Energy Transfer Partners, L.P.
Form 10-Q
November 08, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

or

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

Commission file number 1-11727

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

| | |
|---|---|
| Delaware<br>(state or other jurisdiction of<br>incorporation or organization) | 73-1493906<br>(I.R.S. Employer<br>Identification No.) |

3738 Oak Lawn Avenue, Dallas, Texas 75219
(Address of principal executive offices) (zip code)
(214) 981-0700
(Registrant's telephone number, including area code)

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

| | | | |
|---|---|---|---|
| Large accelerated filer | ý | Accelerated filer | ¨ |
| Non-accelerated filer | ¨ (Do not check if a smaller reporting company) | Smaller reporting company | ¨ |

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

At October 31, 2012, the registrant had units outstanding as follows:

| | | |
|---|---|---|
| Energy Transfer Partners, L.P. | 300,547,400 | Common Units |

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Energy Transfer Partners, L.P. and Subsidiaries

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Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (“Energy Transfer Partners,” the “Partnership,” or "ETP") in periodic press releases and some oral statements of the Partnership’s officials during presentations about the Partnership, include forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. Statements using words such as “anticipate,” “believe,” “intend,” “project,” “plan,” “expect,” “continue,” “esti “goal,” “forecast,” “may,” “will” or similar expressions help identify forward-looking statements. Although the Partnership and its General Partner believe such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that such assumptions, expectations, or projections will prove to be correct. Forward-looking statements are subject to a variety of risks, uncertainties and assumptions. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, the Partnership’s actual results may vary materially from those anticipated, projected or expected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks that are difficult to predict and beyond management’s control. For additional discussion of risks, uncertainties and assumptions, see “Part II — Other Information – Item 1A. Risk Factors” in this Quarterly Report on Form 10-Q and our Quarterly Report on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012, as well as “Part I — Item 1A. Risk Factors” in the Partnership’s Report on Form 10-K for the year ended December 31, 2011 filed with the Securities and Exchange Commission on February 22, 2012.

Definitions

The following is a list of certain acronyms and terms generally used throughout this document:

| | |
|---|---|
| /d | per day |
| AmeriGas | AmeriGas Partners, L.P. |
| AOCI | accumulated other comprehensive income (loss) |
| Bbls | barrels |
| Bcf | billion cubic feet |
| Btu | British thermal unit, an energy measurement used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used |
| CAA | Clean Air Act |
| Capacity | capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels |
| DOT | U.S. Department of Transportation |
| El Paso | El Paso Corporation |
| Enterprise | Enterprise Products Partners L.P., together with its subsidiaries |
| ETC Compression | ETC Compression, LLC |

| | |
|---|---|
| ETC FEP | ETC Fayetteville Express Pipeline, LLC |
| ETC OLP | La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company |
| ETC Tiger | ETC Tiger Pipeline, LLC |
| ETE | Energy Transfer Equity, L.P., a publicly traded partnership and the owner of ETP LLC |
| ET Interstate | Energy Transfer Interstate Holdings, LLC |
| ETP GP | Energy Transfer Partners GP, L.P., the general partner of ETP |
| ETP LLC | Energy Transfer Partners, L.L.C., the general partner of ETP GP |
| EPA | U.S. Environmental Protection Agency |

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| | |
|---|---|
| Exchange Act | Securities Exchange Act of 1934 |
| FEP | Fayetteville Express Pipeline LLC |
| FERC | Federal Energy Regulatory Commission |
| FGT | Florida Gas Transmission Company, LLC |
| GAAP | accounting principles generally accepted in the United States of America |
| Holdco | ETP Holdco Corporation |
| HOLP | Heritage Operating, L.P. |
| ICA | Interstate Commerce Act |
| IDRs | incentive distribution rights |
| LDH | LDH Energy Asset Holdings LLC |
| LIBOR | London Interbank Offered Rate |
| Lone Star | Lone Star NGL LLC |
| MMBtu | million British thermal units |
| NGA | Natural Gas Act |
| NGL | natural gas liquid, such as propane, butane and natural gasoline |
| NYMEX | New York Mercantile Exchange |
| OTC | over-the-counter |
| OSHA | federal Occupational Safety and Health Act |
| PCBs | polychlorinated biphenyls |
| PHMSA | Pipeline Hazardous Materials Safety Administration |
| Regency | Regency Energy Partners LP, a subsidiary of ETE |
| Reservoir | a porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs |
| SEC | Securities and Exchange Commission |

| | |
|---|---|
| Southern Union | Southern Union Company, a subsidiary of ETE |
| Sunoco | Sunoco, Inc. |
| Sunoco Logistics | Sunoco Logistics Partners L.P. |
| Tcf | trillion cubic feet |
| Titan | Titan Energy Partners, L.P. |
| Transwestern | Transwestern Pipeline Company, LLC |

Adjusted EBITDA is a term used throughout this document, which we define as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on proportionate ownership.

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PART I — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| ASSETS | | |
| CURRENT ASSETS: | | |
| Cash and cash equivalents | $110,354 | $106,816 |
| Accounts receivable, net of allowance for doubtful accounts of $538 and $7,651 as of September 30, 2012 and December 31, 2011, respectively | 541,345 | 568,579 |
| Accounts receivable from related companies | 45,165 | 81,753 |
| Inventories | 234,203 | 306,740 |
| Exchanges receivable | 18,837 | 18,808 |
| Price risk management assets | 18,007 | 11,429 |
| Current assets held for sale | 7,482 | — |
| Other current assets | 114,324 | 181,369 |
| Total current assets | 1,089,717 | 1,275,494 |
| | | |
| PROPERTY, PLANT AND EQUIPMENT | 14,238,264 | 13,983,888 |
| ACCUMULATED DEPRECIATION | (1,379,944) | (1,677,522) |
| | 12,858,320 | 12,306,366 |
| | | |
| NON-CURRENT ASSETS HELD FOR SALE | 190,996 | — |
| ADVANCES TO AND INVESTMENTS IN UNCONSOLIDATED AFFILIATES | 3,197,520 | 200,612 |
| NON-CURRENT PRICE RISK MANAGEMENT ASSETS | 41,879 | 25,537 |
| GOODWILL | 600,152 | 1,219,597 |
| INTANGIBLE ASSETS, net | 161,847 | 331,409 |
| OTHER NON-CURRENT ASSETS, net | 157,129 | 159,601 |
| Total assets | $18,297,560 | $15,518,616 |

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(Dollars in thousands)
(unaudited)

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| LIABILITIES AND EQUITY | | |
| CURRENT LIABILITIES: | | |
| Accounts payable | $381,338 | $401,053 |
| Accounts payable to related companies | 7,977 | 33,373 |
| Exchanges payable | 13,822 | 17,906 |
| Price risk management liabilities | 88,770 | 79,518 |
| Accrued and other current liabilities | 723,135 | 629,202 |
| Current maturities of long-term debt | 350,000 | 424,117 |
| Current liabilities held for sale | 5,439 | — |
| Total current liabilities | 1,570,481 | 1,585,169 |
| LONG-TERM DEBT, less current maturities | 8,690,740 | 7,388,170 |
| NON-CURRENT PRICE RISK MANAGEMENT LIABILITIES | 72,660 | 42,303 |
| OTHER NON-CURRENT LIABILITIES | 174,351 | 152,550 |
| COMMITMENTS AND CONTINGENCIES (Note 14) | | |
| EQUITY: | | |
| General Partner | 190,237 | 181,646 |
| Limited Partners: | | |
| Common Unitholders | 6,733,310 | 5,533,492 |
| Accumulated other comprehensive income (loss) | (10,351) | 6,569 |
| Total partners' capital | 6,913,196 | 5,721,707 |
| Noncontrolling interest | 876,132 | 628,717 |
| Total equity | 7,789,328 | 6,350,424 |
| Total liabilities and equity | $18,297,560 | $15,518,616 |

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
(Dollars in thousands, except per unit data)
(unaudited)

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 |
|---|---|---|---|---|
| REVENUES: | | | | |
| Natural gas sales | $603,449 | $679,889 | $1,480,729 | $1,963,135 |
| NGL sales | 326,841 | 333,078 | 1,011,735 | 756,740 |
| Gathering, transportation and other fees | 399,494 | 392,080 | 1,162,386 | 1,094,762 |
| Retail propane sales | — | 213,496 | 87,082 | 962,258 |
| Other | 90,690 | 82,920 | 198,830 | 217,085 |
| Total revenues | 1,420,474 | 1,701,463 | 3,940,762 | 4,993,980 |
| COSTS AND EXPENSES: | | | | |
| Cost of products sold | 886,888 | 1,070,076 | 2,319,318 | 3,067,316 |
| Operating expenses | 99,602 | 193,364 | 349,465 | 563,917 |
| Depreciation and amortization | 94,812 | 106,419 | 282,485 | 294,356 |
| Selling, general and administrative | 47,295 | 57,745 | 151,310 | 158,000 |
| Total costs and expenses | 1,128,597 | 1,427,604 | 3,102,578 | 4,083,589 |
| OPERATING INCOME | 291,877 | 273,859 | 838,184 | 910,391 |
| OTHER INCOME (EXPENSE): | | | | |
| Interest expense, net of interest capitalized | (112,141) | (124,000) | (383,271) | (347,706) |
| Equity in earnings of unconsolidated affiliates | 7,920 | 6,713 | 63,011 | 13,386 |
| Gain on deconsolidation of Propane Business | — | — | 1,056,709 | — |
| Loss on extinguishment of debt | — | — | (115,023) | — |
| Losses on non-hedged interest rate derivatives | (65) | (68,595) | (8,087) | (64,705) |
| Other, net | 6,548 | (6,345) | 9,547 | (6,559) |
| INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAX EXPENSE | 194,139 | 81,632 | 1,461,070 | 504,807 |
| Income tax expense | 768 | 4,039 | 14,915 | 20,417 |
| INCOME FROM CONTINUING OPERATIONS | 193,371 | 77,593 | 1,446,155 | 484,390 |
| Loss from discontinued operations | (147,162) | (1,543) | (150,062) | (4,522) |
| NET INCOME | 46,209 | 76,050 | 1,296,093 | 479,868 |
| LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST | 9,184 | 9,285 | 32,914 | 17,673 |
| NET INCOME ATTRIBUTABLE TO PARTNERS | 37,025 | 66,765 | 1,263,179 | 462,195 |
| GENERAL PARTNER’S INTEREST IN NET INCOME | 116,583 | 104,810 | 341,925 | 318,241 |
| LIMITED PARTNERS’ INTEREST IN NET INCOME (LOSS) | $(79,558) | $(38,045) | $921,254 | $143,954 |
| INCOME (LOSS) FROM CONTINUING OPERATIONS PER LIMITED PARTNER UNIT: | | | | |
| Basic | $0.26 | $(0.18) | $4.54 | $0.70 |
| Diluted | $0.26 | $(0.18) | $4.52 | $0.70 |
| NET INCOME (LOSS) PER LIMITED PARTNER UNIT: | | | | |
| Basic | $(0.33) | $(0.19) | $3.91 | $0.68 |
| Diluted | $(0.33) | $(0.19) | $3.89 | $0.68 |

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Dollars in thousands)
(unaudited)

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Net income | $46,209 | $76,050 | $1,296,093 | $479,868 |
| Other comprehensive income (loss), net of tax: | | | | |
| Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges | (3,539) | (4,994) | (13,636) | (27,405) |
| Change in value of derivative instruments accounted for as cash flow hedges | (3,363) | 6,126 | 10,508 | 14,583 |
| Change in value of available-for-sale securities | — | (900) | (114) | (935) |
| Change in other comprehensive income (loss) from equity investments | 8,728 | — | (13,678) | — |
| | 1,826 | 232 | (16,920) | (13,757) |
| Comprehensive income | 48,035 | 76,282 | 1,279,173 | 466,111 |
| Less: Comprehensive income attributable to noncontrolling interest | 9,184 | 9,285 | 32,914 | 17,673 |
| Comprehensive income attributable to partners | $38,851 | $66,997 | $1,246,259 | $448,438 |

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF EQUITY
FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2012
(Dollars in thousands)
(unaudited)

| | General Partner | Limited Partner Common Unitholders | Accumulated Other Comprehensive Income (Loss) | Noncontrolling Interest | Total |
|---|---|---|---|---|---|
| Balance, December 31, 2011 | $181,646 | $5,533,492 | $ 6,569 | $ 628,717 | $6,350,424 |
| Distributions to partners | (333,053) | (626,545) | — | — | (959,598) |
| Distributions to noncontrolling interest | — | — | — | (38,794) | (38,794) |
| Units issued for cash | — | 771,813 | — | — | 771,813 |
| Capital contributions from noncontrolling interest | — | — | — | 253,295 | 253,295 |
| Units issued in connection with acquisitions | — | 112,000 | — | — | 112,000 |
| Non-cash compensation expense, net of units tendered by employees for tax withholdings | 19 | 30,266 | — | — | 30,285 |
| Other comprehensive loss, net of tax | — | — | (16,920) | — | (16,920) |
| Other, net | (300) | (8,970) | — | — | (9,270) |
| Net income | 341,925 | 921,254 | — | 32,914 | 1,296,093 |
| Balance, September 30, 2012 | $190,237 | $6,733,310 | $ (10,351) | $ 876,132 | $7,789,328 |

