit facility bears interest at the London Interbank Offered Rate ("LIBOR") plus a margin or Alternative Base Rate (equivalent to the U.S. prime lending rate) plus a margin, or a combination of both. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 6.69 percent, 6.27 percent, and 8.78 percent for the years ended December 31, 2009, 2008, and 2007, respectively. The senior notes pay fixed interest rates and the weighted average rate is 8.787 percent.

RGS must pay (i) a commitment fee equal to 0.50 percent per annum of the unused portion of the revolving loan commitments, (ii) a participation fee for each revolving lender participating in letters of credit equal to 3.0 percent per annum of the average daily amount of such lender's letter of credit exposure, and (iii) a fronting fee to the issuing bank of letters of credit equal to 0.125 percent per annum of the average daily amount of the letter of credit exposure.

The credit facility contains financial covenants requiring RGS and its subsidiaries to maintain debt to adjusted EBITDA (as defined in the credit agreement) ratio less than 5.25, and adjusted EBITDA to interest expense ratio greater than 2.75 times. At December 31, 2009 and 2008, RGS and its subsidiaries were in compliance with these covenants.

The credit facility restricts the ability of RGS to pay dividends and distributions other than reimbursements of the Partnership for expenses and payment of dividends to the Partnership to the extent of the Partnership's determination of available cash (so long as no default or event of default has occurred or is continuing). The credit facility also contains various covenants that limit (subject to certain exceptions and negotiated baskets), among other things, the ability of RGS to:

- incur indebtedness;
- grant liens;
- enter into sale and leaseback transactions;
- make certain investments, loans and advances;
- dissolve or enter into a merger or consolidation;
- enter into asset sales or make acquisitions;
- enter into transactions with affiliates;
- prepay other indebtedness or amend organizational documents or transaction documents (as defined in the credit facility);
- issue capital stock or create subsidiaries; or
- engage in any business other than those businesses in which it was engaged at the time of the effectiveness of the credit facility or reasonable extensions thereof.

8. Other Assets

Intangible assets, net. Intangible assets, net consist of the following.

	Permits and Licenses	Contracts	Trade Names (in thousands)	Customer Relations	Total
Balance at January 1, 2008	$ 9,368	$ 68,436	$ —	$ —	$ 77,804
Additions	—	64,770	35,100	41,710	141,580
Amortization	(786)	(6,407)	(2,252)	(4,293)	(13,738)
Balance at December 31, 2008	8,582	126,799	32,848	37,417	205,646
Disposals	(2,921)	—	—	—	(2,921)
Other	—	7,000	—	—	7,000
Amortization	(569)	(7,467)	(2,340)	(2,055)	(12,431)
Balance at December 31, 2009	$ 5,092	$126,332	$ 30,508	$ 35,362	$197,294

The average remaining amortization periods for permits and licenses, contracts, trade names, and customer relations are 10, 16, 13 and 18 years, respectively. As of December 31, 2009 the expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2010	$ 12,553
2011	11,244
2012	11,002
2013	11,002
2014	11,002

Goodwill. Goodwill activity consists of the following.

	Gathering and Processing	Transportation	Contract Compression (in thousands)	Total
Balance at January 1, 2008	$ 59,831	$ 34,244	$ —	$ 94,075
Additions	3,401	—	164,882	168,283
Balance at December 31, 2008	63,232	34,244	164,882	262,358
Disposals	—	(34,244)	—	(34,244)
Balance at December 31, 2009	$ 63,232	$ —	$ 164,882	$228,114

On March 17, 2009, the Partnership contributed all assets of RIG, which owns RIGS, to HPC, in exchange for an interest in HPC. As a result, goodwill associated with the transportation segment was removed from the balance sheet.

9. Fair Value Measures

On January 1, 2008, the Partnership adopted the fair value measurement provisions for financial assets and liabilities and on January 1, 2009, the Partnership applied the fair value measurement provisions to non-financial assets and liabilities, such as goodwill, indefinite-lived intangible assets, property, plant and equipment and asset retirement obligations. These provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2—inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

Derivatives. The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to interest rate and commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to interest rate and commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy. The change in fair value of the derivatives related to Series A Preferred Units is recorded in other income and deductions, net within the statement of operations.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis.

	December 31, 2009		December 31, 2008	
	Assets	Liabilities	Assets	Liabilities
	(in thousands)			
Level 1	$ —	$ —	$ —	$ —
Level 2	25,194	16,565	110,791	43,251
Level 3	—	44,594	—	—
Total	$25,194	$61,159	$110,791	$43,251

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the year ended December 31, 2009. There were no Level 3 derivatives for the years ended December 31, 2008 or 2007.

	Derivatives related to Series A Preferred Units For the Year Ended December 31, 2009 (in thousands)
Beginning Balance	$ —
Issuance	28,908
Net unrealized losses included in other income and deductions, net	15,686
Ending Balance	$ 44,594

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. Long-term debt, other than the senior notes, is comprised of borrowings under which, interest accrues under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair value of the senior notes due 2013 based on third party market value quotations as of December 31, 2009 and 2008 was $364,650,000 and $244,888,000, respectively. The estimated fair value of the senior notes due 2016 based on third party market value quotations as of December 31, 2009 was $265,625,000.

10. Leases

The Partnership leases office space and certain equipment and the following table is a schedule of future minimum lease payments for leases that had initial or remaining noncancelable lease terms in excess of one year as of December 31, 2009.

For the year ending December 31,	Operating	Capital
	(in thousands)	
2010	$ 3,838	$ 589
2011	3,801	422
2012	3,426	436
2013	2,714	448
2014	2,351	462
Thereafter	9,975	7,101
Total minimum lease payments	$26,105	$9,458
Less: Amount representing estimated executory costs (such as maintenance and insurance), including profit thereon, included in minimum lease payments		1,890
Net minimum lease payments		7,568
Less: Amount representing interest		4,365
Present value of net minimum lease payments		$3,203

The following table sets forth the Partnership's assets and obligations under the capital lease which are included in other current and long-term liabilities on the consolidated balance sheet.

	December 31, 2009 (in thousands)
Gross amount included in gathering and tranmission systems	$ 3,000
Gross amount included in other property, plant and equipment	560
Less accumulated depreciation	(755)
	$ 2,805
Current obligation under capital lease	529
Non-current obligation under capital lease	2,674
	$ 3,203

Total rent expense for operating leases, including those leases with terms of less than one year, was $5,465,000, $2,576,000, and $1,597,000, for the years ended December 31, 2009, 2008, and 2007, respectively.

11. Commitments and Contingencies

Legal. The Partnership is involved in various claims and lawsuits incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Escrow Payable. At December 31, 2009, $1,511,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area and a subsequent 2008 settlement agreement between the Partnership and El Paso. In the El Paso PSA, El Paso indemnified Regency Gas Services LLC, now known as Regency Gas Services LP, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion.

Environmental . A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made against the Partnership or under the policy.

TCEQ Notice of Enforcement. In February 2008, the TCEQ issued a Notice of Enforcement ("NOE") concerning one of the Partnership's processing plants located in McMullen County, Texas. The NOE alleged that, between March 9, 2006, and May 8, 2007, this plant experienced 15 emission events of various durations from four hours to 41 days, which were not reported to TCEQ and other agencies within 24 hours of occurrence. In January 2010, the TCEQ notified the Partnership in writing that it had concluded that there had been no violation and that the TCEQ would take no further action.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership's predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. Discovery ended in October 2009. A hearing on cross-motions for summary judgment took place in December 2009. A decision is expected in the first quarter of 2010. If the Partnership does not win its motion, a jury trial is scheduled for April 2010.

Kansas State Severance Tax. In August 2008, a customer began remitting severance tax to the state of Kansas based on the value of condensate purchased from one of the Partnership's Mid-Continent gathering fields and deducting the tax from its payments to the Partnership. The Kansas Department of Revenue advised the customer that it was appropriate to remit such taxes and withhold the taxes from its payments to the Partnership, absent an order or legal opinion from the Kansas Department of Revenue stating otherwise. The Partnership has requested a determination from the Kansas Department of Revenue regarding the matter since severance taxes were already paid on the gas from which the condensate is collected and no additional tax is due. The Kansas Department of Revenue has initiated an audit of the Partnership's condensate sales in Kansas. If the Kansas Department of Revenue determines that the condensate sales are taxable, then the Partnership may be subject to additional taxes, interest and possible penalties for past and future condensate sales.

Caddo Gas Gathering LLC v. Regency Intrastate Gas LLC. Regency Intrastate Gas LLC was a defendant in a lawsuit filed by Caddo Gas Gathering LLC ("Caddo Gas"). In February 2010, the dispute was resolved and the lawsuit dismissed with prejudice without material expense.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. Regency Field Services LLC ("RFS") currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the "Plants"). The Plants each have a groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from El Paso, Kerr-McGee Corporation ("Kerr-McGee") was performing remediation of the groundwater contamination, because the Plants were once owned by Kerr-McGee and when Kerr-McGee sold the Plants to a predecessor of El Paso in 1988, Kerr-McGee retained liability for any environmental contamination at the Plants. In 2005, Kerr-McGee created and spun off Tronox and Tronox allegedly assumed certain of Kerr-McGee's environmental remediation obligations (including its obligation to perform remediation at the Plants) prior to the acquisition of Kerr-McGee by Anadarko Petroleum Corporation. In January 2009, Tronox filed for Chapter 11 bankruptcy protection. RFS filed a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants. Tronox has thus far continued its remediation efforts at the Plants.

12. Series A Convertible Redeemable Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units at a price of $18.30 per unit, less a four percent discount of $3,200,000 and issuance costs of $176,000 for net proceeds of $76,624,000, exclusive of the General Partner's contribution of $1,633,000. The Series A Preferred Units are convertible to common units under terms described below, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon (the "Series A Liquidation Value"). The Series A Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010.

Distributions on the Series A Preferred Units will be accrued for the first two quarters (and not paid in cash) and will result in an increase in the number of common units issuable upon conversion. For the year ended December 31, 2009, total accrued distributions per unit was $0.89. If on any distribution payment date beginning March 31, 2010, the Partnership (1) fails to pay distributions on the Series A Preferred Units, (2) reduces the distributions on the common units to zero and (3) is prohibited by its material financing agreements from paying cash distributions, such distributions shall automatically accrue and accumulate until paid in cash. If the Partnership has failed to pay cash distributions in full for two quarters (whether or not consecutive) from and including the quarter ending on March 31, 2010, then if the Partnership fails to pay cash distributions on the Series A Preferred Units, all future distributions on the Series A Preferred Units that are accrued rather than being paid in cash by the Partnership will consist of the following: (1) $0.35375 per Series A Preferred Unit per quarter, (2) $0.09125 per Series A Preferred Unit per quarter (the "Common Unit Distribution Amount"), payable solely in common units, and (3) $0.09125 per Series A Preferred Unit per quarter (the "PIK Distribution Additional Amount"), payable solely in common units. The total number of common units payable in connection with the Common Unit Distribution Amount or the PIK Distribution Additional Amount cannot exceed 1,600,000 in any period of 20 consecutive fiscal quarters.

Upon the Partnership's breach of certain covenants (a "Covenant Default"), the holders of the Series A Preferred Units will be entitled to an increase of $0.1825 per quarterly distribution, payable solely in common units (the "Covenant Default Additional Amount"). All accumulated and unpaid distributions will accrue interest (i) at a rate of 2.432 percent per quarter, or (ii) if the Partnership has failed to pay all PIK Distribution Additional Amounts or Covenant Default Additional Amounts or any Covenant Default has occurred and is continuing, at a rate of 3.429 percent per quarter while such failure to pay or such Covenant Default continues.

The Series A Preferred Units are convertible, at the holder's option, into common units commencing on March 2, 2010, provided that the holder must request conversion of at least 375,000 Series A Preferred Units. The conversion price will initially be $18.30, subject to adjustment for customary events (such as unit splits) and until December 31, 2011, based on a weighted average formula in the event the Partnership issues any common units (or securities convertible or exercisable into common units) at a per common unit price below $16.47 per common unit (subject to typical exceptions). The number of common units issuable is equal to the issue price of the Series A Preferred Units (i.e. $18.30) being converted plus all accrued but unpaid distributions and accrued but unpaid interest thereon (the "Redeemable Face Amount"), divided by the applicable conversion price.

Commencing on September 2, 2014, if at any time the volume-weighted average trading price of the common units over the trailing 20-trading day period (the "VWAP Price") is less than the then-applicable conversion price, the conversion ratio will be increased to: the quotient of (1) the Redeemable Face Amount on the date that the holder's conversion notice is delivered, divided by (2) the product of (x) the VWAP Price set forth in the applicable conversion notice and (y) 91 percent, but will not be less than $10.

Also commencing on September 2, 2014, the Partnership will have the right at any time to convert all or part of the Series A Preferred Units into common units, if (1) the daily volume-weighted average trading price of the common units is greater than 150 percent of the then-applicable conversion price for twenty (20) out of the trailing thirty (30) trading days, and (2) certain minimum public float and trading volume requirements are satisfied.