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Dollars in thousands)
(unaudited)

| | Nine Months Ended September 30, 2012 | 2011 |
|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES: | | |
| Net income | $1,296,093 | $479,868 |
| Reconciliation of net income to net cash provided by operating activities: | | |
| Depreciation and amortization | 282,485 | 294,356 |
| Amortization of finance costs charged to interest | 7,774 | 7,199 |
| Loss on extinguishment of debt | 115,023 | — |
| Non-cash compensation expense | 30,190 | 31,139 |
| Gain on deconsolidation of Propane Business | (1,056,709) | — |
| Write-down of assets included in loss from discontinued operations (see Note 3) | 145,214 | — |
| Distributions on unvested awards | (6,049) | (5,687) |
| Equity in earnings of unconsolidated affiliates | (63,011) | (13,386) |
| Distributions from unconsolidated affiliates | 93,792 | 15,563 |
| Other non-cash | 32,869 | 26,110 |
| Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation (see Note 4) | 60,264 | 195,047 |
| Net cash provided by operating activities | 937,935 | 1,030,209 |
| CASH FLOWS FROM INVESTING ACTIVITIES: | | |
| Cash paid for Citrus Merger (See Note 6) | (1,895,000) | — |
| Cash proceeds from contribution and sale of propane operations | 1,442,536 | — |
| Cash paid for all other acquisitions, net of cash received | (10,317) | (1,971,438) |
| Capital expenditures (excluding allowance for equity funds used during construction) | (1,797,467) | (950,978) |
| Contributions in aid of construction costs | 28,022 | 18,435 |
| Contributions to unconsolidated affiliates | (2,050) | (221,365) |
| Distributions from unconsolidated affiliates in excess of cumulative earnings | 95,184 | 15,731 |
| Proceeds from the sale of assets | 13,172 | 6,516 |
| Net cash used in investing activities | (2,125,920) | (3,103,099) |
| CASH FLOWS FROM FINANCING ACTIVITIES: | | |
| Proceeds from borrowings | 4,462,287 | 5,283,107 |
| Repayments of long-term debt | (3,266,160) | (3,644,454) |
| Net proceeds from issuance of Limited Partner units | 771,813 | 799,292 |
| Capital contributions received from noncontrolling interest | 240,115 | 616,311 |
| Distributions to partners | (959,598) | (863,511) |
| Distributions to noncontrolling interest | (38,794) | (18,900) |
| Debt issuance costs | (18,140) | (12,262) |
| Net cash provided by financing activities | 1,191,523 | 2,159,583 |
| INCREASE IN CASH AND CASH EQUIVALENTS | 3,538 | 86,693 |
| CASH AND CASH EQUIVALENTS, beginning of period | 106,816 | 49,540 |
| CASH AND CASH EQUIVALENTS, end of period | $110,354 | $136,233 |

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Tabular dollar amounts, except per unit data, are in thousands)
(unaudited)

1. OPERATIONS AND ORGANIZATION:

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

Business Operations

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, New Mexico and West Virginia. Our intrastate transportation and storage operations primarily focus on transporting natural gas in Texas 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, Eagle Ford System, North Texas System and Northern Louisiana assets. ETC OLP also owns a 70% interest in Lone Star.
- 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, a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern's revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC FEP, a Delaware limited liability company that directly owns a 50% interest in the Fayetteville Express interstate natural gas pipeline.
- ETC Tiger, a Delaware limited liability company engaged in interstate transportation of natural gas.
- CrossCountry Energy, LLC, a Delaware limited liability company that indirectly owns a 50% interest in Citrus Corp., which owns 100% of the FGT interstate natural gas pipeline.
- ETC Compression, a Delaware limited liability company engaged in natural gas compression services and related equipment sales.

On January 12, 2012, we contributed HOLP and Titan, our subsidiaries that formerly operated our propane operations, to AmeriGas. See Note 6.

On October 5, 2012, we completed the Sunoco Merger and Holdco Transaction, as described below in Note 3.

Our historical financial statements reflect the following reportable business segments: intrastate natural gas transportation and storage; interstate natural gas transportation; midstream; NGL transportation and services; and retail propane and other retail propane related operations.

Preparation of Interim Financial Statements

The accompanying consolidated balance sheet as of December 31, 2011, which has been derived from audited financial statements, and the unaudited interim consolidated financial statements and notes thereto of the Partnership as of September 30, 2012 and for the three and nine month periods ended September 30, 2012 and 2011, have been prepared in accordance with GAAP for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all of 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.

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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 the Partnership as of September 30, 2012, and the Partnership's results of operations and cash flows for the three and nine months ended September 30, 2012 and 2011. The unaudited interim 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, 2011, as filed with the SEC on February 22, 2012.
Certain prior period amounts have been reclassified to conform to the 2012 presentation. These reclassifications had no impact on net income or total equity.

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 our natural gas and NGL related 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 estimated operating results 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, 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, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual values and results could differ from those estimates.

3. ACQUISITIONS AND DIVESTITURES:
Sunoco Merger
On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco, Inc. ("Sunoco"). Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 54,971,724 ETP Common Units and a total of approximately $2.6 billion in cash.
Sunoco generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco also owned a 2% general partner interest, 100% of the IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. As discussed below, on October 5, 2012, Sunoco's interests in Sunoco Logistics were transferred to the Partnership.
Sunoco Logistics is a publicly traded limited partnership that owns and operates a logistics business consisting of a geographically diverse portfolio of complementary pipeline, terminalling and crude oil acquisition and marketing assets. The refined products pipelines business consists of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in refined products pipelines. The crude oil pipeline business consists of crude oil pipelines located principally in Oklahoma and Texas. The terminal facilities business consists of refined products and crude oil terminal capacity at the Nederland Terminal on the Gulf Coast of Texas and capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey. The crude oil acquisition and marketing business, principally conducted in Oklahoma and Texas, involves the acquisition and marketing of crude oil and consists of crude oil transport trucks and crude oil truck unloading facilities.
ETP incurred merger related costs related to the Sunoco Merger of $5.7 million and $12.0 million for the three and nine months ended September 30, 2012, respectively.
Holdco Transaction

Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation ("Holdco"), an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and will retain a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90,706,000 Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a

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maximum cash distribution of $3.75 per Class F Unit per year, which is the current level. Pursuant to a stockholders agreement between ETE and ETP, ETP will control Holdco. Consequently, ETP will consolidate Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction. Under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The relinquishment will apply to the distribution to be paid with respect to the third quarter ended September 30, 2012.

Discontinued Operations

In October 2012, we sold ETC Canyon Pipeline, LLC ("Canyon") for approximately $207 million. For the three and nine months ended September 30, 2012, the results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been restated to present Canyon's operations as discontinued operations in the consolidated statements of operations. Canyon's assets and liabilities have been reclassified and reported as assets and liabilities held for sale as of September 30, 2012. A $145 million non-cash write-down of the carrying amounts of the Canyon assets to net recoverable value was recorded during the three months ended September 30, 2012.

4. CASH AND CASH EQUIVALENTS:

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.

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

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2012 | 2011 |
| Accounts receivable | $(112,276) | $28,318 |
| Accounts receivable from related companies | (68,828) | (22,917) |
| Inventories | (26,047) | 67,716 |
| Exchanges receivable | (578) | 6,300 |
| Other current assets | 73,228 | (25,956) |
| Other non-current assets, net | 5,088 | 7,061 |
| Accounts payable | 48,120 | (11,333) |
| Accounts payable to related companies | 85,943 | (804) |
| Exchanges payable | (3,909) | 231 |
| Accrued and other current liabilities | 42,561 | 78,997 |
| Other non-current liabilities | (5,362) | 1,298 |
| Price risk management assets and liabilities, net | 22,324 | 66,136 |
| Net change in operating assets and liabilities, net of effects of acquisitions and deconsolidation | $60,264 | $195,047 |

Non-cash investing and financing activities are as follows:

| | Nine Months Ended September 30, 2012 | 2011 |
|---|---|---|
| NON-CASH INVESTING ACTIVITIES: | | |
| Accrued capital expenditures | $383,426 | $128,874 |
| AmeriGas limited partner interests received in exchange for contribution of Propane Business (See Note 6) | $1,123,003 | $— |
| NON-CASH FINANCING ACTIVITIES: | | |
| Contributions receivable related to noncontrolling interest | $13,180 | $— |
| Issuance of common units in connection with acquisitions | $112,000 | $3,000 |
| Long-term debt assumed and non-compete agreement notes payable issued in acquisitions | $— | $4,166 |

5. INVENTORIES:

Inventories consisted of the following:

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Natural gas and NGLs, excluding propane | $151,387 | $144,251 |
| Propane | — | 86,958 |
| Appliances, parts and fittings and other | 82,816 | 75,531 |
| Total inventories | $234,203 | $306,740 |

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

6. INVESTMENTS IN UNCONSOLIDATED AFFILIATES:

Citrus Merger

On March 26, 2012, ETE consummated the acquisition of Southern Union and, concurrently with the closing of the Southern Union acquisition, CrossCountry Energy, LLC ("CrossCountry"), a subsidiary of Southern Union that indirectly owned a 50% interest in Citrus Corp. ("Citrus"), merged with a subsidiary of ETP and, in connection therewith, ETP paid approximately $1.9 billion in cash and issued $105.0 million of ETP Common Units (the "Citrus Merger") to a subsidiary of ETE. As a result of the consummation of the Citrus Merger, ETP owns CrossCountry, which in turn owns a 50% interest in Citrus. The other 50% interest in Citrus is owned by a subsidiary of Kinder Morgan, Inc.

Citrus owns 100% of FGT, a natural gas pipeline system that originates in Texas and delivers natural gas to the Florida peninsula.

We recorded our investment in Citrus at $2.0 billion, which exceeded our proportionate share of Citrus' equity by $1.03 billion, all of which is treated as equity method goodwill due to the application of regulatory accounting.

Propane Operations

On January 12, 2012, we contributed our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") to AmeriGas. We received approximately $1.46 billion in cash and approximately 29.6 million AmeriGas Common Units valued at $1.12 billion at the time of the contribution. In addition, AmeriGas assumed approximately $71.0 million of existing HOLP debt. We recognized a gain on deconsolidation of $1.06 billion as a result of this transaction. The cash proceeds were used to complete our tender offer of existing debt (see Note 10) in January 2012 and to repay borrowings on our revolving credit facility.

Our investment in AmeriGas reflected $630.0 million in excess of our proportionate share of AmeriGas' limited partners' capital. Of this excess fair value, $288.6 million is being amortized over a weighted average period of 14 years, and $341.4 million is being treated as equity method goodwill and non-amortizable intangible assets.

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In connection with the closing of this transaction, we entered into a support agreement with AmeriGas (See Note 14). Under a unitholder agreement with AmeriGas, we are also obligated to hold the approximately 29.6 million AmeriGas Common Units that we received in this transaction until January 2013.

We have not reflected our Propane Business as discontinued operations as a result of our investment in AmeriGas.

In June 2012, we sold the remainder of our retail propane operations, consisting of our cylinder exchange business, to a third party. In connection with the contribution agreement with AmeriGas, certain excess sales proceeds from the sale of the cylinder exchange business were remitted to AmeriGas, and we received net proceeds of approximately $43.0 million.

## 7. GOODWILL AND INTANGIBLE ASSETS:

A net decrease in goodwill of $619.4 million was recorded during the nine months ended September 30, 2012 primarily due to the contribution of our Propane Business to AmeriGas. See Note 6.

Components and useful lives of intangible assets were as follows:

| | September 30, 2012 | | December 31, 2011 | |
|---|---|---|---|---|
| | Gross Carrying Amount | Accumulated Amortization | Gross Carrying Amount | Accumulated Amortization |
| Amortizable intangible assets: | | | | |
| Customer relationships, contracts and agreements (3 to 46 years) | $219,825 | $(59,162) | $338,424 | $(95,239) |
| Noncompete agreements | — | — | 15,431 | (7,835) |
| Patents (9 years) | 750 | (264) | 750 | (201) |
| Other (10 to 15 years) | 843 | (145) | 1,320 | (580) |
| Total amortizable intangible assets | 221,418 | (59,571) | 355,925 | (103,855) |
| Non-amortizable intangible assets: | | | | |
| Trademarks | — | — | 79,339 | — |
| Total intangible assets | $221,418 | $(59,571) | $435,264 | $(103,855) |

Aggregate amortization expense of intangible assets was as follows:

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Reported in depreciation and amortization | $3,664 | $7,267 | $12,129 | $17,683 |

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

| | |
|---|---|
| 2012 (remainder) | $3,523 |
| 2013 | 11,271 |
| 2014 | 10,146 |
| 2015 | 10,146 |
| 2016 | 10,146 |

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 goodwill and non-amortizable intangible assets for impairment annually, or more frequently if circumstances dictate. Our annual impairment test is performed as of August 31 for reporting units within our intrastate transportation and storage and midstream segments and as of December 31 for all other segments. We have not completed our annual impairment tests for 2012 and have not recorded any impairments related to amortizable intangible assets during the nine months ended September 30, 2012.

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8. 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.

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 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 as the primary input, the LIBOR curve, is 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. During the period ended September 30, 2012, no transfers were made between any levels within the fair value hierarchy.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value of our consolidated debt obligations at September 30, 2012 and December 31, 2011 was $10.23 billion and $8.39 billion, respectively. As of September 30, 2012 and December 31, 2011, the aggregate carrying amount of our consolidated debt obligations was $9.04 billion and $7.81 billion, respectively. The fair value of our consolidated debt obligations is a Level 2 valuation based on the observable inputs used for similar liabilities.

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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 September 30, 2012 and December 31, 2011 based on inputs used to derive their fair values:

| | Fair Value Total | Fair Value Measurements at September 30, 2012 | |
|---|---|---|---|
| | | Level 1 | Level 2 |
| Financial Assets: | | | |
| Marketable securities (included in other current assets) | $6 | $6 | $— |
| Interest rate derivatives | 54,479 | — | 54,479 |
| Commodity derivatives: | | | |
| Natural Gas: | | | |
| Basis Swaps IFERC/NYMEX | 30,102 | 30,102 | — |
| Swing Swaps IFERC | 14,260 | 172 | 14,088 |
| Fixed Swaps/Futures | 84,383 | 84,383 | — |
| Options — Puts | 2,322 | — | 2,322 |
| Options — Calls | 1,790 | — | 1,790 |
| Forward Physical Contracts | 2,223 | — | 2,223 |
| Power: | | | |
| Forwards | 6,176 | — | 6,176 |
| Futures | 374 | 374 | — |
| Options — Calls | 2,495 | — | 2,495 |
| Total commodity derivatives | 144,125 | 115,031 | 29,094 |
| Total | $198,610 | $115,037 | $83,573 |
| Financial Liabilities: | | | |
| Interest rate derivatives | $(150,220) | $— | $(150,220) |
| Commodity derivatives: | | | |
| Natural Gas: | | | |
| Basis Swaps IFERC/NYMEX | (42,492) | (42,492) | — |
| Swing Swaps IFERC | (14,918) | (648) | (14,270) |
| Fixed Swaps/Futures | (104,316) | (104,316) | — |
| Options — Puts | (672) | — | (672) |
| Options — Calls | (2,134) | — | (2,134) |
| Forward Physical Contracts | (2,082) | — | (2,082) |
| Power: | | | |
| Forwards | (5,865) | — | (5,865) |
| Futures | (605) | (605) | — |
| Options — Calls | (2,106) | — | (2,106) |
| Total commodity derivatives | (175,190) | (148,061) | (27,129) |
| Total | $(325,410) | $(148,061) | $(177,349) |

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| | Fair Value Total | Fair Value Measurements at December 31, 2011 | |
|---|---|---|---|
| | | Level 1 | Level 2 |
| Financial Assets: | | | |
| Marketable securities (included in other current assets) | $1,229 | $1,229 | $— |
| Interest rate derivatives | 36,301 | — | 36,301 |
| Commodity derivatives: | | | |
| Natural Gas: | | | |
| Basis Swaps IFERC/NYMEX | 62,924 | 62,924 | — |
| Swing Swaps IFERC | 15,002 | 1,687 | 13,315 |
| Fixed Swaps/Futures | 214,572 | 214,572 | — |
| Options — Puts | 6,435 | — | 6,435 |
| Forward Physical Contracts | 699 | — | 699 |
| Propane – Forwards/Swaps | 9 | — | 9 |
| Total commodity derivatives | 299,641 | 279,183 | 20,458 |
| Total | $337,171 | $280,412 | $56,759 |
| Financial Liabilities: | | | |
| Interest rate derivatives | $(117,020) | $— | $(117,020) |
| Commodity derivatives: | | | |
| Natural Gas: | | | |
| Basis Swaps IFERC/NYMEX | (82,290) | (82,290) | — |
| Swing Swaps IFERC | (16,074) | (3,061) | (13,013) |
| Fixed Swaps/Futures | (148,111) | (148,111) | — |
| Options — Calls | (12) | — | (12) |
| Forward Physical Contracts | (712) | — | (712) |
| Propane – Forwards/Swaps | (4,131) | — | (4,131) |
| Total commodity derivatives | (251,330) | (233,462) | (17,868) |
| Total | $(368,350) | $(233,462) | $(134,888) |

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## 9. NET INCOME PER LIMITED PARTNER UNIT:

Our net income for partners' capital and statements of operations presentation purposes is allocated to ETP GP and Limited Partners in accordance with their respective partnership percentages, after giving effect to priority income allocations for incentive distributions, if any, to ETP GP, the holder of the 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 ETP GP and Limited Partners based on their respective ownership interests.

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Income from continuing operations | $193,371 | $77,593 | $1,446,155 | $484,390 |
| Less: Income from continuing operations attributable noncontrolling interest | 9,184 | 9,285 | 32,914 | 17,673 |
| Income from continuing operations, net of noncontrolling interest | 184,187 | 68,308 | 1,413,241 | 466,717 |
| General Partner's interest in income from continuing operations | 118,664 | 104,835 | 344,148 | 318,317 |
| Limited Partners' interest in income (loss) from continuing operations | 65,523 | (36,527) | 1,069,093 | 148,400 |
| Additional earnings allocated from (to) General Partner | 622 | 9 | 1,116 | 572 |
| Distributions on employee unit awards, net of allocation to General Partner | (1,941) | (1,894) | (9,275) | (5,619) |
| Income (loss) from continuing operations available to Limited Partners | $64,204 | $(38,412) | $1,060,934 | $143,353 |
| Weighted average Limited Partner units — basic | 245,139,324 | 209,151,808 | 233,798,902 | 203,918,940 |
| Basic income (loss) from continuing operations per Limited Partner unit | $0.26 | $(0.18) | $4.54 | $0.70 |
| Dilutive effect of unvested Unit Awards | 1,156,952 | — | 1,204,791 | 1,166,830 |
| Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards | 246,296,276 | 209,151,808 | 235,003,693 | 205,085,770 |
| Diluted income (loss) from continuing operations per Limited Partner unit | $0.26 | $(0.18) | $4.52 | $0.70 |
| Basic income (loss) from discontinued operations per Limited Partner unit | $(0.59) | $(0.01) | $(0.63) | $(0.02) |
| Diluted income (loss) from discontinued operations per Limited Partner unit | $(0.59) | $(0.01) | $(0.63) | $(0.02) |

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended September 30, 2012 are expected to be $392.7 million in total, which exceeds net income for the period by $355.7 million. Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended September 30, 2011 were $295.9 million in total, which exceeded net income for the period by $229.2 million. The allocation of the distributions in excess of net income is based on the proportionate ownership interests of the Limited Partners and General Partner. Based on this allocation approach, the distributions paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended September 30, 2012 and 2011, and as a result, net losses were allocated to the Limited Partners for the period.

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10. DEBT OBLIGATIONS:

Our debt obligations consist of the following:

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| ETP Credit Facility | $491,914 | $314,438 |
| ETP Senior Notes | 7,691,951 | 6,550,000 |
| Transwestern Senior Notes | 870,000 | 870,000 |
| HOLP Senior Notes | — | 71,314 |
| Other long-term debt | — | 10,345 |
| Unamortized discounts | (20,563) | (15,457) |
| Fair value adjustments related to interest rate swaps | 7,438 | 11,647 |
| Total debt | 9,040,740 | 7,812,287 |
| Less: current maturities | (350,000) | (424,117) |
| Long-term debt, less current maturities | $8,690,740 | $7,388,170 |

The following table reflects future maturities of long-term debt for each of the next five years and thereafter. These amounts exclude $13.1 million in unamortized discounts and fair value adjustments related to interest rate swaps:

| | |
|---|---|
| 2012 (remainder) | $— |
| 2013 | 350,000 |
| 2014 | 379,947 |
| 2015 | 750,000 |
| 2016 | 616,914 |
| Thereafter | 6,957,004 |
| Total | $9,053,865 |

Senior Notes

In January 2012, we completed a public offering of $1.00 billion aggregate principal amount of 5.20% Senior Notes due February 1, 2022 and $1.00 billion aggregate principal amount of 6.50% Senior Notes due February 1, 2042 and used the net proceeds of $1.98 billion from the offering to fund the cash portion of the purchase price of the Citrus Merger and for general partnership purposes. We may redeem some or all of the notes at any time and from time to time pursuant to the terms of the indenture subject to the payment of a "make-whole" premium. Interest will be paid semi-annually.

In January 2012, we announced a tender offer for approximately $750.0 million aggregate principal amount of specified series of the ETP Senior Notes. The tender offer consisted of two separate offers: an Any and All Offer and a Maximum Tender Offer. The senior notes described below were repurchased under the offers for a total cost of $885.9 million and a loss on extinguishment of debt of $115.0 million was recorded during the nine months ended September 30, 2012.

In the Any and All Offer, we offered to purchase any and all of our 5.65% Senior Notes due August 1, 2012, at a fixed price. Pursuant to the Any and All Offer, we purchased $292.0 million aggregate principal amount of our 5.65% Senior Notes due August 1, 2012.

In the Maximum Tender Offer, we offered to purchase certain series of outstanding ETP Senior Notes at a fixed spread over the index rate. Pursuant to the Maximum Tender Offer, on February 7, 2012, we purchased $200.0 million aggregate principal amount of our 9.7% Senior Notes due March 15, 2019, $200.0 million aggregate principal amount of our 9.0% Senior Notes due April 15, 2019, and $58.1 million aggregate principal amount of our 8.5% Senior Notes due April 15, 2014.

Credit Facility

The indebtedness under ETP's credit facility (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.

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As of September 30, 2012, we had $491.9 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.98 billion after taking into account letters of credit of $31.9 million. The weighted average interest rate on the total amount outstanding as of September 30, 2012 was 1.72%.

ETP used approximately $2.0 billion of Sunoco's cash on hand to partially fund the cash portion of the Sunoco Merger consideration. The remainder of the cash portion of the merger consideration, approximately $620 million, was funded with borrowings under the ETP Credit Facility.

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, which was completed on October 5, 2012, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco's existing senior notes and debentures.

Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements at September 30, 2012.

## 11. EQUITY:

Common Units Issued

The change in Common Units during the nine months ended September 30, 2012 was as follows:

| | Number of Units |
|---|---|
| Outstanding at December 31, 2011 | 225,468,108 |
| Common Units issued in connection with public offerings | 15,525,000 |
| Common Units issued in connection with the Equity Distribution Agreement | 1,600,483 |
| Common Units issued in connection with the Distribution Reinvestment Plan | 548,708 |
| Common Units issued in connection with acquisitions | 2,404,062 |
| Common Units issued under equity incentive plans | 15,200 |
| Outstanding at September 30, 2012 | 245,561,561 |

During the nine months ended September 30, 2012, we received proceeds from units issued pursuant to an Equity Distribution Agreement with Credit Suisse Securities (USA) LLC of $76.7 million, net of commissions, which proceeds were used for general partnership purposes. As of September 30, 2012, no Common Units remain available to be issued under this agreement.

On July 3, 2012, we issued 15,525,000 Common Units representing limited partner interests at $44.57 per Common Unit in a public offering. Net proceeds of approximately $671.1 million from the offering were used to repay amounts outstanding under the ETP Credit Facility, to fund capital expenditures related to pipeline construction projects and for general partnership purposes.

We also have a Distribution Reinvestment Plan (the "DRIP") which provides Unitholders of record and beneficial owners of our Common Units a voluntary means by which they can increase the number of ETP Common Units they own by reinvesting the quarterly cash distributions they would otherwise receive in the purchase of additional Common Units. The registration statement we filed in connection with the DRIP covers the issuance of up to 5,750,000 Common Units under the DRIP. For the nine months ended September 30, 2012, distributions of approximately $23.9 million were reinvested under the DRIP resulting in the issuance of 548,708 Common Units. As of September 30, 2012, a total of 4,847,613 Common Units remain available to be issued under this registration statement.

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Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by us subsequent to December 31, 2011:

| Quarter Ended | Record Date | Payment Date | Rate |
|---|---|---|---|
| December 31, 2011 | February 7, 2012 | February 14, 2012 | $0.89375 |
| March 31, 2012 | May 4, 2012 | May 15, 2012 | 0.89375 |
| June 30, 2012 | August 6, 2012 | August 14, 2012 | 0.89375 |
| September 30, 2012 | November 6, 2012 | November 14, 2012 | 0.89375 |

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters beginning with the distribution paid on May 15, 2012. In conjunction with the Holdco Transaction, ETE agreed to relinquish its right to $210 million of incentive distributions from ETP that ETE would otherwise be entitled to receive over 12 consecutive quarters beginning with the distribution paid on November 14, 2012.

AOCI

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

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Net gains on commodity related hedges | $3,327 | $6,455 |
| Unrealized gains on available-for-sale securities | — | 114 |
| Equity investments, net | (13,678) | — |
| Total AOCI, net of tax | $(10,351) | $6,569 |

12. UNIT-BASED COMPENSATION PLANS:

During the nine months ended September 30, 2012, employees were granted a total of 83,167 unvested awards with five-year service vesting requirements, and directors were granted a total of 6,760 unvested awards with three-year service vesting requirements. The weighted average grant-date fair value of these awards was $46.64 per unit. As of September 30, 2012 a total of 2,325,945 unit awards remain unvested, including the new awards granted during the period. We expect to recognize a total of $51.4 million in compensation expense over a weighted average period of 1.7 years related to unvested awards.

13. INCOME TAXES:

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Current expense (benefit): | | | | |
| Federal | $(9,140) | $1,125 | $(9,200) | $6,788 |
| State | 2,345 | 2,510 | 9,287 | 11,635 |
| Total | (6,795) | 3,635 | 87 | 18,423 |
| Deferred expense (benefit): | | | | |
| Federal | 7,742 | 872 | 9,033 | 1,876 |
| State | (179) | (468) | 5,795 | 118 |
| Total | 7,563 | 404 | 14,828 | 1,994 |
| Total income tax expense | $768 | $4,039 | $14,915 | $20,417 |

The effective tax rate differs from the statutory rate primarily due to Partnership earnings that are not subject to federal and state income taxes at the Partnership level. We expect our effective tax rate to increase as a result of the Sunoco Merger and Holdco Transaction, since Sunoco and Southern Union are corporations and are subject to federal and state income taxes.