In the event of a change of control, the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 101 percent of their Series A Liquidation Value. In addition, in the event of certain business combinations or other transactions involving the Partnership in which the holders of common units receive cash consideration exclusively in exchange for their common units (a "Cash Event"), the Partnership must use commercially reasonable efforts to ensure that the holders of the Series A Preferred Units will be entitled to receive a security issued by the surviving entity in the Cash Event with comparable powers, preferences and rights to the Series A Preferred Units. If the Partnership is unable to ensure that the holders of the Series A Preferred Units will be entitled to receive such a security, then the Partnership will be required to make an offer to the holders of the Series A Preferred Units to purchase their Series A Preferred Units for an amount equal to 120 percent of their Series A Liquidation Value. If the Partnership enters into any recapitalization, reorganization, consolidation, merger, spin-off that is not a Cash Event, the Partnership will make appropriate provisions to ensure that the holders of the Series A Preferred Units receive a security with comparable powers, preferences and rights to the Series A Preferred Units upon consummation of such transaction. As disclosed in Note 17, a change in control of the General Partner occurred on May 26, 2010. Subsequent to the change in control no holders of these units have exercised this option.

As of December 31, 2009, accrued distributions of $3,891,000 have been added to the value of the Series A Preferred Units and increases the number of common units to 4,584,192 that may be issued upon conversion. Holders may elect to convert Series A Preferred Units to common units beginning on March 2, 2010.

Net proceeds from the issuance of Series A Preferred Units on September 2, 2009 was $76,624,000, of which $28,908,000 was allocated to the initial fair value of the embedded derivatives and recorded into long-term derivative liabilities on the balance sheet. The remaining $47,716,000 represented the initial value of the Series A Preferred Units and will be accreted to $80,000,000 by deducting the accretion amounts from partners' capital over 20 years.

The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for all income statement periods presented.

	Units	Amount (in thousands)
Beginning balance as of January 1, 2009	—	$ —
Original issuance, net of discount of $3,200	4,371,586	76,624
Amount reclassed to long-term derivative liabilities	—	(28,908)
Accrued distributions	—	3,891
Accretion to redemption value	—	104
Ending balance as of December 31, 2009	4,371,586	$ 51,711

13. Related Party Transactions

In September 2008, HM Capital Partners LLC and affiliates sold 7,100,000 common units for total consideration of $149,100,000, reducing their ownership percentage to an amount less than ten percent of the Partnership's outstanding common units. As a result of this sale, HM Capital Partners LLC is no longer a related party of the Partnership. During the years ended December 31, 2008 and 2007, HM Capital Partners LLC and affiliates received cash disbursements, in conjunction with distributions by the Partnership for limited and general partner interests, of $10,308,000 and $24,392,000, respectively.

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $33,834,000, $26,899,000, and $27,628,000, were recorded in the Partnership's financial statements during the years ended December 31, 2009, 2008, and 2007, respectively, as operating expenses or general and administrative expenses, as appropriate.

Concurrent with the GE EFS Acquisition, eight members of the Partnership's senior management, together with two independent directors, entered into an agreement to sell an aggregate of 1,344,551 subordinated units for a total consideration of $24.00 per unit. Additionally, GE EFS entered into a subscription agreement with four officers and certain other management of the Partnership whereby these individuals acquired an 8.2 percent indirect economic interest in the General Partner.

GE EFS and certain members of the Partnership's management made capital contributions aggregating to $6,344,000, $11,746,000 and $7,735,000 to maintain the General Partner's two percent interest in the Partnership for the years ended December 31, 2009, 2008, and 2007, respectively.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS received cash distributions of $51,226,000, $35,054,000, and $14,592,000 during the years ended December 31, 2009, 2008 and 2007, respectively.

As part of the August 1, 2008 common units offering, an affiliate of GECC purchased 2,272,727 common units for total consideration of $50,000,000.

The Partnership's contract compression segment provided contract compression services to CDM MAX LLC ("CDM MAX"). In 2009, CDM MAX was purchased by a third party and, as a result, CDM MAX is no longer a related party. The Partnership's related party revenue associated with CDM MAX was $1,101,000 and $3,712,000 during the years ended December 31, 2009 and 2008, respectively.

Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. Under this agreement the Partnership received $500,000 monthly as a partial reimbursement of its general and administrative costs. The Partnership also incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. For the period from March 18, 2009 to December 31, 2009, the related party general and administrative expenses reimbursed to the Partnership were $4,726,000. On December 18, 2009, the reimbursement amount was amended to $1,400,000 per month effective on the first calendar day in the month subsequent to mechanical completion of the expansion of the Regency Intrastate Gas System (February 1, 2010), subject to an annual escalation beginning March 1, 2011. The amount is recorded as fee revenue in the Partnership's corporate and other segment. Additionally, the Partnership's contract compression segment provides contract compression services to HPC. On the other hand, HPC provides transportation service to the Partnership.

Upon the formation of HPC in March 2009, the Partnership was reimbursed by HPC for construction-in-progress incurred prior to formation of HPC at the cost of $80,608,000. Subsequently, the Partnership sold an additional $7,984,000 of compression equipment to HPC.

The Partnership's related party receivables and related party payables as of December 31, 2009 relate to HPC. The Partnership's related party receivables and related party payables as of December 31, 2008 related to CDM MAX.

As disclosed in Note 1 and in Note 4, the Partnership's acquisition of FrontStreet and contribution of RIGS to HPC are related party transactions.

14. Concentration Risk

The following table provides information about the extent of reliance on major customers and gas suppliers. Total revenues and cost of sales from transactions with an external customer or supplier amounting to ten percent or more of revenue or cost of gas and liquids are disclosed below, together with the identity of the reporting segment.

	Reportable Segment	Year Ended December 31, 2009	December 31, 2008 (in thousands)	December 31, 2007
Customer				
Customer A	Gathering and Processing	$ 123,524	*	*
Supplier				
Supplier A	Transportation	$ 14,053	$ 75,464	$ 17,930
Supplier A	Gathering and Processing	143,435	243,075	139,116

* Amounts are less than ten percent of the total revenue or cost of sales.

The Partnership is a party to various commercial netting agreements that allow it and contractual counterparties to net receivable and payable obligations. These agreements are customary and the terms follow standard industry practice. In the opinion of management, these agreements reduce the overall counterparty risk exposure.

15. Segment Information

In 2009, the Partnership's management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has four reportable segments: (a) gathering and processing, (b) transportation, (c) contract compression and (d) corporate and others. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenue and the associated cost of sales from the gathering and processing segment directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment. The Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

Following the initial contribution of RIG to HPC in March 2009, as well as the subsequent acquisition of an additional five percent interest in HPC, the transportation segment consists exclusively of the Partnership’s 43 percent interest in HPC, for which equity method accounting applies. Prior periods have been restated to reflect the Partnership’s then wholly-owned subsidiary of Regency Intrastate Gas LLC as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with other pipelines, storage facilities or end-use markets. RIG performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenue is primarily fee based and involves minimal direct exposure to commodity price fluctuations. The north Louisiana intrastate pipeline operated by this segment serves the Partnership’s gathering and processing facilities in the same area and those transactions create a portion of the intersegment revenue shown in the table below.

The contract compression segment provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership’s integrated solutions include a comprehensive assessment of a customer’s natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and ongoing operation, service, and repair of its compression units, which are modified as necessary to adapt to customers’ changing operating conditions. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

The corporate and others segment comprises regulated entities and the Partnership’s corporate offices. Revenue in this segment includes the collection of the partial reimbursement of general and administrative costs from HPC.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the gathering and processing and for the transportation segments, is defined as total revenue, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenues minus direct costs, which primarily consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenue generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenue in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Results for each income statement period, together with amounts related to balance sheets for each segment are shown below.

	Gathering and Processing	Transportation	Contract Compression	Corporate and Others	Eliminations	Total
			(in thousands)			
External Revenue						
Year ended December 31, 2009	$ 920,650	$ 9,078	$ 148,846	$ 10,923	$ —	$1,089,497
Year ended December 31, 2008	1,685,946	42,400	132,549	2,909	—	1,863,804
Year ended December 31, 2007	1,151,739	36,587	—	1,912	—	1,190,238
Intersegment Revenue						
Year ended December 31, 2009	(8,755)	4,933	4,604	296	(1,078)	—
Year ended December 31, 2008	42,310	11,422	4,573	339	(58,644)	—
Year ended December 31, 2007	26,165	12,391	—	281	(38,837)	—
Cost of Sales						
Year ended December 31, 2009	681,383	2,297	12,422	(65)	3,526	699,563
Year ended December 31, 2008	1,463,851	(13,066)	11,619	—	(54,071)	1,408,333
Year ended December 31, 2007	1,018,721	(3,570)	—	(169)	(38,837)	976,145
Segment Margin						
Year ended December 31, 2009	230,512	11,714	141,028	11,284	(4,604)	389,934
Year ended December 31, 2008	264,405	66,888	125,503	3,248	(4,573)	455,471
Year ended December 31, 2007	159,183	52,548	—	2,362	—	214,093
Operation and Maintenance						
Year ended December 31, 2009	88,520	2,112	45,744	426	(5,976)	130,826
Year ended December 31, 2008	82,689	3,540	49,799	74	(4,473)	131,629
Year ended December 31, 2007	53,496	4,407	—	97	—	58,000
Depreciation and Amortization						
Year ended December 31, 2009	67,583	2,448	36,548	3,314	—	109,893
Year ended December 31, 2008	58,900	14,099	28,448	1,119	—	102,566
Year ended December 31, 2007	40,309	13,457	—	1,308	—	55,074
Income from Unconsolidated Subsidiary						
Year ended December 31, 2009	—	7,886	—	—	—	7,886
Year ended December 31, 2008	—	—	—	—	—	—
Year ended December 31, 2007	—	—	—	—	—	—
Assets						
December 31, 2009	1,046,619	453,120	926,213	107,463	—	2,533,415
December 31, 2008	1,101,906	325,310	881,552	149,872	—	2,458,640
Investment in Unconsolidated Subsidiary						
December 31, 2009	—	453,120	—	—	—	453,120
December 31, 2008	—	—	—	—	—	—
Goodwill						
December 31, 2009	63,232	—	164,882	—	—	228,114
December 31, 2008	63,232	34,244	164,882	—	—	262,358
Expenditures for Long-Lived Assets						
Year ended December 31, 2009	84,097	22,367	83,707	2,912	—	193,083
Year ended December 31, 2008	124,736	59,231	186,063	5,053	—	375,083
Year ended December 31, 2007	112,813	15,658	—	1,313	—	129,784

The table below provides a reconciliation of total segment margin to net income (loss) from continuing operations.

	Year Ended December 31, 2009	December 31, 2008 (in thousands)	December 31, 2007
Net income (loss) attributable to Regency GP LP	$ 5,252	$ 9,967	$ (393)
Add (deduct):			
Operation and maintenance	130,826	131,629	58,000
General and administrative	57,863	51,323	39,713
(Gain) loss on assets sales	(133,284)	472	1,522
Management services termination fee	—	3,888	—
Transaction expenses	—	1,620	420
Depreciation and amortization	109,893	102,566	55,074
Income from unconsolidated subsidiary	(7,886)	—	—
Interest expense, net	77,996	63,243	52,016
Loss on debt refinancing	—	—	21,200
Other income and deductions, net	15,132	(332)	(1,252)
Income tax (benefit) expense	(1,095)	(266)	931
Net (income) loss attributable to noncontrolling interest	135,237	91,361	(13,138)
Total segment margin	$ 389,934	$ 455,471	$ 214,093

16. Equity-Based Compensation

Common Unit Option and Restricted (Non-Vested) Units. The Partnership's Long-Term Incentive Plan ("LTIP") for the Partnership's employees, directors and consultants covers an aggregate of 2,865,584 common units. Awards under the LTIP have been made since completion of the Partnership's IPO. All outstanding, unvested LTIP awards at the time of the GE EFS Acquisition vested upon the change of control. As a result, the Partnership recorded a one-time charge of $11,928,000 during the year ended December 31, 2007 that was recorded in general and administrative expenses. LTIP awards made subsequent to the GE EFS Acquisition generally vest on the basis of one-fourth of the award each year. Options expire ten years after the grant date. LTIP compensation expense of $5,590,000, $4,318,000, and $15,534,000, is recorded in general and administrative in the statement of operations for the years ended December 31, 2009, 2008, and 2007, respectively.

The fair value of each option award is estimated on the date of grant using the Black-Scholes Option Pricing Model. The Partnership used the simplified method outlined in Staff Accounting Bulletin No. 107 for estimating the exercise behavior of option grantees, given the absence of historical exercise data to provide a reasonable basis upon which to estimate expected term due to the limited period of time its units have been publicly traded. Upon the exercise of the common unit options, the Partnership intends to settle these obligations with new issues of common units on a net basis. The following assumptions apply to the options granted during the year ended December 31, 2007.

	For the Year Ended December 31, 2007
Weighted average expected life (years)	4
Weighted average expected dividend per unit	$ 1.51
Weighted average grant date fair value of options	$ 2.31
Weighted average risk free rate	4.60%
Weighted average expected volatility	16.0%
Weighted average expected forfeiture rate	11.0%

The common unit options activity for the years ended December 31, 2009, 2008, and 2007 is as follows.

Common Unit Options	2009 Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at the beginning of period	431,918	$ 21.31		
Granted	—	—		
Exercised	—	—		$ —
Forfeited or expired	(125,267)	20.87		
Outstanding at end of period	306,651	21.50	6.3	184
Exercisable at the end of the period	306,651			184

Common Unit Options	2008 Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at the beginning of period	738,668	$ 21.05		
Granted	—	—		
Exercised	(245,150)	20.55		$ 1,719
Forfeited or expired	(61,600)	21.11		
Outstanding at end of period	431,918	21.31	7.3	—
Exercisable at the end of the period	431,918			—

Common Unit Options	2007 Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value* (in thousands)
Outstanding at the beginning of period	909,600	$ 21.06		
Granted	21,500	27.18		
Exercised	(149,934)	21.78		$ 1,738
Forfeited or expired	(42,498)	21.85		
Outstanding at end of period	738,668	21.05	8.2	9,104
Exercisable at the end of the period	738,668			9,104

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented. Unit options with an exercise price greater than the end of the period closing market price are excluded.