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

Contingent Matters Potentially Impacting the Partnership from Our Investment in Citrus

Florida Gas Pipeline Relocation Costs. The Florida Department of Transportation, Florida's Turnpike Enterprise ("FDOT/FTE") has various turnpike/State Road 91 widening projects that have impacted or may, over time, impact one or more of FGTs' mainline pipelines located in FDOT/FTE rights-of-way. Several FDOT/FTE projects are the subject of litigation in Broward County, Florida. On January 27, 2011, a jury awarded FGT $82.7 million and rejected all damage claims by the FDOT/FTE. On May 2, 2011, the judge issued an order entitling FGT to an easement of 15 feet on either side of its pipelines and 75 feet of temporary work space. The judge further ruled that FGT is entitled to approximately $8.0 million in interest. In addition to ruling on other aspects of the easement, he ruled that pavement could not be placed directly over FGTs' pipeline without the consent of FGT, although FGT would be required to relocate the pipeline if it did not provide such consent. While FGT would seek reimbursement of any costs associated with relocation of its pipeline in connection with an FDOT project, FGT may not be successful in obtaining such reimbursement and, as such, could be required to bear the cost of such relocation. In any such instance, FGT would seek recovery of the reimbursement costs in rates. The judge also denied all other pending post-trial motions. The FDOT/FTE filed a notice of appeal on July 12, 2011. On June 6, 2012, Florida's Fourth District Court of Appeal (“4th DCA”) issued an opinion affirming the jury award of damages and also affirming or remanding for further consideration by the trial court certain other determinations with respect to FGT's easement rights and FDOT/FTE's obligations regarding future FDOT/FTE projects. In particular, the 4th DCA affirmed that FDOT/FTE could not pave directly over our pipeline without FGTs' consent and remanded and directed the trial court to make reference in the final judgment to FDOT/FTE's obligation to seek reasonable alternatives to relocation. In addition, the 4th DCA overturned the portion of the trial court judgment defining the width of Florida Gas's easements as 15 feet on either side of its pipelines and defining the temporary work space available to Florida Gas under its easements as 75 feet in width, stating that the width of such easements and temporary work space should be determined on a case by case basis dependent on the needs of each particular relocation and whether a road improvement is a material interference with the easement. Reimbursement for any future relocation expenses will also be determined on a case by case basis. FGT has filed a petition requesting the Supreme Court of Florida to exercise its discretionary jurisdiction and to reverse the portion of the 4th DCA decision overturning the trial court judgment specifically defining the width of FGTs' easements and temporary work space. The Supreme Court of Florida has not yet decided whether to hear the case. Amounts ultimately received would primarily reduce FGTs' property, plant and equipment costs.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550.0 million in aggregate principal amount of 6.75% Senior Notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% Senior Notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the contribution of the Propane Business, ETP entered into a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt as defined in the CRSA.

Interstate Natural Gas Pipeline Regulation

Under the Natural Gas Act, interstate natural gas companies must charge rates that are just and reasonable. In addition, the NGA prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service. On December 21, 2010, an Administrative Law Judge certified a contested offer of settlement relating to FGT's rates and terms and conditions of service. On January 10, 2011, the contesting party withdrew its opposition to the settlement. On February 24, 2011, the FERC issued an order approving the settlement, which order settled a number of issues related to FGT's rates and terms and conditions of service. Among other matters, FGT is required to make its next NGA section 4 general rate case filing no later than November 1, 2014.

Commitments

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and we enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. 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 2029. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.6 million and $5.5 million for the three months ended

September 30, 2012 and 2011, respectively. For the nine months ended September 30, 2012 and 2011, rental expense for operating leases totaled approximately \$16.8 million and \$15.7 million, respectively.

Our joint venture agreements require that we fund our proportionate share of capital contributions to our unconsolidated affiliates. Such contributions will depend upon our unconsolidated affiliates' capital requirements, such as for funding capital projects or repayment of long-term obligations.

Sunoco Litigation

Following the announcement of the Sunoco Merger on April 30, 2012, eight putative class action and derivative complaints were filed in connection with the Sunoco Merger in the Court of Common Pleas of Philadelphia County, Pennsylvania. Each complaint names as defendants the members of Sunoco's board of directors and alleges that they breached their fiduciary duties by negotiating and executing, through an unfair and conflicted process, a merger agreement that provides inadequate consideration and that contains impermissible terms designed to deter alternative bids. Each complaint also names as defendants Sunoco, ETP, ETP GP, ETP LLC, and Sam Acquisition Corporation, alleging that they aided and abetted the breach of fiduciary duties by Sunoco's directors; some of the complaints also name ETE as a defendant on those aiding and abetting claims. In September 2012, all of these lawsuits were settled with no payment obligation on the part of any of the defendants following the filing of Current Reports on Form 8-K that included additional disclosures that were incorporated by reference into the proxy statement related to the Sunoco Merger. It is anticipated that the plaintiffs' attorneys will seek compensation for attorneys' fees related to their efforts in obtaining these additional disclosures; we currently are not able to estimate how much these fees will be.

Other Litigation and Contingencies

In November, 2011, a derivative lawsuit captioned W. J. Garrett Trust v. Bill W. Byrne, et al., Cause No. 2011-71702, was filed in the 234th Judicial District Court of Harris County, Texas. The petition stated that it was filed on behalf of ETP. ETP was also named as a nominal defendant. The petition also named as defendants ETP GP, ETP LLC, the Boards of Directors of ETP LLC (collectively with ETP GP, and ETP LLC, the "ETP Defendants"), ETE, and Southern Union. In October 2012, the plaintiff and two new unitholder plaintiffs filed their Third Amended Petition, naming these same defendants and adding Royal Bank of Scotland, PLC, RBS Securities, Inc. ("RBS"), and four members of ETP management ("Management Defendants") as defendants. In their third amended petition, the plaintiffs allege that the ETP Defendants breached their fiduciary and contractual duties in connection with the Citrus Merger and ETP's contribution of its Propane Business to AmeriGas (the "AmeriGas Transaction"). The third amended petition alleges that the Citrus Merger, among other things, involves an unfair price and an unfair process and that the ETP Defendants failed to adequately evaluate the transaction. The third amended petition also alleges that the ETP Defendants failed to, among other things, adequately evaluate the AmeriGas Transaction. The third amended petition alleges that these defendants entered into both transactions primarily to assist in ETE's consummation of its merger with Southern Union and thereby primarily to benefit themselves personally. The third amended petition further alleges that RBS committed malpractice in issuing fairness opinions and that the Management Defendants failed to disclose material information regarding RBS' relationship with ETE. The third amended petition asserts claims for breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith against each of the ETP Defendants and Management Defendants. The third amended petition asserts claims against ETE and Southern Union for aiding and abetting the breaches of fiduciary duty, breaches of contractual duties, and acts of bad faith, as well as tortious interference with contract. The third amended petition also asserts claims for declaratory judgment and conspiracy against all defendants. The lawsuit seeks, among other things, the following relief: (i) a declaration that the lawsuit is properly maintainable as a derivative action; (ii) a declaration that the Citrus Merger and AmeriGas Transaction were unlawful and unenforceable because they involved breaches of fiduciary and contractual duties; (iii) a declaration that ETE and Southern Union aided and abetted the alleged breaches of fiduciary and contractual duties; (iv) a declaration that defendants conspired to breach, aided and abetted, and did breach fiduciary and contractual duties; (v) an order directing the ETP Defendants and Management Defendants to exercise their fiduciary duties to obtain a transaction or transactions in the best interest of ETP's unitholders; (vi) damages; and (vii) attorneys' and other fees and costs.

In March 2012, this action was transferred to the 157th Judicial District Court of Harris County, Texas. In October 2012, the defendants filed a motion for summary judgment; the court has not yet ruled on the motion. Trial in this action is not currently set.

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 NGLs are flammable and combustible. 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.

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 and can be estimated we accrue the contingent obligation as well as any expected insurance recoverable amounts related to the contingency. As of December 31, 2011, accruals of approximately $18.2 million were reflected on our balance sheet related to these contingent obligations. As of September 30, 2012 there were no accruals reflected on our balance sheet related to contingent obligations, as all contingent obligations were related to our Propane Business which was contributed to AmeriGas in January 2012 (see Note 6). 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 there can be no assurance that the outcome of a particular matter will not result in the payment of amounts that have not been accrued for the matter. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

No amounts have been recorded in our September 30, 2012 or December 31, 2011 consolidated balance sheets for contingencies and current litigation, other than amounts disclosed herein.

Environmental Matters

Our operations are subject to extensive federal, state and local environmental and safety laws and regulations that 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 business of transporting, storing, gathering, treating, compressing, blending and processing natural gas, natural gas liquids and other products. 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.

We are unable to estimate any losses or range of losses that could result from such developments. Furthermore, we may revise accrual amounts prior to resolution of a particular contingency based on changes in facts and circumstances or changes in the expected outcome.

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 September 30, 2012 and December 31, 2011, accruals on an undiscounted basis of $8.6 million and $13.7 million, respectively, were recorded in our consolidated balance sheets as accrued and other current liabilities and other non-current liabilities related to environmental matters.

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 cleanup costs.
Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the cleanup activities include remediation of several compressor sites on the Transwestern system for contamination by PCBs. 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

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2025 is $5.0 million, which is included in the aggregate environmental accruals discussed above. Transwestern received approval from the FERC for the continuation of rate recovery of projected soil and groundwater remediation costs not related to PCBs for the term of its rate case settlement.

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 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.

The EPA Spill Prevention, Control and Countermeasures program regulations were recently modified and impose additional requirements on many of our facilities. We expect to expend resources on tank integrity testing and any associated corrective actions as well as potential upgrades to containment structures to comply with the new rules. 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.

On August 20, 2010, the EPA published new regulations under the federal CAA to control emissions of hazardous air pollutants from existing stationary reciprocal internal combustion engines. The rule will require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment. In response to an industry group legal challenge to portions of the rule in the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA, on March 9, 2011, the EPA issued a new proposed rule and direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. If no further changes to the standard are made as a result of comments to the proposed rule, we would not expect that the cost to comply with the rule’s requirements will have a material adverse effect on our financial condition or results of operations. Compliance with the final rule is required by October 2013.

On June 29, 2011, the EPA finalized a rule under the CAA that revised the new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. The rule became effective on August 29, 2011. The rule modifications may require us to undertake significant expenditures, including expenditures for purchasing, installing, monitoring and maintaining emissions control equipment, if equipment is replaced or existing facilities are expanded in the future. At this point, we are not able to predict the cost to comply with the rule’s requirements, because the rule applies only to changes we might make in the future, but we would not expect that the cost to comply with the rule's requirements will have a material adverse effect on our financial condition or results of operations.

On April 17, 2012, the EPA issued the final Oil and Natural Gas Sector New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants. The standards revise the new source performance standards for volatile organic compounds from leaking components at onshore natural gas processing plants and new source performance standards for sulfur dioxide emissions from natural gas processing plants. The EPA also established standards for certain oil and gas operations not covered by the existing standards. In addition to the operations covered by the existing standards, the newly established standards regulate volatile organic compound emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels. In general, the revised New Source Performance Standards will apply only to sources that are newly constructed or substantially modified or reconstructed in the future, while the revised National Emission Standards for Hazardous Air Pollutants will not require most sources to which they apply to be in compliance until 2015. ETP is reviewing the new standards to determine the impact on its operations.

Our pipeline operations are subject to regulation by the DOT under the 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 September 30, 2012 and 2011, $0.8 million and $4.2 million, respectively, of capital costs and $3.9 million and $3.9 million, respectively, of operating and maintenance costs have been incurred for pipeline integrity testing. For the nine months ended September 30, 2012 and 2011, $5.4 million and $9.7 million, respectively, of capital costs and $9.9 million and $9.8 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 future capital and operating expenditures for repairs or upgrades deemed necessary to

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ensure the continued safe and reliable operation of our pipelines; however, no estimate can be made at this time of the likely range of such expenditures.

Our operations are also subject to the requirements of the 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.

## 15. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

### Commodity Price Risk

We are exposed to market risks related to the volatility of commodity 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.

We inject and hold natural gas in our Bammel storage facility to take advantage of contango markets (i.e., 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 into 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 adjustments or the physical withdrawal of natural gas.

We are also exposed to market risk on natural 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. Certain contracts that qualify for hedge accounting are designated as cash flow hedges of the forecasted sale of natural gas. The change in value, to the extent the contracts are effective, remains in AOCI 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.

Our trading activities include the use of financial commodity derivatives to take advantage of market opportunities. These trading activities are a complement to our transportation and storage segment's operations and are netted in cost of products sold in our consolidated statements of operations. Additionally, we also have trading activities related to power in our “All Other” segment which are also netted in cost of products sold. As a result of our trading activities and the use of derivative financial instruments in our transportation and storage segment, 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 our risk oversight committee, which includes members of senior management, and the limits and authorizations set forth in our commodity risk management policy.

Derivatives are utilized in our midstream segment in order to mitigate price volatility and manage fixed price exposure incurred from contractual obligations. We attempt to maintain balanced positions in our marketing activities to protect against 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. To the extent that financial contracts are not tied to physical delivery volumes, we may engage in offsetting 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.

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Prior to the deconsolidation of the Propane Business, we also used propane futures contracts to fix the purchase price related to certain fixed price sales contracts. Prior to the sale of our cylinder exchange business, we used propane futures contracts to secure the purchase price of our propane inventory for a percentage of the anticipated sales.

The following table details our outstanding commodity-related derivatives:

| | September 30, 2012 | | December 31, 2011 | |
|---|---|---|---|---|
| | Notional Volume | Maturity | Notional Volume | Maturity |
| Mark-to-Market Derivatives | | | | |
| (Trading) | | | | |
| Natural Gas (MMBtu): | | | | |
| Basis Swaps IFERC/NYMEX [1] | (29,850,000) | 2012-2013 | (151,260,000) | 2012-2013 |
| Power (Megawatt): | | | | |
| Forwards | 230,000 | 2012-2013 | — | — |
| Futures | (14,500) | 2012 | — | — |
| Options — Calls | 1,535,600 | 2012-2013 | — | — |
| (Non-Trading) | | | | |
| Natural Gas (MMBtu): | | | | |
| Basis Swaps IFERC/NYMEX | (8,057,500) | 2012-2013 | (61,420,000) | 2012-2013 |
| Swing Swaps IFERC | (18,827,500) | 2012-2013 | 92,370,000 | 2012-2013 |
| Fixed Swaps/Futures | (2,992,500) | 2012-2014 | 797,500 | 2012 |
| Forward Physical Contracts | (7,505,500) | 2012-2013 | (10,672,028) | 2012 |
| Propane (Gallons): | | | | |
| Forwards/Swaps | — | — | 38,766,000 | 2012-2013 |
| Fair Value Hedging Derivatives | | | | |
| (Non-Trading) | | | | |
| Natural Gas (MMBtu): | | | | |
| Basis Swaps IFERC/NYMEX | (20,670,000) | 2012-2013 | (28,752,500) | 2012 |
| Fixed Swaps/Futures | (46,752,500) | 2012-2013 | (45,822,500) | 2012 |
| Hedged Item — Inventory | 46,752,500 | 2012-2013 | 45,822,500 | 2012 |
| Cash Flow Hedging Derivatives | | | | |
| (Non-Trading) | | | | |
| Natural Gas (MMBtu): | | | | |
| Basis Swaps IFERC/NYMEX | (4,600,000) | 2012-2013 | — | — |
| Fixed Swaps/Futures | (11,900,000) | 2012-2013 | — | — |
| Options — Puts | 900,000 | 2012 | 3,600,000 | 2012 |
| Options — Calls | (900,000) | 2012 | (3,600,000) | 2012 |

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

We expect gains of $4.1 million related to commodity derivatives to be reclassified into earnings over the next 12 months 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. To maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We also manage our interest rate exposure by utilizing interest rate swaps to achieve a desired mix of fixed and variable rate debt. We also utilize forward starting interest rate swaps to lock in the rate on a portion of our anticipated debt issuances.

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We had the following interest rate swaps outstanding as of September 30, 2012 and December 31, 2011, none of which were designated as hedges for accounting purposes:

| Term | Type [1] | Notional Amount Outstanding September 30, 2012 | Notional Amount Outstanding December 31, 2011 |
|---|---|---|---|
| May 2012[2] | Forward starting to pay a fixed rate of 2.59% and receive a floating rate | $— | $350,000 |
| August 2012[2] | Forward starting to pay a fixed rate of 3.51% and receive a floating rate | — | 500,000 |
| July 2013[2] | Forward starting to pay a fixed rate of 4.02% and receive a floating rate | 400,000 | 300,000 |
| July 2014[2] | Forward starting to pay a fixed rate of 4.26% and receive a floating rate | 400,000 | — |
| July 2018 | Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70% | 600,000 | 500,000 |

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

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 or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers and power generation companies. This concentration of counterparties may impact our 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. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

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 consolidated balance sheets. The Partnership had net deposits with counterparties of $38.0 million and $66.2 million as of September 30, 2012 and December 31, 2011, respectively.

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.

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Derivative Summary

The following table provides an overview of the Partnership's derivative assets and liabilities as of September 30, 2012 and December 31, 2011:

| | Fair Value of Derivative Instruments | | | |
|---|---|---|---|---|
| | Asset Derivatives | | Liability Derivatives | |
| | September 30, 2012 | December 31, 2011 | September 30, 2012 | December 31, 2011 |
| Derivatives designated as hedging instruments: | | | | |
| Commodity derivatives (margin deposits) | $5,529 | $77,197 | $(16,209) | $(819) |
| Derivatives not designated as hedging instruments: | | | | |
| Commodity derivatives (margin deposits) | 135,448 | 227,337 | (156,673) | (251,268) |
| Commodity derivatives | 10,895 | 708 | (10,053) | (4,844) |
| Interest rate derivatives | 54,479 | 36,301 | (150,220) | (117,020) |
| | 200,822 | 264,346 | (316,946) | (373,132) |
| Total derivatives | $206,351 | $341,543 | $(333,155) | $(373,951) |

The commodity derivatives (margin deposits) are recorded in "Other current assets" on our consolidated balance sheets. The remainder of the derivatives are recorded in "Price risk management assets/liabilities." In addition to the above derivatives, "Price risk management liabilities" as of September 30, 2012 included approximately $6.6 million of option premiums that are being amortized through 2013.

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.

The following tables summarize the amounts recognized with respect to our derivative financial instruments for the periods presented:

| | Change in Value Recognized in OCI on Derivatives (Effective Portion) | | | |
|---|---|---|---|---|
| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| | 2012 | 2011 | 2012 | 2011 |
| Derivatives in cash flow hedging relationships: | | | | |
| Commodity derivatives | $(3,430) | $6,127 | $10,465 | $14,470 |

| | 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 September 30, | | Nine Months Ended September 30, | |
| | | 2012 | 2011 | 2012 | 2011 |
| Derivatives in cash flow hedging relationships: | | | | | |
| Commodity derivatives | Cost of products sold | $3,601 | $5,116 | $13,652 | $27,069 |

| | Location of Gain/(Loss) Reclassified from AOCI into Income (Ineffective Portion) | Amount of Gain/(Loss) Recognized in Income on Ineffective Portion |
|---|---|---|

| | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|---|
| | | 2012 | 2011 | 2012 | 2011 |
| Derivatives in cash flow hedging relationships: | | | | | |
| Commodity derivatives | Cost of products sold | $(63) | $(112) | $(17) | $351 |

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| | 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 September 30, | | Nine Months Ended September 30, | |
| | | 2012 | 2011 | 2012 | 2011 |
| Derivatives in fair value hedging relationships (including hedged item): | | | | | |
| Commodity derivatives | Cost of products sold | $4,230 | $(3,559) | $28,887 | $18,732 |

| | Location of Gain/(Loss) Recognized in Income on Derivatives | Amount of Gain/(Loss) Recognized in Income on Derivatives | | | |
|---|---|---|---|---|---|
| | | Three Months Ended September 30, | | Nine Months Ended September 30, | |
| | | 2012 | 2011 | 2012 | 2011 |
| Derivatives not designated as hedging instruments: | | | | | |
| Commodity derivatives - Trading | Cost of products sold | $4,196 | $— | $(7,099) | $— |
| Commodity derivatives - Non-trading | Cost of products sold | (6,052) | 9,175 | $(13,567) | $4,174 |
| Interest rate derivatives | Losses on non-hedged interest rate derivatives | (65) | (68,595) | (8,087) | (64,705) |
| Total | | $(1,921) | $(59,420) | $(28,753) | $(60,531) |

16. RELATED PARTY TRANSACTIONS:

In the ordinary course of business, we provide Regency with certain natural gas and NGLs sales and transportation services and compression equipment, and Regency provides us with certain contract compression services. In the ordinary course of business, we provide Southern Union with certain natural gas and NGLs sales, and Southern Union provides us with certain natural gas and NGLs sales and transportation services. These related party transactions are generally based on transactions made at market-related rates.

ETE has agreements with subsidiaries to provide or receive various general and administrative services. ETE pays us to provide services on its behalf and the behalf of other subsidiaries of ETE, which includes the reimbursement of various general and administrative services for expenses incurred by us on behalf of Regency. Southern Union also pays us to provide services on its behalf.

The following table summarizes certain related party transactions by counterparty for the three and nine months ended September 30, 2012 and 2011 for our current related parties.

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Management Fees Received: | | | | |
| ETE | $4,425 | $4,350 | $13,275 | $12,729 |
| Southern Union | 2,323 | N/A [1] | 3,840 | N/A [1] |
| Sales to Related Parties: | | | | |
| Regency | 10,403 | 6,902 | 23,884 | 25,855 |
| Southern Union | 8,523 | N/A [1] | 14,514 [1] | N/A [1] |
| Purchases from Related Parties: | | | | |
| Regency | (9,482) | (7,234) | (23,612) | (26,433) |

| | | | | |
|---|---|---|---|---|
| Southern Union | (11,239) | N/A [1] | (19,434) [1] | N/A [1] |

(1) Southern Union became a related party on March 26, 2012 as a result of ETE's acquisition of Southern Union. Transactions prior to that date are not reflected.

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Transactions between us and Enterprise were previously considered to be related party transactions due to Enterprise's ownership of a portion of ETE's limited partner interests. During the three and nine months ended September 30, 2011, ETP recorded sales to Enterprise of $164.7 million and $473.0 million, respectively, and purchases from Enterprise of $90.6 million and $350.7 million, respectively, all of which were related party transactions based on Enterprise's interests in ETE at the time of the transactions.

17. OTHER INFORMATION:

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

Other Current Assets

Other current assets consisted of the following:

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Deposits paid to vendors | $38,049 | $66,231 |
| Prepaid expenses and other | 76,275 | 115,138 |
| Total other current assets | $114,324 | $181,369 |

Other Non-Current Assets, net

Other non-current assets, net consisted of the following:

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Unamortized financing costs (3 to 30 years) | $56,295 | $46,618 |
| Regulatory assets | 87,023 | 88,993 |
| Other | 13,811 | 23,990 |
| Total other non-current assets, net | $157,129 | $159,601 |

Accrued and Other Current Liabilities

Accrued and other current liabilities consisted of the following:

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Interest payable | $143,728 | $142,616 |
| Customer advances and deposits | 16,653 | 84,300 |
| Accrued capital expenditures | 378,043 | 196,789 |
| Accrued wages and benefits | 43,720 | 67,266 |
| Taxes payable other than income taxes | 92,950 | 77,073 |
| Income taxes payable | 9,583 | 14,422 |
| Other | 38,458 | 46,736 |
| Total accrued and other current liabilities | $723,135 | $629,202 |

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18. REPORTABLE SEGMENTS:

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

- intrastate natural gas transportation and storage;
- interstate natural gas transportation;
- midstream;
- NGL transportation and services; and
- retail propane and other retail propane related operations.

Intersegment and intrasegment transactions are generally based on transactions made at market-related rates. Consolidated revenues and expenses reflect the elimination of all material intercompany transactions.

Revenues from our intrastate transportation and storage segment are primarily reflected in natural gas sales and gathering, transportation and other fees. Revenues from our interstate transportation segment are primarily reflected in gathering transportation and other fees. Revenues from our midstream segment are primarily reflected in natural gas sales, NGL sales and gathering, transportation and other fees. Revenues from our NGL transportation and services segment are primarily reflected in NGL sales and gathering, transportation and other fees. Revenues from our retail propane and other retail propane related segment are primarily reflected in retail propane sales and other.

We previously reported segment operating income as a measure of segment performance. We have revised certain reports provided to our chief operating decision maker to assess the performance of our business to reflect Segment Adjusted EBITDA. We define Segment Adjusted EBITDA as earnings before interest, taxes, depreciation, amortization and other non-cash items, such as non-cash compensation expense, gains and losses on disposals of assets, the allowance for equity funds used during construction, unrealized gains and losses on commodity risk management activities, non-cash impairment charges, loss on extinguishment of debt, gain on deconsolidation and other non-operating income or expense items. Unrealized gains and losses on commodity risk management activities includes unrealized gains and losses on commodity derivatives and inventory fair value adjustments (excluding lower of cost or market adjustments). Segment Adjusted EBITDA reflects amounts for less than wholly owned subsidiaries and unconsolidated affiliates based on the Partnership's proportionate ownership. Based on the change in our segment performance measure, we have recast the presentation of our segment results for the prior year to be consistent with the current year presentation.

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

| | Three Months Ended September 30, | | Nine Months Ended September 30, | |
|---|---|---|---|---|
| | 2012 | 2011 | 2012 | 2011 |
| Revenues: | | | | |
| Intrastate natural gas transportation and storage: | | | | |
| Revenues from external customers | $502,562 | $617,244 | $1,401,595 | $1,849,575 |
| Intersegment revenues | 52,281 | 33,590 | 129,782 | 245,512 |
| | 554,843 | 650,834 | 1,531,377 | 2,095,087 |
| Interstate natural gas transportation — revenues from external customers | 131,989 | 120,065 | 387,165 | 330,016 |
| Midstream: | | | | |
| Revenues from external customers | 549,197 | 551,393 | 1,437,487 | 1,455,017 |
| Intersegment revenues | 107,718 | 78,742 | 304,754 | 421,154 |
| | 656,915 | 630,135 | 1,742,241 | 1,876,171 |
| NGL transportation and services: | | | | |
| Revenues from external customers | 156,909 | 131,284 | 459,028 | 224,970 |
| Intersegment revenues | 11,404 | 15,312 | 37,313 | 20,446 |
| | 168,313 | 146,596 | 496,341 | 245,416 |
| Retail propane and other retail propane related — revenues from external customers | — | 236,781 | 92,972 | 1,037,969 |
| All other: | | | | |
| Revenues from external customers | 79,817 | 44,696 | 162,515 | 96,433 |
| Intersegment revenues | 28,277 | 5,059 | 65,355 | 45,958 |
| | 108,094 | 49,755 | 227,870 | 142,391 |
| Eliminations | (199,680) | (132,703) | (537,204) | (733,070) |
| Total revenues | $1,420,474 | $1,701,463 | $3,940,762 | $4,993,980 |

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| | Three Months Ended September 30, 2012 | 2011 | Nine Months Ended September 30, 2012 | 2011 |
|---|---|---|---|---|
| Segment Adjusted EBITDA | | | | |
| Intrastate transportation and storage | $120,593 | $170,183 | $469,810 | $514,547 |
| Interstate transportation | 204,488 | 102,312 | 501,888 | 265,920 |
| Midstream | 105,252 | 103,233 | 298,915 | 273,829 |
| NGL transportation and services | 36,445 | 30,504 | 110,623 | 55,200 |
| Retail propane and other retail propane related | 3,977 | (3,667) | 94,476 | 150,924 |
| All other | 10,910 | 1,587 | 8,362 | 3,167 |
| Total | 481,665 | 404,152 | 1,484,074 | 1,263,587 |
| Depreciation and amortization | (94,812) | (106,419) | (282,485) | (294,356) |
| Interest expense, net of interest capitalized | (112,141) | (124,000) | (383,271) | (347,706) |
| Gain on deconsolidation of Propane Business | — | — | 1,056,709 | — |
| Losses on non-hedged interest rate derivatives | (65) | (68,595) | (8,087) | (64,705) |
| Non-cash unit-based compensation expense | (9,198) | (10,350) | (30,190) | (31,139) |
| Unrealized gains (losses) on commodity risk management activities | 11,456 | (6,441) | (59,519) | 1,213 |
| Loss on extinguishment of debt | — | — | (115,023) | — |
| Adjusted EBITDA attributable to noncontrolling interest | 13,188 | 13,152 | 44,246 | 23,737 |
| Adjusted EBITDA attributable to discontinued operations | (4,760) | (5,007) | (15,183) | (15,028) |
| Adjusted EBITDA attributable to unconsolidated affiliates | (105,359) | (15,229) | (301,559) | (37,623) |
| Equity in earnings of unconsolidated affiliates | 7,920 | 6,713 | 63,011 | 13,386 |
| Other | 6,245 | (6,344) | 8,347 | (6,559) |
| Income from continuing operations before income tax expense | $194,139 | $81,632 | $1,461,070 | $504,807 |

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| Total assets: | | |
| Intrastate natural gas transportation and storage | $4,672,454 | $4,784,630 |
| Interstate natural gas transportation | 5,586,652 | 3,661,098 |
| Midstream | 3,246,326 | 2,665,610 |
| NGL transportation and services | 3,451,925 | 2,360,095 |
| Retail propane and other retail propane related | — | 1,783,770 |
| All other | 1,340,203 | 263,413 |
| Total | $18,297,560 | $15,518,616 |

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

(Tabular dollar amounts are in thousands)

The following is a discussion of our historical consolidated financial condition and results of operations, and should be read in conjunction with our historical consolidated financial statements and accompanying notes thereto included elsewhere in this Quarterly Report on Form 10-Q and our Annual Report on Form 10-K for the year ended December 31, 2011 filed with the SEC on February 22, 2012. This discussion includes forward-looking statements that are subject to risk and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in "Part II - Item 1A. Risk Factors", included in this report, and in "Part I - Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2011.