The restricted (non-vested) common unit activity for the years ended December 31, 2009, 2008, and 2007 is as follows.

	2009	
Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	704,050	$ 29.26
Granted	24,500	11.13
Vested	(176,291)	29.78
Forfeited or expired	(88,250)	27.96
Outstanding at the end of period	464,009	28.36

	2008	
Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	397,500	$ 31.62
Granted	477,800	27.99
Vested	(90,500)	31.63
Forfeited or expired	(80,750)	30.66
Outstanding at the end of period	704,050	29.26

	2007	
Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	516,500	$ 21.06
Granted	615,500	30.44
Vested	(684,167)	22.91
Forfeited or expired	(50,333)	27.20
Outstanding at the end of period	397,500	31.62

The Partnership will make distributions to non-vested restricted common units at the same rate and on the same dates as the common units. Restricted common units are subject to contractual restrictions against transfer which lapse over time; non-vested restricted units are subject to forfeitures on termination of employment. As further disclosed in Note 17, due to the change in control of the General Partner, in May 2010, the Partnership recorded a one-time general and administrative charge of $9,893,000 as a result of the vesting of these LTIP units.

Phantom Units. During 2009, the Partnership awarded 308,200 phantom units to senior management and certain key employees. These phantom units are in substance two grants composed of (1) service condition grants (also defined as “time-based grants” in the LTIP plan document) with graded vesting occurring on March 15 of each of the following three years; and (2) market condition grants (also defined as “performance-based grants” in the LTIP plan document) with cliff vesting based upon the Partnership’s relative ranking in total unitholder return among 20 peer companies, which peer companies are disclosed in Item 11 of the Partnership’s Annual Report on Form 10-K for the year ended December 31, 2009. At the end of the measurement period (March 15, 2012) for the market condition grants, the phantom units will convert to common units in a ratio ranging from 0 to 150 percent. Upon a change in control, the market condition based grants will convert to common units at 150 percent and the service condition grants will convert to common on a one-for-one basis. For both the service condition grants and the market condition grants, distributions will be accumulated from the grant date and paid upon vesting at the same rate as the common units.

In determining the grant date fair value, the grant date closing price of the Partnership’s common units on NASDAQ was used for the service condition awards. For the market condition awards, a Monte Carlo simulation was performed which incorporated variables mainly including the unit price volatility and the grant-date closing price of the Partnership’s common units on NASDAQ.

During the year ended December 31, 2009, the Partnership recognized $418,000 of expense, which was reflected in general and administrative expense in the statement of operations. As further disclosed in Note 17, due to the change in control of the General Partner, all outstanding phantom units described below vested on May 26, 2010.

The following table presents phantom unit activity for the year ended December 31, 2009.

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	—	$ —
Service condition grants	133,480	13.43
Market condition grants	174,720	4.64
Vested service condition	—	—
Vested market condition	—	—
Forfeited service condition	(2,600)	12.46
Forfeited market condition	(3,900)	4.49
Total outstanding at end of period	301,700	8.63

17. Subsequent Events

Subsidiary distributions. On January 26, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit including units equivalent to the General Partner's two percent interest in the Partnership, and a distribution of approximately $728,000, with respect to incentive distribution rights, that was paid on February 12, 2010 to unitholders of record at the close of business on February 5, 2010.

On April 26, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit and Series A Preferred Unit, including units equivalent to the General Partner's two percent interest in the Partnership, and a distribution of approximately $713,000, with respect to incentive distribution rights, that was paid on May 14, 2010, to unitholders of record at the close of business on May 7, 2010.

On July 27, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit and Series A Preferred Unit, including units equivalent to the General Partner's two percent interest in the Partnership, and a distribution with respect to incentive distribution rights of approximately $915,000, payable on August 13, 2010, to unitholders of record at the close of business on August 6, 2010.

Escrow Payable. In connection with the El Paso PSA, $500,000 was released on May 6, 2010.

Keyes Litigation. On May 7, 2010, the jury rendered a verdict in favor of the Partnership. No damages were awarded to the Keyes. Keyes has appealed the verdict. The hearing on appeal will take place sometime in 2011.

Revolving Credit Facility. On March 4, 2010, RGS executed the Fifth Amended and Restated Credit Agreement (the "new credit agreement"), to be effective as of March 4, 2010. The material differences between the Fourth Amended and Restated Credit Agreement (the "previous credit agreement") and the new credit agreement include:

- The extension of the maturity date to June 15, 2014 from August 15, 2011, subject to the following contingency:
  - If the Partnership's 8.375 percent senior notes due December 15, 2013 have not been refinanced or paid off by June 15, 2013, then the maturity date of the revolving credit facility will be June 15, 2013;
- An increase in the amount of allowed investments in HPC to $250,000,000 from $135,000,000;
- The addition of an allowance for joint venture investments (other than HPC) of up to $75,000,000, provided that (i) distributed cash and net income from joint ventures under this basket shall be excluded from consolidated net income and (ii) equity interests in joint ventures created under this basket shall be pledged as collateral;
- The modification of financial covenants to give credit for projected EBITDA associated with certain future material HPC projects on a percentage of completion basis, provided that such amount, together with adjustments related to the Haynesville Expansion Project and other material projects, does not exceed 20 percent of consolidated EBITDA (as defined in the new credit agreement) through March 31, 2010, and 15 percent thereafter;
- An increase in the annual general asset sales permitted from $20,000,000 annually to five percent of consolidated net tangible assets (as defined in the new credit agreement) annually.

The new credit agreement and the guarantees are senior to the Partnership's and the guarantors' secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of March 31, 2010, the Partnership was in compliance with all of the financial covenants contained within the new credit agreement.

The Partnership treated the amendment of the credit facility as a modification of an existing revolving credit agreement and, therefore, recorded a write-off of debt issuance costs of $1,780,000 that was recorded to interest expense, net in the three months ended March 31, 2010. In addition, the Partnership paid and capitalized $15,272,000 loan fees which will be amortized over the remaining term of the credit facility.

On May 26, 2010, the Partnership amended its credit facility to, among other things:

- amend the definitions of "Consolidated EBITDA" and "Consolidated Net Income" in the Credit Agreement to include Midcontinent Express Pipeline, LLC ("MEP");
- amend the definition of "Joint Venture" in the Credit Agreement to include MEP;
- amend the definition of "Permitted Acquisition" in the Credit Agreement to clarify that the initial investment in MEP is a permitted acquisition under the terms of the Credit Agreement;
- amend the definition of "Permitted Holders" in the Credit Agreement to include Energy Transfer Equity, L.P. ("ETE") as a party that may hold the equity interests in the Managing General Partner (as defined below) without triggering an event of default under the Credit Agreement;
- amend Section 5.11(b) of the Credit Agreement to provide that the Partnership's equity interests in MEP will be pledged as collateral under the Credit Agreement (but only indirectly through the direct pledge of equity interests in Regency Midcontinent Express LLC ("Regency Midcon"), ETC Midcontinent Express Pipeline III L.L.C. ("ETC III") and, to the extent applicable, ETC Midcontinent Express Pipeline II L.L.C. ("ETC II");
- amend Section 6.04 of the Credit Agreement to permit certain investments in MEP by the Partnership and its affiliates;
- amend Section 6.09 of the Credit Agreement to include the investments in MEP and related agreements as permitted affiliate transactions; and
- amend Section 6.10(c) of the Credit Agreement to require that the Borrower and its subsidiaries maintain a senior secured leverage ratio not to exceed 3.00 to 1.00.

HPC Purchase. On April 30, 2010, the Partnership purchased 76,989 units representing general partner interests in HPC for an aggregate purchase price of $92,087,000 from EFS Haynesville, an affiliate of GECC and the Partnership. This purchase was funded using the Partnership's revolving credit facility and it increased the Partnership's ownership percentage in HPC from 43 percent to approximately 49.99 percent. The Partnership and EFS Haynesville also entered into a Voting Agreement which grants the Partnership the right to vote the general partner interest in HPC retained by EFS Haynesville. Because this transaction occurred between two entities that are under common control, partners' capital will be reduced by a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount during the second quarter of 2010.

Transfer of GP Interest. On May 26, 2010, Regency GP Acquirer, L.P. (the "GP Seller") completed the sale of all of the outstanding membership interests in Regency GP LLC (the "Managing General Partner") and all of the outstanding limited partners' interests in the General Partner pursuant to a Purchase Agreement (the "Purchase Agreement") among itself, ETE and ETE GP Acquirer LLC.

Prior to the closing of the transactions under the Purchase Agreement, GP Seller, an affiliate of GE EFS, owned all the outstanding limited partners' interests in the General Partner, which is the sole general partner of the Partnership, and the entire member's interest in the Managing General Partner, which is the sole general partner of the General Partner and by virtue of that position controlled the Partnership.

While none of the Partnership, Managing General Partner or General Partner was a party to the Purchase Agreement, the Partnership has been advised that:

- GP Seller received preferred units in ETE with a value of approximately $300,000,000;
- the approximately 24.7 million common units in the Partnership held by affiliates of GE EFS continue to be held by such affiliates and were not a part of this transaction; and
- the parties entered into an Investor Rights Agreement with respect to certain representation rights on the Board of Directors of the Managing General Partner, as described below.

As a result of this transaction, control of the Partnership has been transferred from GE EFS to ETE and the Partnership recorded a one time general and administrative charge of $9,893,000 as a result of the vesting of LTIP units in May 2010.

On May 26, 2010, the Partnership entered into the GP Seller Registration Rights Agreement. Under the GP Seller Registration Rights Agreement, the Partnership granted to the GP Seller certain registration rights, including rights to cause the Partnership to file with the SEC a shelf registration statement under the Securities Act with respect to resales of the Partnership common units owned by the GP Seller. The GP Seller Registration Rights Agreement also contains customary provisions regarding rights of indemnification between the parties with respect to certain applicable securities law liabilities.

MEP Purchase. On May 10, 2010, the Partnership, Regency Midcon and ETE entered into the Contribution Agreement, pursuant to which, following the closing of the transactions:

- ETE agreed to contribute to the Partnership (through Regency Midcon),
    - 100 percent of the membership interests in ETC III, and
    - an option to purchase all of the outstanding membership interests in ETC II, that is exercisable one year and one day following the closing; and
- the Partnership agreed to issue 26,266,791 of its common units to ETE valued at approximately $600,000,000 based on a 10-day volume weighted average closing price of the Partnership's common units as of May 4, 2010. The consideration payable under the Contribution Agreement is subject to a purchase price adjustment, payable in cash, based on changes in the working capital and long-term debt levels of MEP from those as of January 1, 2010 and any capital expenditures made by MEP after January 1, 2010.

ETC III and ETC II own a 49.9 percent and 0.1 percent membership interest in MEP, respectively.

The transactions contemplated by the Contribution Agreement were completed on May 26, 2010. At the closing of these transactions, (i) the Partnership issued 26,266,791 of its common units to ETE in a private placement, relying on Section 4(2) of the Securities Act of 1933, as amended (the "Securities Act"), and (ii) ETE paid $20,283,216 in cash to the Partnership as an estimated purchase price adjustment. The consideration is subject to further post-closing adjustment. Following completion of these transactions, the Partnership indirectly owns 49.9 percent of MEP and has an option to acquire an indirect .1 percent interest in MEP (as described above) that is exercisable on May 27, 2011. An affiliate of Kinder Morgan Energy Partners, L.P. continues to own the other 50 percent interest in MEP.

On May 26, 2010, the Partnership entered into the ETE Registration Rights Agreement with ETE. Under the ETE Registration Rights Agreement, the Partnership granted to ETE certain registration rights, including rights to cause the Partnership to file with the SEC a shelf registration statement under the Securities Act with respect to resales of the Partnership common units acquired by ETE under the Contribution Agreement. The ETE Registration Rights Agreement also contains customary provisions regarding rights of indemnification between the parties with respect to certain applicable securities law liabilities.

Immediately following the closing of the transactions contemplated by the Purchase Agreement and the Contribution Agreement described above, ETE beneficially owned 26,266,791 of the Partnership's common units (or approximately 21.99% of the Partnership's outstanding common units) and owned 100% of the interests in the Managing General Partner and the General Partner.

Services Agreement. On May 26, 2010, the Partnership entered into the Services Agreement with ETE and ETE Services Company, LLC ("Services Co."). Under the Services Agreement, Services Co. will perform certain general and administrative services to be agreed upon by the parties. The Partnership will pay Services Co.'s direct expenses for the provision of these services, plus an annual fee of $10,000,000, and the Partnership will receive the benefit of any cost savings recognized for these services. The Services Agreement has a five-year term, subject to earlier termination rights in the event of a change of control of a party, the failure to achieve certain costs savings for the benefit of the Partnership or upon an event of default.

Disposition. On July 15, 2010, the Partnership sold its gathering and processing assets located in east Texas to an affiliate of Tristream Energy LLC for approximately $70,000,000. The Partnership plans to use the proceeds from the sale of the assets to fund future capital expenditures.

Zephyr Acquisition. On September 1, 2010, the Partnership acquired Zephyr Gas Services, LLC, a field services company for approximately $185,000,000.

Equity Offering. On August 16, 2010, the Partnership issued 17,537,500 common units representing limited partner interests at $23.80 per common unit.

Management has evaluated subsequent events from the balance sheet date through September 13, 2010, the date the financial statements were available to be issued.

Exhibit 99.10

Regency GP LP

Consolidated Financial Statements
June 30, 2010

Regency GP LP
Condensed Consolidated Balance Sheets
(in thousands)

	Successor June 30, 2010 (unaudited)	Predecessor December 31, 2009
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 4,297	$ 9,828
Restricted cash	1,011	1,511
Trade accounts receivable, net of allowance of $475 and $1,130	22,801	30,433
Accrued revenues	76,272	95,240
Related party receivables	33,444	6,222
Derivative assets	19,833	24,987
Other current assets	8,420	10,556
Total current assets	166,078	178,777
Property, Plant and Equipment:		
Gathering and transmission systems	488,336	465,959
Compression equipment	785,685	823,060
Gas plants and buildings	131,537	159,596
Other property, plant and equipment	101,046	162,433
Construction-in-progress	125,528	95,547
Total property, plant and equipment	1,632,132	1,706,595
Less accumulated depreciation	(8,740)	(250,160)
Property, plant and equipment, net	1,623,392	1,456,435
Other Assets:		
Investment in unconsolidated subsidiaries	1,369,921	453,120
Long-term derivative assets	1,241	207
Other, net of accumulated amortization of debt issuance costs of $564 and $10,743	34,206	19,468
Total other assets	1,405,368	472,795
Intangible Assets and Goodwill:		
Intangible assets, net of accumulated amortization of $2,159 and $33,929	666,781	197,294
Goodwill	733,674	228,114
Total intangible assets and goodwill	1,400,455	425,408
TOTAL ASSETS	$ 4,595,293	$ 2,533,415
LIABILITIES & PARTNERS' CAPITAL AND NONCONTROLLING INTEREST		
Current Liabilities:		
Trade accounts payable	$ 43,513	$ 44,912
Accrued cost of gas and liquids	75,619	76,657
Related party payables	4,417	2,312
Deferred revenues, including related party amounts of $0 and $338	11,244	11,292
Derivative liabilities	3,576	12,256
Escrow payable	1,011	1,511
Other current liabilities, including related party amounts of $630 and $0	14,985	12,368
Total current liabilities	154,365	161,308
Long-term derivative liabilities	52,609	48,903
Other long-term liabilities	14,249	14,183
Long-term debt, net	1,276,640	1,014,299
Commitments and contingencies		
Series A convertible redeemable preferred units, redemption amount of $83,891 and $83,891	70,850	51,711
Partners' Capital and Noncontrolling Interest:		
Partners' interest	335,194	19,250
Accumulated other comprehensive loss	—	(1,994)
Noncontrolling interest	2,691,386	1,225,755
Total partners' capital and noncontrolling interest	3,026,580	1,243,011
TOTAL LIABILITIES AND PARTNERS' CAPITAL AND NONCONTROLLING INTEREST	$ 4,595,293	$ 2,533,415

See accompanying notes to condensed consolidated financial statements

Regency GP LP
Condensed Consolidated Statements of Operations
Unaudited
(in thousands)

	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010	Three Months Ended June 30, 2009
REVENUES			
Gas sales, including related party amounts of $447, $0, and $0	$ 48,103	$ 89,170	$ 106,897
NGL sales including related party amounts of $18,054, $0, and $0	28,766	69,033	57,676
Gathering, transportation and other fees, including related party amounts of $2,086, $3,680, and $2,239	22,884	45,733	69,231
Net realized and unrealized (loss) gain from derivatives	(130)	223	12,515
Other	3,357	7,336	7,223
Total revenues	102,980	211,495	253,542
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $2,281, $3,198, and $1,453	74,081	147,262	157,347
Operation and maintenance	11,942	21,430	31,974
General and administrative, including related party amounts of $833, $0, and $0	7,104	21,809	14,127
Loss on asset sales, net	10	19	651
Depreciation and amortization	10,995	18,609	26,236
Total operating costs and expenses	104,132	209,129	230,335
OPERATING (LOSS) INCOME	(1,152)	2,366	23,207
Income from unconsolidated subsidiaries	8,121	7,959	1,587
Interest expense, net	(8,109)	(14,114)	(19,568)
Other income and deductions, net	(3,510)	(624)	214
(LOSS) INCOME BEFORE INCOME TAXES	(4,650)	(4,413)	5,440
Income tax expense (benefit)	245	83	(515)
NET (LOSS) INCOME	$ (4,895)	$ (4,496)	$ 5,955
Net loss (income) attributable to noncontrolling interest	5,698	4,496	(5,214)
NET INCOME ATTRIBUTABLE TO REGENCY GP LP	$ 803	$ —	$ 741

See accompanying notes to condensed consolidated financial statements

Regency GP LP
Condensed Consolidated Statements of Operations
Unaudited
(in thousands)

	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
REVENUES			
Gas sales, including related party amounts of $447, $0, and $0	$ 48,103	$ 232,063	$ 254,793
NGL sales including related party amounts of $18,054, $0, and $0	28,766	166,362	107,261
Gathering, transportation and other fees, including related party amounts of $2,086, $12,200 and $3,376	22,884	116,061	142,079
Net realized and unrealized (loss) gain from derivatives	(130)	(716)	26,970
Other	3,357	15,477	12,417
Total revenues	102,980	529,247	543,520
OPERATING COSTS AND EXPENSES			
Cost of sales, including related party amounts of $2,281, $6,564 and $1,700	74,081	371,871	339,875
Operation and maintenance	11,942	53,841	68,016
General and administrative, including related party amounts of $833, $0, and $0	7,104	37,212	29,205
Loss (gain) on asset sales, net	10	303	(133,280)
Depreciation and amortization	10,995	46,084	54,125
Total operating costs and expenses	104,132	509,311	357,941
OPERATING (LOSS) INCOME	(1,152)	19,936	185,579
Income from unconsolidated subsidiaries	8,121	15,872	1,923
Interest expense, net	(8,109)	(36,459)	(33,795)
Other income and deductions, net	(3,510)	(3,891)	256
(LOSS) INCOME BEFORE INCOME TAXES	(4,650)	(4,542)	153,963
Income tax expense (benefit)	245	404	(416)
NET (LOSS) INCOME	$ (4,895)	$ (4,946)	$ 154,379
Net loss (income) attributable to noncontrolling interest	5,698	5,608	(150,105)
NET INCOME ATTRIBUTABLE TO REGENCY GP LP	$ 803	$ 662	$ 4,274

See accompanying notes to condensed consolidated financial statements

Regency GP LP
Condensed Consolidated Statements of Comprehensive (Loss) Income
Unaudited
(in thousands)

	Three Months Ended June 30, 2010 and 2009		
	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to May 25, 2010	Three Months Ended June 30, 2009
Net (loss) income	$ (4,895)	$ (4,496)	$ 5,955
Net hedging amounts reclassified to earnings	—	(512)	(13,644)
Net change in fair value of cash flow hedges	—	8,649	(14,622)
Comprehensive (loss) income	$ (4,895)	$ 3,641	$ (22,311)
Comprehensive (loss) income attributable to noncontrolling interest	(5,698)	12,470	(32,915)
Comprehensive income (loss) attributable to Regency GP LP	$ 803	$ (8,829)	$ 10,604

	Six Months Ended June 30, 2010 and 2009		
	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
Net (loss) income	$ (4,895)	$ (4,946)	$ 154,379
Net hedging amounts reclassified to earnings	—	2,145	(27,894)
Net change in fair value of cash flow hedges	—	18,486	(9,242)
Comprehensive (loss) income	$ (4,895)	$ 15,685	$ 117,243
Comprehensive (loss) income attributable to noncontrolling interest	(5,698)	14,610	113,712
Comprehensive income attributable to Regency GP LP	$ 803	$ 1,075	$ 3,531

See accompanying notes to condensed consolidated financial statements

Regency GP LP
Condensed Consolidated Statements of Cash Flows
Unaudited
(in thousands)

	Successor	Predecessor	
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
OPERATING ACTIVITIES			
Net (loss) income	$ (4,895)	$ (4,946)	$ 154,379
Adjustments to reconcile net (loss) income to net cash flows provided by (used in) operating activities:			
Depreciation and amortization, including debt issuance cost amortization	11,330	49,363	56,750
Write-off of debt issuance costs	—	1,780	—
Income from unconsolidated subsidiaries	(8,121)	(15,872)	(1,923)
Derivative valuation changes	6,921	12,004	(6,293)
Loss (gain) on asset sales, net	10	303	(133,280)
Subsidiary unit-based compensation expenses	137	12,070	2,750
Cash flow changes in current assets and liabilities:			
Trade accounts receivable, accrued revenues, and related party receivables	13,843	(11,272)	38,073
Other current assets	585	2,516	3,728
Trade accounts payable, accrued cost of gas and liquids, related party payables and deferred revenues	(15,460)	8,649	(39,185)
Other current liabilities	(20,497)	22,614	(7,396)
Distributions received from unconsolidated subsidiaries	—	12,446	1,900
Other assets and liabilities	(60)	(234)	(232)
Net cash flows (used in) provided by operating activities	(16,207)	89,421	69,271
INVESTING ACTIVITIES			
Capital expenditures	(20,875)	(63,787)	(119,185)
Capital contribution to unconsolidated subsidiaries	(38,922)	(20,210)	—
Acquisitions, net of cash received	12,848	(75,114)	—
Proceeds from asset sales	14	10,661	83,182
Net cash flows (used in) investing activities	(46,935)	(148,450)	(36,003)
FINANCING ACTIVITIES			
Net borrowings (repayments) under revolving credit facility	37,000	199,008	(177,249)
Proceeds from issuance of senior notes, net of discount	—	—	236,240
Debt issuance costs	(132)	(15,728)	(11,939)
Partner contributions	7,436	—	—
Distributions to partners	—	(1,574)	(2,620)
Distributions to noncontrolling interests	—	—	—
Acquisition of assets between entities under common control in excess of historical cost	—	(16,973)	—
Subsidiary distributions to noncontrolling interest	—	(85,639)	(69,024)
Proceeds from subsidiary option exercises	150	120	—
Subsidiary equity issuance costs	—	(89)	—
Distributions to redeemable convertible subsidiary preferred units	—	(1,945)	—
Tax withholding on subsidiary unit-based vesting	—	(4,994)	—
Net cash flows provided by (used in) financing activities	44,454	72,186	(24,592)
Net change in cash and cash equivalents	(18,688)	13,157	8,676
Cash and cash equivalents at beginning of period	22,985	9,828	600
Cash and cash equivalents at end of period	$ 4,297	$ 22,985	$ 9,276
Supplemental cash flow information:			
Non-cash capital expenditures	$ 16,159	$ 18,051	$ 9,480
Issuance of subsidiary common units for an acquisition	584,436	—	—
Deemed contribution from acquisition of assets between entities under common control	17,152	—	—
Release of escrow payable from restricted cash	—	500	—
Contribution of fixed assets, goodwill and working capital to HPC	—	—	263,921
Partner contribution receivable	12,288	—	—

See accompanying notes to condensed consolidated financial statements

Regency GP LP
Condensed Consolidated Statements of Partners' Capital and Noncontrolling Interest
Unaudited
(in thousands)

	Partners' Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Predecessor				
Balance—December 31, 2009	$ 19,250	$ (1,994)	$ 1,225,755	$1,243,011
Subsidiary issuance of common units under LTIP, net of forfeitures and tax withholding			(4,994)	(4,994)
Subsidiary issuance of common units, net of costs	—	—	(89)	(89)
Subsidiary exercise of common unit options	—	—	120	120
Subsidiary unit-based compensation expenses	—	—	12,070	12,070
Accrued distributions to subsidiary phantom units	—	—	(473)	(473)
Acquisition of assets between entities under common control in excess of historical cost	(16,973)	—	—	(16,973)
Distributions to partners	(1,574)	—	—	(1,574)
Subsidiary distributions	—	—	(85,639)	(85,639)
Net (loss) income	662	—	(5,608)	(4,946)
Distributions of Series A convertible redeemable subsidiary preferred units	(39)	—	(1,906)	(1,945)
Accretion of Series A convertible redeemable subsidiary preferred units	—	—	(55)	(55)
Net cash flow hedge amounts reclassified to earnings	—	2,145	—	2,145
Net change in fair value of cash flow hedges	—	18,486	—	18,486
Balance—May 25, 2010	$ 1,326	$ 18,637	$ 1,139,181	$1,159,144

	Partners' Interest	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Successor				
Balance—May 26, 2010	$304,951	$ —	$ 2,104,982	$2,409,933
Subsidiary issuance of common units, net of costs	—	—	584,436	584,436
Subsidiary exercise of common unit options	—	—	150	150
Subsidiary unit-based compensation expenses	—	—	137	137
Acquisition of assets between entities under common control below historical cost	17,152	—	—	17,152
Partner contributions	12,288	—	7,436	19,724
Net (loss) income	803	—	(5,698)	(4,895)
Accretion of Series A convertible redeemable subsidiary preferred units	—	—	(57)	(57)
Balance—June 30, 2010	$335,194	$ —	$ 2,691,386	$3,026,580

See accompanying notes to condensed consolidated financial statements

Regency GP LP
Notes to Condensed Consolidated Financial Statements
(Unaudited as of June 30, 2010 and June 30, 2009)

1. Organization and Summary of Significant Accounting Policies

Organization of Regency GP LP. Regency GP LP (the "General Partner") is the general partner of Regency Energy Partners LP. The General Partner owns a 2 percent general partner interest and incentive distribution rights in Regency Energy Partners LP. The General Partner's general partner is Regency GP LLC.