References to "we," "us," "our," the "Partnership" and "ETP" shall mean Energy Transfer Partners, L.P. and its subsidiaries.

Overview

The activities in which we are engaged and the wholly-owned operating subsidiaries through which we conduct those activities are as follows:

- Natural gas operations, including the following segments:
  - natural gas midstream and intrastate transportation and storage through La Grange Acquisition, L.P., which conducts business under the assumed name of ETC OLP; and
  - interstate natural gas transportation services through ET Interstate. ET Interstate is the parent company of Transwestern, ETC FEP, ETC Tiger and CrossCountry.
- NGL transportation, storage and fractionation services primarily through Lone Star.
- Other operations, including natural gas compression services through ETC Compression.

Previously we conducted our retail propane activities through HOLP and Titan. On January 12, 2012, we contributed HOLP and Titan to AmeriGas, as discussed in Note 5 of the consolidated financial statements included in Item 1.

Recent Developments

Sunoco Merger

On October 5, 2012, Sam Acquisition Corporation, a Pennsylvania corporation and a wholly-owned subsidiary of ETP, completed its merger with Sunoco, Inc. ("Sunoco"). Under the terms of the merger agreement, Sunoco shareholders received a total of approximately 54,971,724 ETP Common Units and a total of approximately $2.6 billion in cash.

ETP used approximately $2.0 billion of Sunoco's cash on hand to partially fund the cash portion of the Sunoco Merger consideration. The remainder of the cash portion of the merger consideration, approximately $620 million, was funded with borrowings on ETP's Credit Facility.

Sunoco generates cash flow from a portfolio of retail outlets for the sale of gasoline and middle distillates in the east coast, midwest and southeast areas of the United States. Prior to October 5, 2012, Sunoco also owned a 2% general partner interest, 100% of the IDRs, and 32.4% of the outstanding common units of Sunoco Logistics. In addition, in September 2012, Sunoco completed its exit from the refining business as a result of the contribution of its Philadelphia refinery to a joint venture and the related sale of its crude oil and refined product inventory to this joint venture. In connection with this transaction, Sunoco received a 33% non-operating minority interest in this joint venture.

Sunoco Logistics is a publicly traded limited partnership that owns and operates a logistics business consisting of a geographically diverse portfolio of complementary pipeline, terminalling and crude oil acquisition and marketing assets. The refined products pipelines business consists of refined products pipelines located in the northeast, midwest and southwest United States, and equity interests in refined products pipelines. The crude oil pipeline business consists of crude oil pipelines located principally in Oklahoma and Texas. The terminal facilities business consists of refined products and crude oil terminal capacity at the Nederland Terminal on the Gulf Coast of Texas and capacity at the Eagle Point terminal on the banks of the Delaware River in New Jersey. The crude oil acquisition and marketing business, principally conducted in Oklahoma and Texas, involves the acquisition and marketing of crude oil and consists of crude oil transport trucks and crude oil truck unloading facilities.

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Holdco Transaction

Immediately following the closing of the Sunoco Merger, ETE contributed its interest in Southern Union into ETP Holdco Corporation (“Holdco”), an ETP-controlled entity, in exchange for a 60% equity interest in Holdco. In conjunction with ETE's contribution, ETP contributed its interest in Sunoco to Holdco and will retain a 40% equity interest in Holdco. Prior to the contribution of Sunoco to Holdco, Sunoco contributed $2.0 billion of cash and its interests in Sunoco Logistics to ETP in exchange for 90,706,000 Class F Units representing limited partner interests in ETP ("Class F Units"). The Class F Units are entitled to 35% of the quarterly cash distribution generated by ETP and its subsidiaries other than Holdco, subject to a maximum cash distribution of $3.75 per Class F Unit per year, which is the current level. Pursuant to a stockholders agreement between ETE and ETP, ETP will control Holdco. Consequently, ETP consolidated Holdco (including Sunoco and Southern Union) in its financial statements subsequent to consummation of the Holdco Transaction.

Under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The relinquishment will apply to the distribution paid with respect to the third quarter ended September 30, 2012.

Discontinued Operations

In October 2012, we sold ETC Canyon Pipeline, LLC (“Canyon”) for approximately $207 million. The results of continuing operations of Canyon have been reclassified to loss from discontinued operations and the prior year amounts have been restated to present Canyon's operations as discontinued operations. Canyon's assets and liabilities have been reclassified and reported as assets and liabilities held for sale as of September 30, 2012. A write down of the carrying amounts of the Canyon assets to their fair values was recorded for approximately $145 million during the three months ended September 30, 2012.

General

Our primary objective is to increase the level of our distributable cash flow over time by pursuing a business strategy that is currently focused on growing our natural gas and NGL businesses through, among other things, pursuing certain construction and expansion opportunities relating to our existing infrastructure and acquiring certain strategic operations and businesses or assets. The actual amounts of cash that we will have available for distribution will primarily depend on the amount of cash we generate from our operations.

Prior to the completion of the Sunoco Merger and Holdco Transaction on October 5, 2012, our principal operations included the following segments:

- Intrastate natural gas transportation and storage – Revenue is principally generated from fees charged to customers to reserve firm capacity on or move gas through our pipelines on an interruptible basis. Our interruptible or short-term business is generally impacted by basis differentials between delivery points on our system and the price of natural gas. The basis differentials that have the greatest impact on our interruptible business are primarily between West Texas and East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold. Conversely, when basis differentials widen, our interruptible volumes and fees generally increase. The fee structure normally consists of a monetary fee and fuel retention. Excess fuel retained after consumption, if any, is typically sold at market prices. In addition to transport fees, we generate revenue from purchasing natural gas and transporting it across our system. The natural gas is then sold to electric utilities, independent power plants, local distribution companies, industrial end-users and other marketing companies. The HPL System purchases natural gas at the wellhead for transport and selling. Other pipelines with access to West Texas supply, such as Oasis and ET Fuel, may also purchase gas at the wellhead and other supply sources for transport across our system to be sold at market on the east side of our system. This activity allows our intrastate transportation and storage segment to capture the current basis differentials between delivery points on our system or to capture basis differentials that were previously locked in through hedges. Firm capacity long-term contracts are typically not subject to price differentials between shipping locations.

We also generate fee-based revenue from our natural gas storage facilities by contracting with third parties for their use of our storage capacity. From time to time, we inject and hold natural gas in our Bammel storage facility to take advantage of contango markets, a term used to describe a pricing environment 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. Our earnings from natural gas storage we purchase, store and sell are subject to the current market prices (spot price in relation to forward price) at the time the storage gas is hedged. At the inception of the hedge, we lock in a margin by purchasing gas in the spot market and entering into a financial derivative to lock in the forward sale price. If we designate the related financial derivative as a fair value hedge for accounting purposes, we value the hedged natural gas inventory at current spot market prices whereas the financial derivative is valued using forward natural gas prices. As a result of fair value hedge accounting, we have elected to exclude the spot forward premium from the measurement of effectiveness and changes in the spread between forward natural gas prices and spot market prices result in unrealized gains or losses until the underlying physical

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gas is withdrawn and the related financial 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. If the spread narrows between spot and forward prices, we will record unrealized gains or lower unrealized losses. If the spread widens prior to withdrawal of the gas, we will record unrealized losses or lower unrealized gains.

As noted above, any excess retained fuel is sold at market prices. To mitigate commodity price exposure, we will use financial derivatives to hedge prices on a portion of natural gas volumes retained. 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.

In addition, we use financial derivatives to lock in price differentials between market hubs connected to our assets on a portion of our intrastate transportation system's unreserved capacity. Gains and losses on these financial derivatives are dependent on price differentials at market locations, primarily points in West Texas and East Texas. We account for these derivatives using mark-to-market accounting, and the change in the value of these derivatives is recorded in earnings. During the fourth quarter of 2011, we began using derivatives for trading purposes.

- Interstate natural gas transportation – The majority of our interstate transportation revenues are generated through firm reservation charges that are based on the amount of firm capacity reserved for our firm shippers regardless of usage. Shippers on our interstate pipelines pay reservation charges for the firm capacity reserved for their use under multi-year contracts. In addition to reservation revenues, additional revenue sources include interruptible transportation charges as well as usage rates and overrun rates paid by firm shippers based on their actual capacity usage.
- Midstream – Revenue is principally dependent upon the volumes of natural gas gathered, compressed, treated, processed, purchased and sold through our pipelines as well as the level of natural gas and NGL prices.

In addition to fee-based contracts for gathering, treating and processing, we also have percent of proceeds and keep-whole contracts, which are subject to market pricing. For percent of proceeds contracts, we retain a portion of the natural gas and NGLs processed, or a portion of the proceeds of the sales of those commodities, as a fee. When natural gas and NGL prices increase, the value of the portion we retain as a fee increases. Conversely, when prices of natural gas and NGLs decrease, so does the value of the portion we retain as a fee. For wellhead (keep-whole) contracts, we retain the difference between the price of NGLs and the cost of the gas to process the NGLs. In periods of high NGL prices relative to natural gas, our margins increase. During periods of low NGL prices relative to natural gas, our margins decrease or could become negative; however, we have the ability to bypass our processing plants to avoid negative margins that may occur from processing NGLs in the event it is uneconomical to process this gas. Our processing contracts and wellhead purchases in rich natural gas areas provide that we earn and take title to specified volumes of NGLs, which we also refer to as equity NGLs. Equity NGLs in our midstream segment are derived from performing a service in a percent of proceeds contract or produced under a keep-whole arrangement. In addition to NGL price risk, our processing activity is also subject to price risk from natural gas because, in order to process the gas, in some cases we must purchase it. Therefore, lower gas prices generally result in higher processing margins.

We conduct marketing operations in which we market certain of 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 does not originate from 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 suppliers 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 of natural gas, less the costs of transportation.

- NGL transportation and services – NGL transportation revenue is principally generated from fees charged to customers under dedicated contracts or take-or-pay contracts. Under a dedicated contract, the customer agrees to deliver the total output from particular processing plants that are connected to the NGL pipeline. Take-or-pay contracts have minimum throughput commitments requiring the customer to pay regardless of whether a fixed volume is transported. Transportation fees are market-based, negotiated with customers and competitive with regional regulated pipelines.

NGL storage revenues are derived from base storage fees and throughput fees. Base storage fees are based on the volume of capacity reserved, regardless of the capacity actually used. Throughput fees are charged for providing ancillary services, including receipt and delivery, custody transfer, rail/truck loading and unloading fees. Storage contracts may be for dedicated storage or fungible storage. Dedicated storage enables a customer to reserve an entire storage cavern, which allows the customer to inject and withdraw proprietary and often unique products. Fungible storage allows a customer to store specified quantities of NGL products that are commingled in a storage cavern with other customers' products of the same type and grade. NGL storage contracts may be entered into on a firm or interruptible basis. Under a firm basis contract, the customer obtains the right to store products in the storage caverns throughout the term of the contract; whereas, under an interruptible basis contract, the customer receives only limited assurance regarding the availability of capacity in the storage caverns.

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This segment also includes revenues earned from processing and fractionating refinery off-gas. Under these contracts we receive an O-grade stream from cryogenic processing plants located at refineries and fractionate the products into their pure components. We deliver purity products to customers through pipelines and across a truck rack located at the fractionation complex. In addition to revenues for fractionating the O-grade stream, we have percentage-of-proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percentage-of-proceeds contracts, we retain a portion of the purity NGLs and olefins processed, or a portion of the proceeds from the sales of those commodities, as a fee. When NGLs and olefin prices increase, the value of the portion we retain as a fee increases. Conversely, when NGLs and olefin prices decrease, so does the value of the portion we retain as a fee. Under our income sharing contracts, we pay the producer the equivalent energy value for their liquids, similar to a traditional keep-whole processing agreement, and then share in the residual income created by the difference between NGLs and olefin prices as compared to natural gas prices. As NGLs and olefins prices increase in relation to natural gas prices, the value of the percent we retain as a fee increases. Conversely, when NGLs and olefins prices decrease as compared to natural gas prices, so does the value of the percent we retain as a fee.

- Retail propane and other retail propane related operations – On January 12, 2012 we contributed our propane operations, excluding our cylinder exchange operations, to AmeriGas (See Note 6 of Item 1). Subsequent to this contribution our retail propane and other retail propane segment includes our investment in AmeriGas as well as our cylinder exchange business. We sold our cylinder exchange business in June 2012.