Organization of Regency Energy Partners LP. Regency Energy Partners LP and its subsidiaries (the "Partnership") are engaged in the business of gathering, processing and transporting natural gas and natural gas liquids ("NGLs") as well as providing contract compression services.

Basis of presentation. The General Partner has no independent operations and no material assets outside those of the Partnership. The number of reconciling items between the consolidated balance sheet and that of the Partnership are few. The most significant difference is that relating to noncontrolling interest ownership in the General Partner's net assets by certain limited partners of the Partnership, and the elimination of General Partner's investment in the Partnership.

On May 26, 2010, Regency GP LLC ("GP Seller") completed the sale of all of the outstanding membership interests of the General Partner pursuant to a Purchase Agreement (the "Purchase Agreement") among itself, Energy Transfer Equity, L.P. ("ETE") and ETE GP Acquirer LLC ("ETE GP") (the "ETE Acquisition"). Prior to the closing of the Purchase Agreement, GP Seller, an affiliate of General Electric Energy Financial Services ("GE EFS"), owned all the outstanding limited partners' interests in the General Partner, which is the sole general partner of the Partnership, and the entire member's interest in the Managing General Partner, which is the sole general partner of the General Partner and, by virtue of that position, controlled the Partnership. Control of the Partnership transferred from GE EFS to ETE as a result of the ETE Acquisition. In connection with this transaction, the General Partner and Partnership's assets and liabilities were required to be adjusted to fair value on the closing date (May 26, 2010) by application of "push-down" accounting (the "Push-down Adjustments"). Total enterprise value of the General Partner and Partnership as of May 26, 2010 was $3,783,681,000, giving effect to the transaction and the associated Push-down Adjustments, which is calculated below:

	(in thousands)
Fair value of limited partners interest, based on the number of outstanding Partnership common units and the trading price on May 26, 2010	$ 2,073,532
Fair value of consideration paid for general partner interest	304,951
Noncontrolling interest	31,450
Series A convertible redeemable preferred units	70,793
Fair value of long-term debt	1,239,863
Other long-term liabilities	63,092
Enterprise value	$ 3,783,681

The General Partner has developed the preliminary amount of the fair value of the Partnership's assets and liabilities. Management is reviewing the valuation and confirming results to determine the final purchase price allocation. The General Partner allocated the enterprise value to the following assets and liabilities of the Partnership based on their respective estimated fair values as of May 26, 2010:

	At May 26, 2010 (in thousands)
Working capital	$ (3,285)
Gathering and transmission systems	487,792
Compression equipment	779,634
Gas plants and buildings	131,537
Other property, plant and equipment	100,267
Construction-in-progress	114,146
Other long-term assets	36,839
Investment in unconsolidated subsidiary	734,137
Intangible assets	668,940
Goodwill	733,674
	$ 3,783,681

Due to the Push-down Adjustments, the General Partner's unaudited condensed consolidated financial statements and certain footnote disclosures are presented in two distinct periods to indicate the application of two different bases of accounting between the periods presented: (1) the period prior to the acquisition date (May 26, 2010), identified as "Predecessor" and (2) the period from May 26, 2010 forward, identified as "Successor".

The unaudited financial information as of, and for the three and six months ended June 30, 2010, has been prepared on the same basis as the audited consolidated financial statements included in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009. In the opinion of the Partnership's management, such financial information reflects all adjustments necessary for a fair presentation of the financial position and the results of operations for such interim periods in accordance with accounting principles generally accepted in the United States ("GAAP"). All inter-company items and transactions have been eliminated in consolidation. Certain information and footnote disclosures normally included in annual consolidated financial statements prepared in accordance with GAAP have been omitted pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC").

Use of Estimates. The unaudited condensed consolidated financial statements have been prepared in conformity with GAAP and, of necessity, include the use of estimates and assumptions by management. Actual results could differ from these estimates.

Intangible Assets. Intangible assets, net consist of the following.

	Contracts	Customer Relations	Trade Names (in thousands)	Permits and Licenses	Total
Predecessor					
Balance at December 31, 2009	$126,332	$35,362	$ 30,508	$ 5,092	$197,294
Amortization	(3,322)	(817)	(975)	(214)	(5,328)
Balance at May 25, 2010	$123,010	$34,545	$ 29,533	$ 4,878	$191,966

	Customer Relations	Trade Names (in thousands)	Total
Successor			
Balance at May 26, 2010	$604,840	$64,100	$668,940
Amortization	(1,905)	(254)	(2,159)
Balance at June 30, 2010	$602,935	$63,846	$666,781

The expected amortization of the intangible assets for each of the five succeeding years is as follows.

Year ending December 31,	Total (in thousands)
2010 (remaining)	$ 11,606
2011	23,211
2012	23,211
2013	23,211
2014	23,211

Recently Issued Accounting Standards. In June 2009, the Financial Accounting Standards Board ("FASB") issued guidance that significantly changed the consolidation model for variable interest entities. The guidance is effective for annual reporting periods that begin after November 15, 2009, and for interim periods within that first annual reporting period. The Partnership determined that this guidance had no impact on its financial position, results of operations or cash flows upon adoption on January 1, 2010.

In January 2010, the FASB issued guidance requiring improved disclosure of transfers in and out of Levels 1 and 2 for an entity's fair value measurements, such requirement becoming effective for interim and annual periods beginning after December 15, 2009. Further, additional disclosure of activities such as purchases, sales, issuances and settlements of items relying on Level 3 inputs will be required, such requirements becoming effective for interim and annual periods beginning after December 15, 2010. The Partnership determined that this guidance with respect to Levels 1, 2 and 3 had no impact on its financial position, results of operations or cash flows upon adoption.

In February 2010, the FASB clarified the type of embedded credit derivative that is exempt from embedded derivative bifurcation requirements. The Partnership determined that this guidance had no impact on its financial position, results of operations or cash flows.

2. Acquisitions

On April 30, 2010, the Partnership purchased an additional 6.99 percent general partner interest in RIGS Haynesville Partnership Co. ("HPC") from EFS Haynesville LLC ("EFS Haynesville"), bringing its total general partner interest in HPC to 49.99 percent. The purchase price of $92,087,000 was funded by borrowings under the Partnership's revolving credit facility. Because this transaction occurred between two entities under common control, partners' capital was decreased by $16,973,000, which represented a deemed distribution of the excess purchase price over EFS Haynesville's carrying amount of $75,114,000.

On May 26, 2010, the Partnership purchased a 49.9 percent interest in Midcontinent Express Pipeline LLC ("MEP") from ETE. The Partnership issued 26,266,791 common units to ETE, valued at $584,436,000, and received a working capital adjustment of $12,848,000 from ETE that was recorded as an adjustment to investment in unconsolidated subsidiaries. Because this transaction occurred between two entities under common control, partners' capital was increased by $17,152,000, which represented a deemed contribution of the excess carrying amount of ETE's investment of $588,740,000 over the purchase price. MEP is a 500 mile natural gas pipeline system that extends from the southeast corner of Oklahoma, across northeast Texas, northern Louisiana, central Mississippi and into Alabama. In June 2010, the Partnership made an additional capital contribution of $38,922,000 to MEP.

The following unaudited pro forma financial information has been prepared as if the transactions involving the purchase of 6.99 percent general partner interest in HPC, purchase of the 49.9 percent interest in MEP, together with the Push-down Adjustments described in Note 1 occurred as of the beginning of the earliest period presented. Such unaudited pro forma financial information does not purport to be indicative of the results of operations that would have been achieved if the transactions to which the Partnership is giving pro forma effect actually occurred on the dates referred to above or the results of operations that may be expected in the future.

	Pro Forma Results for the			
	Period from April 1, 2010 to May 25, 2010	Three Months Ended June 30, 2009	Period from January 1, 2010 to May 25, 2010	Six Months Ended June 30, 2009
	(in thousands except unit and per unit data)			
Total revenues	$ 211,495	$ 253,542	$ 529,247	$ 531,547
Net (loss) income	$ (4,117)	$ (2,516)	$ (5,702)	$ 134,011
Less: Amounts allocated to noncontrolling interests	$ 4,918	$ 3,289	$ 7,343	$ 129,741
Net income attributable to Regency GP LP	$ 801	$ 773	$ 1,641	$ 4,270

3. Investment in Unconsolidated Subsidiaries

HPC was established in March 2009 and as of June 30, 2010, the Partnership owns a 49.99 percent partner's interest in HPC. Following table summarizes the changes in the Partnership's investment in HPC.

	Successor	Predecessor			
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to Disposition (May 25, 2010)	Three Months Ended June 30, 2009	Period from January 1, 2010 to Disposition (May 25, 2010)	Six Months Ended June 30, 2009
	(in thousands)	(in thousands)			
Contributions to HPC	$ —	$ 20,210	$ —	$ 20,210	$ 400,000
Distributions received from HPC	—	8,920	1,900	12,446	1,900
Partnership's share of HPC's net income	4,460	7,959	1,587	15,872	1,923

As discussed in Note 1, the Partnership's investment in HPC was adjusted to its fair value on May 26, 2010 and the excess fair value over net book value was comprised of two components: (1) $143,757,000 was attributed to HPC's long-lived assets and is being amortized as a reduction of income from unconsolidated subsidiaries over the useful lives of the respective assets, which vary from 15 to 30 years, and (2) $38,510,000 could not be attributed to a specific asset and therefore will not be amortized in future periods. For the period from May 26, 2010 to June 30, 2010, the Partnership recorded $365,000 as a reduction of income from unconsolidated subsidiaries due to the amortization of the excess fair value of long-lived assets.

The summarized financial information of HPC is disclosed below.

RIGS Haynesville Partnership Co.
Condensed Consolidated Balance Sheets
(in thousands)

	June 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
Total current assets	$ 48,383	$ 39,239
Restricted cash, non-current	43,314	33,595
Property, plant and equipment, net	888,542	861,570
Total other assets	149,065	149,755
TOTAL ASSETS	$1,129,304	$ 1,084,159
LIABILITIES & PARTNERS' CAPITAL		
Total current liabilities	$ 17,273	$ 30,967
Partners' capital	1,112,031	1,053,192
TOTAL LIABILITIES & PARTNERS' CAPITAL	$1,129,304	$ 1,084,159

RIGS Haynesville Partnership Co.
Condensed Consolidated Income Statements
(in thousands)

	For the Three Months Ended June 30,		For the Six Months Ended June 30, 2010	From Inception (March 18, 2009) to June 30, 2009
	2010	2009		
	(Unaudited)		(Unaudited)	
Total revenues	$44,375	$11,707	$ 79,564	$ 13,533
Total operating costs and expenses	18,425	8,038	35,148	9,084
OPERATING INCOME	25,950	3,669	44,416	4,449
Interest expense	(99)	—	(201)	—
Other income and deductions, net	20	509	59	613
NET INCOME	$25,871	$ 4,178	$ 44,274	$ 5,062

Investment in MEP. On May 26, 2010, the Partnership purchased a 49.9 interest in the MEP from ETE. In June 2010, the Partnership made an additional capital contribution of $38,922,000 to MEP. During the period from May 26, 2010 to June 30, 2010, the Partnership recognized $4,026,000 in income from unconsolidated subsidiaries for its ownership interest.

The summarized financial information of MEP is disclosed below.

Midcontinent Express Pipeline LLC
Condensed Balance Sheet
(in thousands)

	June 30, 2010 (Unaudited)
ASSETS	
Total current assets	$ 32,987
Property, plant and equipment, net	2,225,383
Total other assets	5,588
TOTAL ASSETS	$2,263,958
LIABILITIES & PARTNERS' CAPITAL	
Total current liabilities	$ 92,795
Long-term debt	800,000
Partners' capital	1,371,163
TOTAL LIABILITIES & PARTNERS' CAPITAL	$2,263,958

Midcontinent Express Pipeline LLC
Condensed Income Statement
(in thousands)

	Month Ended June 30, 2010 (Unaudited)
Total revenues	$ 21,269
Total operating costs and expenses	9,770
OPERATING INCOME	11,499
Interest expense, net	(3,431)
NET INCOME	$ 8,068

4. Derivative Instruments

Policies. The Partnership has established comprehensive risk management policies and procedures to monitor and manage the market risks associated with commodity prices, counterparty credit, and interest rates. The General Partner is responsible for delegation of transaction authority levels, and the Risk Management Committee of the General Partner is responsible for the overall management of these risks, including monitoring exposure limits. The Risk Management Committee receives regular briefings on exposures and overall risk management in the context of market activities.

Commodity Price Risk. The Partnership is a net seller of NGLs, condensate and natural gas as a result of its gathering and processing operation. The prices of these commodities are impacted by changes in the supply and demand as well as market focus. Both the Partnership's profitability and cash flow are affected by the inherent volatility of these commodities which could adversely affect its ability to make distributions to its unitholders. The Partnership manages this commodity price exposure through an integrated strategy that includes management of its contract portfolio, matching sales prices of commodities with purchases, optimization of its portfolio by monitoring basis and other price differentials in operating areas, and the use of derivative contracts. In some cases, the Partnership may not be able to match pricing terms or to cover its risk to price exposure with financial hedges, and it may be exposed to commodity price risk. It is the Partnership's policy not to take any speculative positions with its derivative contracts.

On May 26, 2010, all of the Partnership's outstanding commodity swaps that were previously accounted for as cash flow hedges were de-designated and are currently accounted for under the mark-to-market method of accounting.

The Partnership executes natural gas, NGLs' and West Texas Intermediate Crude ("WTI") trades on a periodic basis to hedge its anticipated equity exposure. Subsequent to June 30, 2010, the Partnership has executed additional NGL swaps to hedge its 2011 and 2012 price exposure.

The Partnership has executed swap contracts settled against NGLs (ethane, propane, butane and natural gasoline), condensate and natural gas market prices for expected equity exposure in the approximate percentages set forth.

	As of June 30, 2010			As of August 8, 2010		
	2010	2011	2012	2010	2011	2012
NGLs	87%	52%	0%	87%	67%	6%
Condensate	96%	74%	7%	96%	74%	7%
Natural gas	74%	42%	0%	74%	42%	0%

Interest Rate Risk. The Partnership is exposed to variable interest rate risk as a result of borrowings under its revolving credit facility. As of June 30, 2010, the Partnership had $655,650,000 of outstanding borrowings exposed to variable interest rate risk. The Partnership's $300,000,000 interest rate swaps expired in March 2010. In April 2010, the Partnership entered into additional two-year interest rate swaps related to $250,000,000 of borrowings under its revolving credit facility, effectively locking the base rate, exclusive of the applicable margin, for these borrowings at 1.325 percent through April 2012.

Credit Risk. The Partnership's resale of natural gas exposes it to credit risk, as the margin on any sale is generally a very small percentage of the total sales price. Therefore, a credit loss can be very large relative to overall profitability on these transactions. The Partnership attempts to ensure that it issues credit only to credit-worthy counterparties and that in appropriate circumstances extension of credit is backed by adequate collateral such as a letter of credit or parental guarantee.

The Partnership is exposed to credit risk from its derivative counterparties. The Partnership does not require collateral from these counterparties. The Partnership deals primarily with financial institutions when entering into financial derivatives. The Partnership has entered into Master International Swap Dealers Association ("ISDA") Agreements that allow for netting of swap contract receivables and payables in the event of default by either party. If the Partnership's counterparties fail to perform under existing swap contracts, the Partnership's maximum loss would be $21,346,000, which would be reduced by $2,824,000 due to the netting feature. The Partnership has elected to present assets and liabilities under Master ISDA Agreements gross on the condensed consolidated balance sheets.

Embedded Derivatives. The Series A Preferred Units contain embedded derivatives which are required to be bifurcated and accounted for separately, such as the holders' conversion option and the Partnership's call option. These embedded derivatives are accounted for using mark-to-market accounting. The Partnership does not expect the embedded derivatives to affect its cash flows.

The Partnership's derivative assets and liabilities, including credit risk adjustment, as of June 30, 2010 and December 31, 2009 are detailed below.

	Assets		Liabilities	
	June 30, 2010 (unaudited)	December 31, 2009	June 30, 2010 (unaudited)	December 31, 2009
		(in thousands)		
Derivatives designated as cash flow hedges				
Current amounts				
Interest rate contracts	$ —	$ —	$ —	$ 1,064
Commodity contracts	—	9,521	—	11,161
Long-term amounts				
Commodity contracts	—	207	—	931
Total cash flow hedging instruments	—	9,728	—	13,156
Derivatives not designated as cash flow hedges				
Current amounts				
Commodity contracts	19,833	15,466	2,052	31
Interest rate contracts	—	—	1,524	—
Long-term amounts				
Commodity contracts	1,241	—	15	3,378
Interest rate contracts	—	—	355	
Embedded derivatives in Series A Preferred Units	—	—	52,239	44,594
Total derivatives not designated as cash flow hedges	21,074	15,466	56,185	48,003
Total derivatives	$ 21,074	$ 25,194	$ 56,185	$ 61,159

The following tables detail the effect of the Partnership's derivative assets and liabilities in the consolidated statement of operations for the period presented.

For the Three Months Ended June 30, 2010 and 2009

		Successor	Predecessor	
		Period from May 26, 2010 through June 30, 2010	**Period from April 1, 2010 through May 25, 2010**	**For the Three Months Ended June 30, 2009**
		(in thousands)	**(in thousands)**	
			Change in Value Recognized in OCI on Derivatives (Effective Portion)	
Derivatives in cash flow hedging relationships:				
Commodity derivatives		—	7,428	(13,946)
Interest rate swap derivatives		—	—	(676)
		—	7,428	(14,622)
			Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)	
	Location of Gain (Loss) Recognized in Income			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(709)	15,546
Interest rate swap derivatives	Interest expense	—	—	(1,515)
		—	(709)	14,031
			Amount of Gain/(Loss) Recognized in Income on Ineffective Portion	
	Location of Gain (Loss) Recognized in Income			
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(301)	1,616
Interest rate swap derivatives	Interest expense	—	—	—
		—	(301)	1,616
			Amount of Gain/(Loss) from Dedesignation Amortized from AOCI into Income	
	Location of Gain (Loss) Recognized in Income			
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	—	1,221	(387)
Interest rate swap derivatives	Interest expense	—	—	—
		—	1,221	(387)
			Amount of Gain/(Loss) Recognized in Income on Derivatives	
	Location of Gain (Loss) Recognized in Income			
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	(824)	12	(5,690)
Interest rate swap derivatives	Interest expense	(1,715)	(824)	—
Embedded derivative	Other income & deductions	(3,606)	(654)	—
		(6,145)	(1,466)	(5,690)

For the Six Months Ended June 30, 2010 and 2009

	Location of Gain (Loss) Recognized in Income	Successor	Predecessor	
		Period from May 26, 2010 through June 30, 2010	Period from January 1, 2010 through May 25, 2010	For the Six Months Ended June 30, 2009
		(in thousands)	(in thousands)	
Change in Value Recognized in OCI on Derivatives (Effective Portion)				
Derivatives in cash flow hedging relationships:				
Commodity derivatives		—	14,371	(7,728)
Interest rate swap derivatives		—	—	(1,514)
		—	14,371	(9,242)
Amount of Gain/(Loss) Reclassified from AOCI into Income (Effective Portion)				
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(5,200)	32,065
Interest rate swap derivatives	Interest expense	—	(1,060)	(2,987)
		—	(6,260)	29,078
Amount of Gain/(Loss) Recognized in Income on Ineffective Portion				
Derivatives in cash flow hedging relationships:				
Commodity derivatives	Revenues	—	(799)	2,231
Interest rate swap derivatives	Interest expense	—	—	—
		—	(799)	2,231
Amount of Gain/(Loss) from Dedesignation Amortized from AOCI into Income				
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	—	4,115	(1,184)
Interest rate swap derivatives	Interest expense	—	—	—
		—	4,115	(1,184)
Amount of Gain/(Loss) Recognized in Income on Derivatives				
Derivatives not designated in a hedging relationship:				
Commodity derivatives	Revenues	(824)	1,247	(7,092)
Interest rate swap derivatives	Interest expense	(1,715)	(824)	—
Embedded derivative	Other income & deductions	(3,606)	(4,039)	—
		(6,145)	(3,616)	(7,092)

5. Long-term Debt

Obligations in the form of senior notes and borrowings under the credit facility are as follows.

	June 30, 2010	December 31, 2009
	(in thousands)	
Senior notes	$ 620,990	$ 594,657
Revolving loans	655,650	419,642
Total	1,276,640	1,014,299
Less: current portion	—	—
Long-term debt	$1,276,640	$1,014,299
Availability under revolving credit facility:		
Total credit facility limit	$ 900,000	$ 900,000
Unfunded commitments	—	(10,675)
Revolving loans	(655,650)	(419,642)
Letters of credit	(17,032)	(16,257)
Total available	$ 227,318	$ 453,426

Long-term debt maturities as of June 30, 2010 for each of the next five years are as follows:

	Amount (in thousands)
Year Ending December 31,	
2010	$ —
2011	—
2012	—
2013	357,500
2014	655,650
Thereafter	250,000
Total	$ 1,263,150

The outstanding balance of revolving debt under the revolving credit facility bears interest at LIBOR plus a margin or Alternate Base Rate (equivalent to the U.S prime rate lending rate) plus a margin or a combination of both. The senior notes pay fixed interest rates and the weighted average coupon rate is 8.787 percent. The weighted average interest rates for the revolving loans and senior notes, including interest rate swap settlements, commitment fees, and amortization of debt issuance costs were 5.74 percent during the period from May 26, 2010 to June 30, 2010, 7.98 percent during the period from April 1, 2010 to May 25, 2010, 6.69 percent during the three months ended June 30, 2009, 7.98 percent during the period from January 1, 2010 to May 25, 2010 and 5.94 percent during the six months ended June 30, 2009.

Senior Notes. The senior notes are jointly and severally guaranteed by all of the Partnership's current consolidated subsidiaries, other than Regency Energy Finance Corp. ("Finance Corp."), a wholly owned subsidiary of the Partnership, and by certain of its future subsidiaries. The senior notes and the guarantees are unsecured and rank equally with all of the Partnership's and the guarantors' existing and future unsubordinated obligations. The senior notes and the guarantees will be senior in right of payment to any of the Partnership's and the guarantors' future obligations that are, by their terms, expressly subordinated in right of payment to the notes and the guarantees. The senior notes and the guarantees will be effectively subordinated to the Partnership's and the guarantors' secured obligations, including the Partnership's credit facility and the Series A Convertible Redeemable Preferred Units ("Series A Preferred Units"), to the extent of the value of the assets securing such obligations. As of June 30, 2010, the Partnership was in compliance with each of the financial covenants required under the terms of the senior notes.

Finance Corp. has no operations and will not have revenues other than as may be incidental as co-issuer of the senior notes. Since the Partnership has no independent operations, the guarantees are fully unconditional and joint and several of its subsidiaries, except certain wholly owned subsidiaries, the Partnership has not included condensed consolidated financial information of guarantors of the senior notes.

Upon a change in control, each holder of the Partnership's senior notes may, at its option, require the Partnership to purchase all or a portion of its notes at a purchase price of 101 percent plus accrued interest and liquidated damages, if any. Subsequent to the ETE Acquisition, no noteholder has exercised this option.

As disclosed in Note 1, the Partnership's long-term debt was adjusted to their fair value on May 26, 2010. The fair value of the senior notes was adjusted based on quoted market prices. The re-measurement of the senior notes due 2013 and 2016 resulted in premium of $7,150,000 and $6,563,000, respectively.

The unamortized premium or discount on the Partnership's senior notes as of June 30, 2010 and December 31, 2009 are as follows.

	Successor	Predecessor
	June 30, 2010	December 31, 2009
	(in thousands)	(in thousands)
Senior Notes Due 2013		
Principal amount	$ 357,500	$ 357,500
add:		
Unamortized Premium	6,998	—
Carrying value	$ 364,498	$ 357,500
Senior Notes Due 2016		
Principal amount	$ 250,000	$ 250,000
add/ deduct:		
Unamortized Premium (Discount)	6,492	(12,843)
Carrying value	$ 256,492	$ 237,157

Revolving Credit Facility. On March 4, 2010, Regency Gas Services LP ("RGS"), a wholly owned subsidiary of the Partnership, executed the Fifth Amended and Restated Credit Agreement (the "new credit agreement"), to be effective as of March 4, 2010. The material differences between the Fourth Amended and Restated Credit Agreement (the "previous credit agreement") and the new credit agreement include:

- The extension of the maturity date to June 15, 2014 from August 15, 2011, subject to the following contingency:
  - If the Partnership's 8.375 percent senior notes due December 15, 2013 have not been refinanced or paid off by June 15, 2013, then the maturity date of the revolving credit facility will be June 15, 2013;
- An increase in the amount of allowed investments in HPC to $250,000,000 from $135,000,000;
- The addition of an allowance for joint venture investments (other than HPC) of up to $75,000,000, provided that (i) distributed cash and net income from joint ventures under this basket shall be excluded from consolidated net income and (ii) equity interests in joint ventures created under this basket shall be pledged as collateral;
- The modification of financial covenants to give credit for projected EBITDA associated with certain future material HPC projects on a percentage of completion basis, provided that such amount, together with adjustments related to the Haynesville Expansion Project and other material projects, does not exceed 20 percent of consolidated EBITDA (as defined in the new credit agreement) through March 31, 2010, and 15 percent thereafter;
- An increase in the annual general asset sales permitted from $20,000,000 annually to five percent of consolidated net tangible assets (as defined in the new credit agreement) annually.

The Partnership treated the amendment of the credit facility as a modification of an existing revolving credit agreement and, therefore, recorded a write-off of debt issuance costs of $1,780,000 that was recorded to interest expense, net in the three months ended March 31, 2010. In addition, the Partnership paid and capitalized $15,861,000 loan fees which will be amortized over the remaining term of the credit facility.

On May 26, 2010, the Partnership entered into the first amendment to its Fifth Amended and Restated Credit Agreement. The amendment, among other things,

- amends the definition of "Consolidated EBITDA" and "Consolidated Net Income" to include MEP;
- amends the definition of "Joint Venture" in the credit agreement to include MEP;
- amends the definition of "Permitted Acquisition" in the agreement to clarify that the initial investment in MEP is a permitted acquisition;
- amends the definition of "Permitted Holder" to include to include ETE as a party that may hold the equity interest in the Managing General Partner without triggering an event of default under the credit agreement;
- allows for the pledge of the equity interest in MEP as a collateral indirectly, through the direct pledge of equity interest in Regency Midcon Express LLC;
- permits certain investments in MEP by the Partnership and its affiliates;
- requires that the Partnership and its subsidiaries maintain a senior consolidated secured leverage ratio not to exceed 3 to 1.

The new credit agreement and the guarantees are senior to the Partnership's and the guarantors' secured obligations, including the Series A Preferred Units, to the extent of the value of the assets securing such obligations. As of June 30, 2010, the Partnership was in compliance with all of the financial covenants contained within the new credit agreement.