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Results of Operations
Consolidated Results

| | Three Months Ended September 30, 2012 | Three Months Ended September 30, 2011 | Change | Nine Months Ended September 30, 2012 | Nine Months Ended September 30, 2011 | Change |
|---|---|---|---|---|---|---|
| Segment Adjusted EBITDA | | | | | | |
| Intrastate transportation and storage | $120,593 | $170,183 | $(49,590) | $469,810 | $514,547 | $(44,737) |
| Interstate transportation | 204,488 | 102,312 | 102,176 | 501,888 | 265,920 | 235,968 |
| Midstream | 105,252 | 103,233 | 2,019 | 298,915 | 273,829 | 25,086 |
| NGL transportation and services | 36,445 | 30,504 | 5,941 | 110,623 | 55,200 | 55,423 |
| Retail propane and other retail propane related | 3,977 | (3,667) | 7,644 | 94,476 | 150,924 | (56,448) |
| All other | 10,910 | 1,587 | 9,323 | 8,362 | 3,167 | 5,195 |
| Total | 481,665 | 404,152 | 77,513 | 1,484,074 | 1,263,587 | 220,487 |
| Depreciation and amortization | (94,812) | (106,419) | 11,607 | (282,485) | (294,356) | 11,871 |
| Interest expense, net of interest capitalized | (112,141) | (124,000) | 11,859 | (383,271) | (347,706) | (35,565) |
| Gain on deconsolidation of Propane Business | — | — | — | 1,056,709 | — | 1,056,709 |
| Losses on non-hedged interest rate derivatives | (65) | (68,595) | 68,530 | (8,087) | (64,705) | 56,618 |
| Non-cash unit-based compensation expense | (9,198) | (10,350) | 1,152 | (30,190) | (31,139) | 949 |
| Unrealized gains (losses) on commodity risk management activities | 11,456 | (6,441) | 17,897 | (59,519) | 1,213 | (60,732) |
| Loss on extinguishment of debt | — | — | — | (115,023) | — | (115,023) |
| Adjusted EBITDA attributable to noncontrolling interest | 13,188 | 13,152 | 36 | 44,246 | 23,737 | 20,509 |
| Adjusted EBITDA attributable to discontinued operations | (4,760) | (5,007) | 247 | (15,183) | (15,028) | (155) |
| Adjusted EBITDA attributable to unconsolidated affiliates | (105,359) | (15,229) | (90,130) | (301,559) | (37,623) | (263,936) |
| Equity in earnings of unconsolidated affiliates | 7,920 | 6,713 | 1,207 | 63,011 | 13,386 | 49,625 |
| Other | 6,245 | (6,344) | 12,589 | 8,347 | (6,559) | 14,906 |
| Income from continuing operations before income tax expense | 194,139 | 81,632 | 112,507 | 1,461,070 | 504,807 | 956,263 |
| Income tax expense | (768) | (4,039) | 3,271 | (14,915) | (20,417) | 5,502 |
| Income from continuing operations | $193,371 | $77,593 | $115,778 | $1,446,155 | $484,390 | $961,765 |
| Income from discontinued operations | (147,162) | (1,543) | (145,619) | (150,062) | (4,522) | (145,540) |
| Net Income | 46,209 | 76,050 | (29,841) | 1,296,093 | 479,868 | 816,225 |

See the detailed discussion of Segment Adjusted EBITDA below.

Depreciation and Amortization. For the three and nine months ended September 30, 2012 compared to the same periods last year, depreciation and amortization decreased by approximately $20.4 million and $58.0 million, respectively, due to the deconsolidation of the Propane Business in January 2012. These decreases were offset by additional depreciation recorded from assets placed in service.

Interest Expense. For the three months ended September 30, 2012, interest expense decreased from the prior year period as a result of a reduction of several series of our higher coupon notes that were repurchased in the tender offers completed in January 2012 and also due to an increase in capitalized interest on our growth projects. For the nine months ended September 30, 2012, the impact of the repurchase was more than offset by incremental interest expense due to the issuance of $1.5 billion of senior notes in May 2011 to fund the LDH acquisition and the issuance of $2.0 billion of senior notes in January 2012 to fund the Citrus acquisition.

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Gain on Deconsolidation of Propane Business. A gain on deconsolidation was recognized as a result of the contribution of our Propane Business to AmeriGas in January 2012.

Losses on Non-Hedged Interest Rate Derivatives. The changes between the three and nine months ended September 30, 2012 compared to the same periods last year were primarily due to the recognition of losses in the prior periods resulting from significant forward rate decreases in those periods.

Income Tax Expense. The decrease in income tax expense between the periods was primarily due to changes in taxable income within our subsidiaries that are taxable corporations and deferred tax expense related to the deconsolidation of our Propane Business.

Unrealized (Losses) Gains on Commodity Risk Management Activities. See discussion of the unrealized (losses) gains on commodity risk management activities included in the discussion of segment results below.

Loss on Extinguishment of Debt. A loss on extinguishment of debt was recognized for the nine months ended September 30, 2012 in connection with our tender offers in which we repurchased approximately $750.0 million in aggregate principal amount of Senior Notes in January 2012.

Adjusted EBITDA Attributable to Noncontrolling Interest. These amounts represent the proportionate share of Lone Star's Adjusted EBITDA attributable to Regency's 30% interest in Lone Star. This amount was excluded from the measure of Segment Adjusted EBITDA. Net income includes the results attributable to Lone Star on a consolidated basis.

Adjusted EBITDA Attributable to Unconsolidated affiliates and Equity in Earnings of Unconsolidated Affiliates. Amounts reflected for 2012 primarily include our proportionate share of such amounts related to AmeriGas, Citrus and FEP. The 2011 amounts primarily represented our proportionate share of such amounts for FEP only. Such amounts were included in calculating Segment Adjusted EBITDA and net income.

Other. Includes other income and expense amounts, net and amortization of regulatory assets.

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Supplemental Information on Unconsolidated Affiliates

The following table presents equity in earnings of unconsolidated affiliates, the proportionate share of unconsolidated affiliates' interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes by unconsolidated affiliate, Adjusted EBITDA attributable to unconsolidated affiliates and distributions received from affiliates for the three and nine months ended September 30, 2012 and 2011:

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Equity in earnings of unconsolidated affiliates: | | | | | | |
| AmeriGas | $(31,970) | $— | $(31,970) | $(28,920) | $— | $(28,920) |
| Citrus | 25,225 | — | 25,225 | 49,039 | — | 49,039 |
| FEP | 14,846 | 5,870 | 8,976 | 41,041 | 11,869 | 29,172 |
| Other | (181) | 843 | (1,024) | 1,851 | 1,517 | 334 |
| Total equity in earnings of unconsolidated affiliates | $7,920 | $6,713 | $1,207 | $63,011 | $13,386 | $49,625 |
| Proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes: | | | | | | |
| AmeriGas | $35,946 | $— | $35,946 | $107,993 | $— | $107,993 |
| Citrus | 55,675 | — | 55,675 | 113,153 | — | 113,153 |
| FEP | 5,381 | 8,495 | (3,114) | 16,121 | 24,156 | (8,035) |
| Other | 437 | 21 | 416 | 1,281 | 81 | 1,200 |
| Total proportionate share of interest, depreciation, amortization, non-cash compensation expense, loss on debt extinguishment and taxes | $97,439 | $8,516 | $88,923 | $238,548 | $24,237 | $214,311 |
| Adjusted EBITDA attributable to unconsolidated affiliates: | | | | | | |
| AmeriGas | $3,976 | $— | $3,976 | $79,073 | $— | $79,073 |
| Citrus | 80,900 | — | 80,900 | 162,192 | — | 162,192 |
| FEP | 20,227 | 14,365 | 5,862 | 57,162 | 36,025 | 21,137 |
| Other | 256 | 864 | (608) | 3,132 | 1,598 | 1,534 |
| Total Adjusted EBITDA attributable to unconsolidated affiliates | $105,359 | $15,229 | $90,130 | $301,559 | $37,623 | $263,936 |
| Distributions received from unconsolidated affiliates: | | | | | | |
| AmeriGas | $23,654 | $— | $23,654 | $69,853 | $— | $69,853 |
| Citrus | 37,500 | — | 37,500 | 62,500 | — | 62,500 |
| FEP | 17,300 | 21,513 | (4,213) | 52,600 | 27,600 | 25,000 |
| Other | 2,108 | 1,223 | 885 | 4,023 | 3,694 | 329 |
| Total distributions received from unconsolidated affiliates | $80,562 | $22,736 | $57,826 | $188,976 | $31,294 | $157,682 |

Segment Operating Results

Our reportable segments are discussed below. “All other” includes our compression and wholesale propane businesses.

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With respect to our retail propane and other retail propane related segment, on January 12, 2012, we received an equity investment in AmeriGas as partial consideration for the contribution of our Propane Business to AmeriGas. As a result, the retail propane and other retail propane related segment data presented above only includes eleven days of consolidated activity related to our Propane Business for the nine months ended September 30, 2012. For the three and nine months ended September 30, 2012, the retail propane and other retail propane related segment data presented above included our equity investment in AmeriGas. Amounts attributable to our investment in AmeriGas are reflected above in "Supplemental Information on Unconsolidated Affiliates."

We evaluate segment performance based on Segment Adjusted EBITDA, which we believe is an important performance measure of the core profitability of our operations. This measure represents the basis of our internal financial reporting and is one of the performance measures used by senior management in deciding how to allocate capital resources among business segments. The tables below identify the components of Segment Adjusted EBITDA, which is calculated as follows:

- Gross margin, operating expenses, and selling, general and administrative. These line items are the amounts included in our consolidated financial statements that are attributable to each segment.

- Unrealized gains or losses on commodity risk management activities. These are the unrealized amounts that are included in cost of products sold to calculate gross margin. These amounts are not included in Segment Adjusted EBITDA; therefore, the unrealized losses are added back and the unrealized gains are subtracted to calculate the segment measure.

- Non-cash compensation expense. These amounts represent the total non-cash compensation recorded in operating expenses and selling, general and administrative. This expense is not included in Segment Adjusted EBITDA and therefore is added back to calculate the segment measure.

- Adjusted EBITDA attributable to unconsolidated affiliates. These amounts represent our proportionate share of the Adjusted EBITDA of our unconsolidated affiliates. Amounts reflected are calculated consistently with our definition of Adjusted EBITDA above.

- Adjusted EBITDA attributable to noncontrolling interest. These amounts represent the portion of Segment Adjusted EBITDA attributable to noncontrolling interest. Currently, the only noncontrolling interest reflected is the 30% interest in Lone Star that is held by Regency. We reflect this amount as noncontrolling interest because we consolidate 100% of Lone Star on our consolidated financial statements.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for year ended December 31, 2011 filed with the SEC on February 22, 2012.

Selling, General and Administrative Expenses Not Allocated to Segments. Selling, general and administrative expenses are allocated monthly to the Operating Companies using the Modified Massachusetts Formula Calculation (“MMFC”). The expenses subject to allocation are based on estimated amounts and take into consideration our actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month which results in over or under allocation of these costs due to timing differences.

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Intrastate Transportation and Storage

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Natural gas transported (MMBtu/d) | 9,942,575 | 11,148,186 | (1,205,611) | 9,995,218 | 11,367,812 | (1,372,594) |
| Revenues | $554,843 | $650,834 | $(95,991) | $1,531,377 | $2,095,087 | $(563,710) |
| Cost of products sold | 362,186 | 422,801 | (60,615) | 949,254 | 1,396,001 | (446,747) |
| Gross margin | 192,657 | 228,033 | (35,376) | 582,123 | 699,086 | (116,963) |
| Unrealized (gains) losses on commodity risk management activities | (12,364) | 5,342 | (17,706) | 54,289 | (1,368) | 55,657 |
| Operating expenses, excluding non-cash compensation expense | (45,454) | (49,336) | 3,882 | (131,318) | (144,631) | 13,313 |
| Selling, general and administrative expenses, excluding non-cash compensation expense | (12,230) | (14,869) | 2,639 | (33,858) | (40,299) | 6,441 |
| Adjusted EBITDA attributable to unconsolidated affiliates | (2,016) | 1,013 | (3,029) | (1,426) | 1,759 | (3,185) |
| Segment Adjusted EBITDA | $120,593 | $170,183 | $(49,590) | $469,810 | $514,547 | $(44,737) |

Volumes. We experienced a decrease in transported volumes for both the three and nine months ended September 30, 2012 compared to the same periods in the prior year due to an unfavorable natural gas price environment. The average spot price at Houston Ship Channel declined to $2.86/MMBtu and $2.50/MMBtu during the three and nine months ended September 30, 2012, respectively, compared to $4.10/MMBtu and $4.17/MMBtu during the three and nine months ended September 30, 2011, respectively.

Gross Margin. The components of our intrastate transportation and storage segment gross margin were as follows:

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Transportation fees | $138,991 | $148,331 | $(9,340) | $420,196 | $448,669 | $(28,473) |
| Natural gas sales and other | 21,557 | 42,981 | (21,424) | 68,064 | 106,570 | (38,506) |
| Retained fuel revenues | 21,735 | 32,560 | (10,825) | 55,102 | 104,222 | (49,120) |
| Storage margin, including fees | 10,374 | 4,161 | 6,213 | 38,761 | 39,625 | (864) |
| Total gross margin | $192,657 | $228,033 | $(35,376) | $582,123 | $699,086 | $(116,963) |

For the three months ended September 30, 2012 compared to the three months ended September 30, 2011, intrastate transportation and storage gross margin decreased primarily due to the following factors:

- Transportation fees decreased $9.3 million due to lower demand fees of $8.5 million and an unfavorable impact of $1.2 million from a decline in transported volumes.
- Margin from sales of natural gas and other activities decreased $21.4 million primarily due to a smaller gain from derivative activity of $14.8 million and a decline of $7.7 million in margin where we utilize third party processing. The margin from the natural gas sales and other includes sales and purchases of natural gas, derivatives used to hedge transportation activities, gains and losses on derivatives used to hedge net retained fuel, and trading activities using commodity derivatives. Excluding derivatives related to storage described below, unrealized gains of $6.0 million were recorded during the three months ended September 30, 2012 compared to unrealized gains of $4.0 million during the three months ended September 30, 2011.
- 

Retained fuel revenues include gross volumes retained as a fee at the current market price. Retention revenue decreased $10.8 million primarily due to a decrease in natural gas prices as noted above and lower retained volumes of 0.8 Bcf. The cost of retained fuel consumed in operations is included in operating expenses.