6. Commitments and Contingencies

Legal. The Partnership is involved in various claims and lawsuits incidental to its business. These claims and lawsuits in the aggregate are not expected to have a material adverse effect on the Partnership's business, financial condition, results of operations or cash flows.

Escrow Payable. At June 30, 2010, $1,011,000 remained in escrow pending the completion by El Paso of environmental remediation projects pursuant to the purchase and sale agreement ("El Paso PSA") related to assets in north Louisiana and the mid-continent area and a subsequent 2008 settlement agreement between the Partnership and El Paso. In the El Paso PSA, El Paso indemnified Regency Gas Services LLC, now known as Regency Gas Services LP, against losses arising from pre-closing and known environmental liabilities subject to a limit of $84,000,000 and certain deductible limits. Upon completion of a Phase II environmental study, the Partnership notified El Paso of remediation obligations amounting to $1,800,000 with respect to known environmental matters and $3,600,000 with respect to pre-closing environmental liabilities. This escrow amount will be further reduced under a specified schedule as El Paso completes its cleanup obligations and the remainder will be released upon completion. In connection with this matter, $500,000 was released on May 6, 2010.

Environmental. A Phase I environmental study was performed on certain assets located in west Texas in connection with the pre-acquisition due diligence process in 2004. Most of the identified environmental contamination had either been remediated or was being remediated by the previous owners or operators of the properties. The aggregate potential environmental remediation costs at specific locations were estimated to range from $1,900,000 to $3,100,000. No governmental agency has required the Partnership to undertake these remediation efforts. Management believes that the likelihood that it will be liable for any significant potential remediation liabilities identified in the study is remote. Separately, the Partnership acquired an environmental pollution liability insurance policy in connection with the acquisition to cover any undetected or unknown pollution discovered in the future. The policy covers clean-up costs and damages to third parties, and has a 10-year term (expiring 2014) with a $10,000,000 limit subject to certain deductibles. No claims have been made against the Partnership or under the policy.

Keyes Litigation. In August 2008, Keyes Helium Company, LLC ("Keyes") filed suit against Regency Gas Services LP, the Partnership, the General Partner and various other subsidiaries. Keyes entered into an output contract with the Partnership's predecessor-in-interest in 1996 under which it purchased all of the helium produced at the Lakin, Kansas processing plant. In September 2004, the Partnership decided to shut down its Lakin plant and contract with a third party for the processing of volumes processed at Lakin; as a result, the Partnership no longer delivered any helium to Keyes. In its suit, Keyes alleges it is entitled to damages for the costs of covering its purchases of helium. On May 7, 2010, the jury rendered a verdict in favor of Regency. No damages were awarded to the Plaintiffs. Plaintiffs have appealed the verdict. The hearing on appeal will take place sometime in 2011.

Kansas State Severance Tax. In August 2008, a customer began remitting severance tax to the state of Kansas based on the value of condensate purchased from one of the Partnership's Mid-Continent gathering fields and deducting the tax from its payments to the Partnership. The Kansas Department of Revenue advised the customer that it was appropriate to remit such taxes and withhold the taxes from its payments to the Partnership, absent an order or legal opinion from the Kansas Department of Revenue stating otherwise. The Partnership has requested a determination from the Kansas Department of Revenue regarding the matter since severance taxes were already paid on the gas from which the condensate is collected and no additional tax is due. The Kansas Department of Revenue has advised the Partnership that a portion of its condensate sales in Kansas is subject to severance tax; therefore the Partnership will be subject to additional taxes on future condensate sales. The Partnership may also be subject to additional taxes, interest and possible penalties for past condensate sales.

Remediation of Groundwater Contamination at Calhoun and Dubach Plants. Regency Field Services LLC ("RFS") currently owns the Dubach and Calhoun gas processing plants in north Louisiana (the "Plants"). The Plants each have groundwater contamination as result of historical operations. At the time that RFS acquired the Plants from El Paso Field Services LP ("El Paso"), Kerr-McGee Corporation ("Kerr-McGee") was performing remediation of the groundwater contamination, because the Plants were once owned by Kerr-McGee and when Kerr-McGee sold the Plants to a predecessor of El Paso in 1988, Kerr-McGee retained liability for any environmental contamination at the Plants. In 2005, Kerr-McGee created and spun off Tronox and Tronox allegedly assumed certain of Kerr-McGee's environmental remediation obligations (including its obligation to perform remediation at the Plants) prior to the acquisition of Kerr-McGee by Anadarko Petroleum Corporation. In January 2009, Tronox filed for Chapter 11 bankruptcy protection. RFS filed a claim in the bankruptcy proceeding relating to the environmental remediation work at the Plants. Tronox has thus far continued its remediation efforts at the Plants. Tronox filed a reorganization plan on July 7, 2010. The plan calls for the creation of a trust to fund environmental clean-up at the various sites where Tronox has an obligation. Tronox must file the Environmental Claims Settlement Agreement, which will set forth the amount of trust funds allocated to each site, 14 days prior to the confirmation hearing, the date for which has not yet been set.

7. Series A Convertible Redeemable Preferred Units

On September 2, 2009, the Partnership issued 4,371,586 Series A Preferred Units. As of March 31, 2010, the Series A Preferred Units were convertible to 4,584,192 common units, and if outstanding, are mandatorily redeemable on September 2, 2029 for $80,000,000 plus all accrued but unpaid distributions thereon. The Series A Preferred Units will receive fixed quarterly cash distributions of $0.445 per unit beginning with the quarter ending March 31, 2010, if outstanding on the record dates of the Partnership's common units distributions. Effective as of March 2, 2010, holders can elect to convert Series A Preferred Units to common units at any time in accordance with the partnership agreement.

Upon a change in control, each unitholder may, at its option, require the Partnership to purchase the Series A Preferred Units for an amount equal to 101 percent of the total of the face value of the Series A Preferred Units plus all accrued but unpaid distribution thereon. Subsequent to the ETE Acquisition, no unitholder has exercised this option.

As disclosed in Note 1, the Partnership's Series A Preferred Units were adjusted to its fair value of $70,793,000 on May 26, 2010. The following table provides a reconciliation of the beginning and ending balances of the Series A Preferred Units for the six months ended June 30, 2010.

	For the Six Months Ended June 30, 2010,	
	Units	Amount (in thousands)
Beginning balance as of January 1, 2010	4,371,586	$ 51,711
Accretion to redemption value from January 1, 2010 to May 25, 2010	—	55
Balance as of May 25, 2010	4,371,586	51,766
Fair value adjustment	—	19,027
Balance as of May 26, 2010	4,371,586	70,793
Accretion to redemption value from May 26, 2010 to June 30, 2010	—	57
Ending balance as of June 30, 2010	4,371,586	$ 70,850*

* This amount will be accreted to $80,000,000 plus any accrued and unpaid distributions by deducting amounts from partners' capital over the 19.25 remaining years.

8. Related Party Transactions

The employees operating the assets of the Partnership and its subsidiaries and all those providing staff or support services are employees of the General Partner. Pursuant to the Partnership Agreement, the General Partner receives a monthly reimbursement for all direct and indirect expenses incurred on behalf of the Partnership. Reimbursements of $5,660,000, $10,370,000, $31,065,000, $8,591,000 and $16,209,000, were recorded in the Partnership's financial statements during the periods from May 26, 2010 to June 30, 2010, from April 1, 2010 to May 25, 2010, from January 1, 2010 to May 25, 2010 and for the three and six months ended June 30, 2009, respectively, as operating expenses or general and administrative expenses, as appropriate.

In conjunction with distributions by the Partnership to its limited and general partner interests, GE EFS received cash distributions of $13,114,000, $2,603,000, $26,241,000 and $12,181,000 during the period from April 1, 2010 to May 25, 2010, the three months ended June 30, 2009, the period from January 1, 2010 to May 25, 2010 and the six months ended June 30, 2009, respectively.

Under a Master Services Agreement with HPC, the Partnership operates and provides all employees and services for the operation and management of HPC. Under this agreement, the Partnership receives $1,400,000 monthly as a partial reimbursement of its general and administrative costs. The amount is recorded as fee revenue in the Partnership's corporate and other segment. The Partnership also incurs expenditures on behalf of HPC and these amounts are billed to HPC on a monthly basis. For the periods from May 26, 2010 to June 30, 2010, from April 1, 2010 to May 25, 2010, from January 1, 2010 to May 25, 2010, and the three and six months ended June 30, 2009, the related party general and administrative expenses reimbursed to the Partnership were $1,400,000, $2,800,000, $6,933,000, $1,500,000, and $1,726,000, respectively.

On May 26, 2010, the Partnership received $7,436,000 from ETE, which represents the portion of the estimated amount of the Partnership's common unit distribution to be paid to ETE for the period of time those units were not outstanding (April 1, 2010 to May 25, 2010).

As of June 30, 2010, the Partnership has a related party receivable of $12,288,000 from ETE for an additional capital contribution, which was received on August 6, 2010.

On May 26, 2010, the Partnership entered into a services agreement with ETE and ETE Services Company, LLC ("Services Co."), a subsidiary of ETE. Under the services agreement, Services Co. will perform certain general and administrative services to the Partnership. The Partnership will pay Services Co's direct expenses for these services, plus an annual fee of $10,000,000, and will receive the benefit of any cost savings recognized for these services. The services agreement has a five year term, subject to earlier termination rights in the event of a change in control, the failure to achieve certain cost savings for the Partnership or upon an event of default.

As disclosed in Note 2, the Partnership’s acquisition of additional 6.99 percent partner’s interest in HPC from GE EFS, and the 49.9 percent interest in MEP from ETE are related party transactions.

The Partnership’s contract compression segment provides contract compression services to HPC and records revenue in gathering, transportation and other fees on the statement of operation. The Partnership also receives transportation services from HPC and records the cost as cost of sales.

Enterprise GP holds a non-controlling equity interest in ETE’s general partner and a limited partnership interest in ETE, therefore is considered a related party along with any of its subsidiaries. The Partnership, in the ordinary course of business, sells natural gas and NGLs to the subsidiaries of Enterprise GP and records the revenue in gas sales and NGL sales. The Partnership also incurs NGL processing fees with subsidiaries of Enterprise GP and records the cost to cost of sales.

As of June 30, 2010, the Partnership’s related party receivables and related party payables included $18,501,000 and $422,000, respectively, from and to subsidiaries of Enterprise GP.

9. Segment Information

In 2009, the Partnership’s management realigned the composition of its segments. Accordingly, the Partnership has restated the items of segment information for earlier periods to reflect this new alignment.

The Partnership has four reportable segments: (a) gathering and processing, (b) transportation, (c) contract compression and (d) corporate and others. Gathering and processing involves collecting raw natural gas from producer wells and transporting it to treating plants where water and other impurities such as hydrogen sulfide and carbon dioxide are removed. Treated gas is then processed to remove the natural gas liquids. The treated and processed natural gas is then transported to market separately from the natural gas liquids. Revenues and the associated cost of sales from the gathering and processing segment directly expose the Partnership to commodity price risk, which is managed through derivative contracts and other measures. The Partnership aggregates the results of its gathering and processing activities across five geographic regions into a single reporting segment. The Partnership, through its producer services function, primarily purchases natural gas from producers at gathering systems and plants connected to its pipeline systems and sells this gas at downstream outlets.

The transportation segment consists of the Partnership’s 49.99 percent interest in HPC, which we operate, and the 49.9 percent interest in MEP. Prior periods have been restated to reflect the Partnership’s then wholly-owned subsidiary of Regency Intrastate Gas LLC (“RIG”) as the exclusive reporting unit within this segment. The transportation segment uses pipelines to transport natural gas from receipt points on its system to interconnections with other pipelines, storage facilities or end-use markets. RIG performs transportation services for shipping customers under firm or interruptible arrangements. In either case, revenues are primarily fee based and involve minimal direct exposure to commodity price fluctuations. The north Louisiana intrastate pipeline operated by this segment serves the Partnership’s gathering and processing facilities in the same area and those transactions create a portion of the intersegment revenues shown in the table below.

The contract compression segment provides customers with turn-key natural gas compression services to maximize their natural gas and crude oil production, throughput, and cash flow. The Partnership’s integrated solutions include a comprehensive assessment of a customer’s natural gas contract compression needs and the design and installation of a compression system that addresses those particular needs. The Partnership is responsible for the installation and on-going operation, service, and repair of its compression units, which are modified as necessary to adapt to customers’ changing operating conditions. The contract compression segment also provides services to certain operations in the gathering and processing segment, creating a portion of the intersegment revenues shown in the table below.

The corporate and others segment comprises regulated entities and the Partnership’s corporate offices. Revenues in this segment include the collection of the partial reimbursement of general and administrative costs from HPC.

Management evaluates the performance of each segment and makes capital allocation decisions through the separate consideration of segment margin and operation and maintenance expenses. Segment margin, for the gathering and processing and for the transportation segments, is defined as total revenues, including service fees, less cost of sales. In the contract compression segment, segment margin is defined as revenues minus direct costs, which primarily consist of compressor repairs. Management believes segment margin is an important measure because it directly relates to volume, commodity price changes and revenues generating horsepower. Operation and maintenance expenses are a separate measure used by management to evaluate performance of field operations. Direct labor, insurance, property taxes, repair and maintenance, utilities and contract services comprise the most significant portion of operation and maintenance expenses. These expenses fluctuate depending on the activities performed during a specific period. The Partnership does not deduct operation and maintenance expenses from total revenues in calculating segment margin because management separately evaluates commodity volume and price changes in segment margin.

Results for each period, together with amounts related to balance sheets for each segment, are shown below.

	Gathering and Processing	Transportation	Contract Compression	Corporate and Others	Eliminations	Total
			(in thousands)			
External Revenues						
Period from May 26, 2010 to June 30, 2010	$ 90,147	$ —	$ 12,053	$ 780	$ —	$ 102,980
Period from April 1, 2010 to May 25, 2010	183,582	—	23,992	3,921	—	211,495
For the three months ended June 30, 2009	209,939	1,531	39,011	3,061	—	253,542
Period from January 1, 2010 to May 25, 2010	460,423	—	58,971	9,853	—	529,247
For the six months ended June 30, 2009	453,093	9,075	77,499	3,853	—	543,520
Intersegment Revenues						
Period from May 26, 2010 to June 30, 2010	—	—	1,999	22	(2,021)	—
Period from April 1, 2010 to May 25, 2010	—	—	3,794	53	(3,847)	—
For the three months ended June 30, 2009	(6,745)	(128)	975	40	5,858	—
Period from January 1, 2010 to May 25, 2010	—	—	9,126	91	(9,217)	—
For the six months ended June 30, 2009	(8,755)	4,936	1,785	144	1,890	—
Cost of Sales						
Period from May 26, 2010 to June 30, 2010	73,311	—	1,564	(772)	(22)	74,081
Period from April 1, 2010 to May 25, 2010	144,768	—	2,460	87	(53)	147,262
For the three months ended June 30, 2009	144,816	1,243	4,186	269	6,833	157,347
Period from January 1, 2010 to May 25, 2010	366,900	—	5,741	(679)	(91)	371,871
For the six months ended June 30, 2009	327,284	2,297	6,504	116	3,674	339,875
Segment Margin						
Period from May 26, 2010 to June 30, 2010	16,836	—	12,488	1,574	(1,999)	28,899
Period from April 1, 2010 to May 25, 2010	38,814	—	25,326	3,887	(3,794)	64,233
For the three months ended June 30, 2009	58,378	160	35,800	2,832	(975)	96,195
Period from January 1, 2010 to May 25, 2010	93,523	—	62,356	10,623	(9,126)	157,376
For the six months ended June 30, 2009	117,054	11,714	72,780	3,881	(1,784)	203,645
Operation and Maintenance						
Period from May 26, 2010 to June 30, 2010	8,814	—	4,924	203	(1,999)	11,942
Period from April 1, 2010 to May 25, 2010	15,400	—	9,698	126	(3,794)	21,430
For the three months ended June 30, 2009	22,044	(174)	11,487	(181)	(1,202)	31,974
Period from January 1, 2010 to May 25, 2010	39,161	—	23,476	327	(9,123)	53,841
For the six months ended June 30, 2009	44,349	2,112	24,028	132	(2,605)	68,016
Depreciation and Amortization						
Period from May 26, 2010 to June 30, 2010	7,413	—	3,323	259		10,995
Period from April 1, 2010 to May 25, 2010	11,576	—	6,353	680	—	18,609
For the three months ended June 30, 2009	16,413	—	8,955	868	—	26,236
Period from January 1, 2010 to May 25, 2010	28,864	—	15,560	1,660	—	46,084
For the six months ended June 30, 2009	33,134	2,448	16,982	1,561	—	54,125
Income from Unconsolidated Subsidiaries						
Period from May 26, 2010 to June 30, 2010	—	8,121	—	—		8,121
Period from April 1, 2010 to May 25, 2010	—	7,959	—	—	—	7,959
For the three months ended June 30, 2009	—	1,587	—	—	—	1,587
Period from January 1, 2010 to May 25, 2010	—	15,872	—	—		15,872
For the six months ended June 30, 2009	—	1,923	—	—	—	1,923
Assets						
June 30, 2010	1,751,253	1,369,921	1,362,549	111,570	—	4,595,293
December 31, 2009	1,046,619	453,120	926,213	107,463	—	2,533,415
Investment in Unconsolidated Subsidiaries						
June 30, 2010	—	1,369,921	—	—	—	1,369,921
December 31, 2009	—	453,120	—	—	—	453,120
Goodwill						
June 30, 2010	286,634	—	447,040	—	—	733,674
December 31, 2009	63,232	—	164,882	—	—	228,114
Expenditures for Long-Lived Assets						
Period from May 26, 2010 to June 30, 2010	15,300	—	5,208	367	—	20,875
Period from January 1, 2010 to May 25, 2010	43,666	—	18,418	1,703		63,787
For the six months ended June 30, 2009	44,639	22,367	50,959	1,220	—	119,185

The table below provides a reconciliation of total segment margin to net income (loss) from continuing operations.

	Successor	Predecessor			
	Period from Acquisition (May 26, 2010) to June 30, 2010	Period from April 1, 2010 to Disposition (May 25, 2010)	Three Months Ended June 30, 2009	Period from January 1, 2010 to Disposition (May 25, 2010)	Six Months Ended June 30, 2009
	(in thousands)	(in thousands)			
Net income attributable to Regency GP LP	$ 803	$ —	$ 741	$ 662	$ 4,274
Add (deduct):					
Operation and maintenance	11,942	21,430	31,974	53,841	68,016
General and administrative	7,104	21,809	14,127	37,212	29,205
Loss (gain) on asset sales, net	10	19	651	303	(133,280)
Depreciation and amortization	10,995	18,609	26,236	46,084	54,125
Income from unconsolidated subsidiaries	(8,121)	(7,959)	(1,587)	(15,872)	(1,923)
Interest expense, net	8,109	14,114	19,568	36,459	33,795
Other income and deductions, net	3,510	624	(214)	3,891	(256)
Income tax expense (benefit)	245	83	(515)	404	(416)
Net (loss) income attributable to the noncontrolling interest	(5,698)	(4,496)	5,214	(5,608)	150,105
Total segment margin	$ 28,899	$ 64,233	$ 96,195	$ 157,376	$ 203,645

10. Equity-Based Compensation

The Partnership's Long-Term Incentive Plan ("LTIP") for its employees, directors and consultants authorizes grants up to 2,865,584 common units. Because control changed from GE EFS to ETE, all then outstanding LTIP, exclusive of the May 7, 2010 phantom unit grant described below, vested during the predecessor period and the Partnership recorded a one-time general and administrative charge of $9,893,000 as a result of the vesting of these units on May 25, 2010. LTIP compensation expense of $137,000, $10,431,000, $12,070,000, $1,561,000 and $2,750,000 is recorded in general and administrative expense in the statement of operations for the periods from May 26, 2010 to June 30, 2010, April 1, 2010 to May 25, 2010 and January 1, 2010 to May 25, 2010, and for the three and six months ended June 30, 2009, respectively.

Common Unit Option and Restricted (Non-Vested) Units.

The common unit options activity for the six months ended June 30, 2010 is as follows.

Common Unit Options	Units	Weighted Average Exercise Price	Weighted Average Contractual Term (Years)	Aggregate Intrinsic Value *(in thousands)
Outstanding at the beginning of period	306,651	$ 21.50		
Granted	—	—		
Exercised	(13,500)	20.00		
Forfeited or expired	(3,001)	23.73		
Outstanding at end of period	290,150	21.57	5.8	833
Exercisable at the end of the period	290,150			833

* Intrinsic value equals the closing market price of a unit less the option strike price, multiplied by the number of unit options outstanding as of the end of the period presented, unit options with an exercise price greater than the end of the period closing market price are excluded.

During the six months ended June 30, 2010, the Partnership received $270,000 in proceeds from the exercise of unit options.

The restricted (non-vested) common unit activity for the six months ended June 30, 2010 is as follows.

Restricted (Non-Vested) Common Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	464,009	$ 28.36
Granted	—	—
Vested	(444,759)	28.19
Forfeited or expired	(19,250)	32.35
Outstanding at the end of period	—	—

Phantom Units. The Partnership's phantom units are in substance two grants composed of (1) service condition grants with graded vesting over three years; and (2) market condition grants with cliff vesting based upon the Partnership's relative ranking in total unitholder return among 20 peer companies, as disclosed in Item 11 of the Partnership's Annual Report on Form 10-K for the year ended December 31, 2009. As control changed from GE EFS to ETE, all outstanding phantom units, exclusive of the May 7, 2010 grant described below, vested. The service condition grants vested at a rate of 100 percent and the market condition grants vested at a rate of 150 percent pursuant to the terms of the award.

The Partnership awarded 247,500 phantom units to senior management and certain key employees on May 7, 2010. These phantom units include a provision that will accelerate vesting (1) upon a change in control and (2) within 12 months of a change in control, if termination without "Cause" (as defined) or resignation for "Good Reason" (as defined) occurs, the phantom units will vest. The Partnership expects to recognize $3,187,000 of compensation expense related to non-vested phantom units over a period of 2.8 years.

The following table presents phantom unit activity for the six months ended June 30, 2010.

Phantom Units	Units	Weighted Average Grant Date Fair Value
Outstanding at the beginning of the period	301,700	$ 8.63
Service condition grants	108,500	20.76
Market condition grants	148,500	11.89
Vested service condition	(138,313)	13.97
Vested market condition	(168,420)*	4.65
Forfeited service condition	(6,467)	19.30
Forfeited market condition	(10,500)	10.20
Total outstanding at end of period	235,000	16.31

* Upon the change in control, these awards converted into 252,630 common units.

11. Fair Value Measures

The fair value measurement provisions establish a three-tiered fair value hierarchy that prioritizes inputs to valuation techniques used in fair value calculations. The three levels of inputs are defined as follows:

- Level 1—unadjusted quoted prices for identical assets or liabilities in active accessible markets;
- Level 2— inputs that are observable in the marketplace other than those classified as Level 1; and
- Level 3—inputs that are unobservable in the marketplace and significant to the valuation.

Entities are encouraged to maximize the use of observable inputs and minimize the use of unobservable inputs. If a financial instrument uses inputs that fall in different levels of the hierarchy, the instrument will be categorized based upon the lowest level of input that is significant to the fair value calculation.

Derivatives. The Partnership's financial assets and liabilities measured at fair value on a recurring basis are derivatives related to commodity swaps and embedded derivatives in the Series A Preferred Units. Derivatives related to commodity swaps are valued using discounted cash flow techniques. These techniques incorporate Level 1 and Level 2 inputs such as future interest rates and commodity prices. These market inputs are utilized in the discounted cash flow calculation considering the instrument's term, notional amount, discount rate and credit risk and are classified as Level 2 in the hierarchy. Derivatives related to Series A Preferred Units are valued using a binomial lattice model. The market inputs utilized in the model include credit spread, probabilities of the occurrence of certain events, common unit price, dividend yield, and expected volatility, and are classified as Level 3 in the hierarchy. The change in fair value of the derivatives related to Series A Preferred Units is recorded in other income and deductions, net within the statement of operations.

The following table presents the Partnership's derivative assets and liabilities measured at fair value on a recurring basis.

	Fair Value Measurement at June 30, 2010				Fair Value Measurement at December 31, 2009			
	Fair Value Total	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value Total	Quoted Prices in Active Markets (Level 1)	Significant Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
	(in thousands)							
Assets								
Commodity Derivatives:								
Natural Gas	3,125	—	3,125	—	602	—	602	—
Natural Gas Liquids	12,222	—	12,222	—	15,484	—	15,484	—
Condensate	5,727	—	5,727	—	9,108	—	9,108	—
Total Assets	21,074	—	21,074	—	25,194	—	25,194	—
Liabilities								
Interest rate swaps	1,877	—	1,877	—	1,064	—	1,064	—
Commodity Derivatives:		—		—		—		—
Natural Gas	15	—	15	—	51	—	51	—
Natural Gas Liquids	2,025	—	2,025	—	15,034	—	15,034	—
Condensate	29	—	29	—	416	—	416	—
Series A Preferred Units	52,239	—	—	52,239	44,594	—	—	44,594
Total Liabilities	56,185	—	3,946	52,239	61,159	—	16,565	44,594

The following table presents the changes in Level 3 derivatives measured on a recurring basis for the six months ended June 30, 2010.

	Derivatives related to Series A Preferred Units
	(in thousands)
Beginning Balance- December 31, 2009	$ 44,594
Net unrealized losses included in other income and deductions, net	4,039
Ending Balance- May 25, 2010	48,633
Net unrealized losses included in other income and deductions, net	3,606
Ending Balance- June 30, 2010	$ 52,239

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximates fair value due to their short-term maturities. Restricted cash and related escrow payable approximates fair value due to the relatively short-term settlement period of the escrow payable. Long-term debt, other than the senior notes, is comprised of borrowings which incur interest under a floating interest rate structure. Accordingly, the carrying value approximates fair value. The estimated fair values of the senior notes due 2013 and 2016, based on third party market value quotations as of June 30, 2010, were $369,119,000 and $265,000,000, respectively.

12. Subsequent Events

On July 27, 2010, the Partnership declared a distribution of $0.445 per outstanding common unit and Series A Preferred Unit, including units equivalent to the General Partner's two percent interest in the Partnership, and a distribution with respect to incentive distribution rights of approximately $915,000, payable on August 13, 2010, to unitholders of record at the close of business on August 6, 2010.

On July 15, 2010, the Partnership sold its gathering and processing assets located in east Texas to an affiliate of Tristream Energy LLC for approximately $70,000,000. The Partnership plans to use the proceeds from the sale of the assets to fund future capital expenditures.

On September 1, 2010, the Partnership acquired Zephyr Gas Services, LLC, a field services company for approximately $185,000,000.

On August 16, 2010, the Partnership issued 17,537,500 common units representing limited partner interests at $23.80 per common unit.

Management has evaluated subsequent events from the balance sheet date through September 13, 2010, the date the financial statements were available to be issued.