For the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011, intrastate transportation

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and storage gross margin decreased primarily due to the following factors:

- Transportation fees decreased $28.5 million primarily due to lower demand fees of $20.6 million. Additionally, there was an unfavorable impact of $7.8 million attributable to a decline in transported volumes.
- Margin from sales of natural gas and other activities decreased $38.5 million primarily due to a decline of $25.8 million in margin where we utilize third party processing and a decrease of $28.7 million in our commercial optimization activities which were partially offset by an increase in wellhead margin on our HPL system of $16.2 million.
- Retained fuel revenues decreased $49.1 million primarily due to a decrease in natural gas prices as noted above and lower retained volumes of 2.5 Bcf.

Storage margin was comprised of the following:

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Withdrawals from storage natural gas inventory (MMBtu) | 5,258,344 | 8,661,359 | (3,403,015) | 9,698,738 | 24,443,485 | (14,744,747) |
| Margin on physical sales | $(3,203) | $154 | $(3,357) | $(11,157) | $10,845 | $(22,002) |
| Settlements of derivatives | 15 | 5,421 | (5,406) | 87,480 | 5,992 | 81,488 |
| Realized margin (loss) on natural gas inventory transactions | (3,188) | 5,575 | (8,763) | 76,323 | 16,837 | 59,486 |
| Fair value inventory adjustments | 19,335 | (27,603) | 46,938 | 17,263 | (22,772) | 40,035 |
| Unrealized gains (losses) on derivatives | (12,953) | 18,231 | (31,184) | (77,620) | 20,024 | (97,644) |
| Margin recognized on natural gas inventory and related derivatives | 3,194 | (3,797) | 6,991 | 15,966 | 14,089 | 1,877 |
| Revenues from fee-based storage | 7,364 | 8,072 | (708) | 23,254 | 25,891 | (2,637) |
| Other costs | (184) | (114) | (70) | (459) | (355) | (104) |
| Total storage margin | $10,374 | $4,161 | $6,213 | $38,761 | $39,625 | $(864) |

The increase in storage margin for the three months ended September 30, 2012 compared to the three months ended September 30, 2011 was principally driven by an increase in inventory valuation and derivatives settled during the period. The decrease in storage margin for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011 was due to fewer withdraws and a decline in fee-based revenue resulting from the cessation of 4.5 Bcf in fee-based contracts in 2011. These decreases were partially offset by realized gains on the settlement of derivatives during the nine month period compared to the same periods in the prior year.

Unrealized Gains (Losses) on Commodity Risk Management Activities. Unrealized losses on commodity risk management activities reflect the net impact from unrealized gains and losses on storage and non-storage derivatives as well as fair value adjustments on inventory. Unrealized gains increased for the three months ended September 30, 2012 primarily due to the impacts of fair value accounting as prices increased during the third quarter of 2012. Unrealized losses for the nine months ended September 30, 2012 were primarily due to derivatives related to our stored natural gas.

Operating Expenses, Excluding Non-Cash Compensation Expense. Intrastate transportation and storage operating expenses decreased during the three months ended September 30, 2012 compared to the same period last year principally due to a decrease in natural gas consumed for compression of $2.3 million and a reduction in electricity costs of $1.2 million and various other expenses of $0.4 million. For the nine months ended September 30, 2012 compared to the same period last year, operating expenses decreased due to a decrease in natural gas consumed for compression of $15.3 million offset by increases in various other expenses of $2.0 million.

Selling, General and Administrative, Excluding Non-Cash Compensation Expense. For the three and nine months ended September 30, 2012 compared to the same periods last year, intrastate transportation and storage selling, general and administrative expenses decreased as a result of a decrease in employee-related costs (including allocated overhead expenses).

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Interstate Transportation

| | Three Months Ended September 30, 2012 | 2011 | Change | Nine Months Ended September 30, 2012 | 2011 | Change |
|---|---|---|---|---|---|---|
| Natural gas transported (MMBtu/d) | 3,059,915 | 3,155,559 | (95,644) | 3,015,458 | 2,709,522 | 305,936 |
| Natural gas sold (MMBtu/d) | 16,976 | 21,808 | (4,832) | 18,416 | 22,859 | (4,443) |
| Revenues | $131,989 | $120,065 | $11,924 | $387,165 | $330,016 | $57,149 |
| Operating expenses, excluding non-cash compensation, amortization and accretion expenses | (19,594) | (21,338) | 1,744 | (76,735) | (73,513) | (3,222) |
| Selling, general and administrative expenses, excluding non-cash compensation, amortization and accretion expenses | (9,034) | (10,814) | 1,780 | (27,896) | (26,743) | (1,153) |
| Adjusted EBITDA attributable to unconsolidated affiliates | 101,127 | 14,399 | 86,728 | 219,354 | 36,160 | 183,194 |
| Segment Adjusted EBITDA | $204,488 | $102,312 | $102,176 | $501,888 | $265,920 | $235,968 |

Volumes. For the three months ended September 30, 2012 compared to the same period in the prior year, transported volumes decreased primarily due to maintenance on the western side of the Transwestern pipeline and lower basis differentials on the eastern side of the Transwestern pipeline. The volume decrease on the Transwestern pipeline was offset by additional transported volumes of approximately 32.6 MMBtu/d related to the expansion of the Tiger pipeline. For the nine months ended September 30, 2012 compared to the same period in the prior year, the increase in transported volumes is primarily due to the Tiger pipeline expansion.

For the three and nine months ended September 30, 2012 compared to the same periods in the prior year, operational sales volumes decreased on the Transwestern pipeline principally as a result of unfavorable market conditions.

Revenues. Interstate transportation revenues increased during the three and nine months ended September 30, 2012 compared to the same periods in the prior year as a result of $17.5 million and $77.0 million, respectively, in incremental reservation fees related to the Tiger pipeline expansion. The increases for the three and nine months ended September 30, 2012 were partially offset by decreased revenues from the Transwestern pipeline as a result of lower margin and volumes driven principally by lower basis differentials on the eastern side of the pipeline.

Operating Expenses, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. Interstate transportation operating expenses decreased during the three months ended September 30, 2012 compared to the same period in the prior year primarily due to a decrease in property taxes related to assessed values on the Tiger pipeline. For the nine months ended September 30, 2012 compared to the same period in the prior year, the increase in operating expenses reflected higher property taxes related to the Tiger pipeline expansion.

Selling, General and Administrative, Excluding Non-Cash Compensation, Amortization and Accretion Expenses. For the three and nine months ended September 30, 2012 compared to the same periods in the prior year, the variances in selling, general and administrative expenses were primarily due to changes in allocated corporate and pipeline costs and employee-related costs.

Adjusted EBITDA Attributable to Unconsolidated Affiliates. Adjusted EBITDA from unconsolidated affiliates increased for the three and nine months ended September 30, 2012 compared to the same periods in the prior year due to increases of $80.9 million and $162.2 million, respectively, from Citrus and $5.9 million and $21.1 million, respectively, from FEP. We acquired a 50% interest in Citrus on March 26, 2012. The increases related to FEP were primarily due to incremental reservation revenues resulting from additional capacity under contractual commitments.

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Midstream

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Gathered volumes (MMBtu/d) | 2,463,987 | 2,204,792 | 259,195 | 2,327,284 | 1,939,398 | 387,886 |
| NGLs produced (Bbls/d) | 83,736 | 55,943 | 27,793 | 77,038 | 51,824 | 25,214 |
| Equity NGLs produced (Bbls/d) | 15,890 | 16,269 | (379) | 18,582 | 16,142 | 2,440 |
| Revenues | $656,915 | $630,135 | $26,780 | $1,742,241 | $1,876,171 | $(133,930) |
| Cost of products sold | 528,311 | 507,806 | 20,505 | 1,366,428 | 1,541,158 | (174,730) |
| Gross margin | 128,604 | 122,329 | 6,275 | 375,813 | 335,013 | 40,800 |
| Unrealized (gains) losses on commodity risk management activities | 214 | (919) | 1,133 | 2,381 | (2,091) | 4,472 |
| Operating expenses, excluding non-cash compensation expense | (18,948) | (17,930) | (1,018) | (68,849) | (59,795) | (9,054) |
| Selling, general and administrative expenses, excluding non-cash compensation expense | (9,378) | (5,254) | (4,124) | (25,613) | (14,326) | (11,287) |
| Adjusted EBITDA attributable to discontinued operations | 4,760 | 5,007 | (247) | 15,183 | 15,028 | 155 |
| Segment Adjusted EBITDA | $105,252 | $103,233 | $2,019 | $298,915 | $273,829 | $25,086 |

Volumes. For the three months ended September 30, 2012 compared to the same period last year, NGL production increased primarily due to increased inlet volumes at our La Grange and Chisolm plants as a result of increased capacity from growth projects and more production in the Eagle Ford Shale area. The decrease in equity NGL production was primarily due to a higher concentration of volumes under fee-based contracts during the three months ended September 30, 2012 compared to the same period last year.

For the nine months ended September 30, 2012 compared to the same period last year, NGL production increased primarily due to increased inlet volumes at our La Grange and Chisolm plants as a result of increased capacity from growth projects and more production in the Eagle Ford Shale area offset by reduced inlet volumes at our Godley plant as a result of lower production in the Barnett Shale. The increase in equity NGL production was primarily due to higher overall production and was offset by a higher concentration of volumes under fee-based contracts during the nine months ended September 30, 2012 as compared to the same period last year.

Gross Margin. The components of our midstream segment gross margin were as follows:

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Gathering and processing fee-based revenues | $81,336 | $61,177 | $20,159 | $226,225 | $172,809 | $53,416 |
| Non fee-based contracts and processing | 54,572 | 66,830 | (12,258) | 169,441 | 174,433 | (4,992) |
| Other | (7,304) | (5,678) | (1,626) | (19,853) | (12,229) | (7,624) |
| Total gross margin | $128,604 | $122,329 | $6,275 | $375,813 | $335,013 | $40,800 |

For the three months ended September 30, 2012, midstream gross margin increased compared to the same period last year due to the following:

- Increased volumes, primarily as a result of increased capacity from growth projects in the Eagle Ford Shale, resulted in increased fee-based revenues of $20.2 million.

- Our non fee-based gross margins decreased $12.3 million primarily due to lower NGL prices. The composite NGL price decreased to $0.86 per gallon for the three months ended September 30, 2012 from $1.33 per gallon during the same period last year.

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For the nine months ended September 30, 2012, midstream gross margin increased compared to the same period last year due to the following:

- Increased volumes, primarily as a result of increased capacity from growth projects in the Eagle Ford Shale, resulted in increased fee-based revenues of $53.4 million for the nine months ended September 30, 2012 as compared with the same period last year.

- Our non fee-based gross margins decreased $5.0 million primarily due to lower NGL prices. The composite NGL price decreased to $0.99 per gallon for the nine months ended September 30, 2012 from $1.29 per gallon during the same period last year.

Unrealized (Gains) Losses on Commodity Risk Management Activities. Our midstream segment recorded unrealized losses of $0.2 million during the three months ended September 30, 2012 compared to unrealized gains of $0.9 million in the same period last year. For the nine months ended September 30, 2012, we recorded unrealized losses of $2.4 million compared to unrealized gains of $2.1 million in the same period last year.

Operating Expenses, Excluding Non-Cash Compensation Expense. Increases in midstream operating expenses for the three and nine months ended September 30, 2012 compared to the same periods in the prior year were primarily attributable to incremental operating expenses from new assets placed into service in the Eagle Ford Shale. Midstream operating expenses increased for the three months ended September 30, 2012 compared to the same period in the prior year primarily due to an increase in operating expenses of $0.4 million, an increase in ad valorem taxes of $0.6 million and an increase in employee related costs of $0.9 million. These costs were offset by reduced maintenance costs related to our midstream assets in Louisiana of $0.9 million. For the nine months ended September 30, 2012 compared to the same period in the prior year, midstream operating expenses increased primarily due to an increase in ad valorem taxes of $4.1 million, an increase in operating expenses of $2.7 million, an increase in maintenance expenses of $0.4 million, and an increase in employee related costs of $1.8 million.

Selling, General and Administrative Expenses, Excluding Non-Cash Compensation Expense. Midstream selling, general and administrative expenses increased for the three and nine months ended September 30, 2012 compared to the same periods in the prior year primarily due to additional assets placed into service in the Eagle Ford Shale. The expenses increased for the three months ended September 30, 2012, compared to the same period last year due to increases in employee related costs of $1.6 million, an increase in professional fees of $1.3 million, an increase of insurance costs of $0.9 million and an increase of office expenses of $0.3 million. For the nine months ended September 30, 2012, selling, general and administrative expenses increased compared to the same period in the prior year due to increased employee costs of $6.2 million, an increase in insurance costs of $1.9 million, an increase in professional fees of $1.6 million and an increase in office expenses of $1.6 million.

NGL Transportation and Services

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| NGL transportation volumes (Bbls/d) | 174,234 | 133,149 | 41,085 | 166,825 | 131,147 | 35,678 |
| NGL fractionation volumes (Bbls/d) | 11,442 | 13,833 | (2,391) | 17,530 | 14,912 | 2,618 |
| Revenues | $168,313 | $146,596 | $21,717 | $496,341 | $245,416 | $250,925 |
| Cost of products sold | 101,222 | 81,224 | 19,998 | 285,210 | 133,628 | 151,582 |
| Gross margin | 67,091 | 65,372 | 1,719 | 211,131 | 111,788 | 99,343 |
| Operating expenses, excluding non-cash compensation expense | (13,104) | (16,575) | 3,471 | (43,074) | (23,062) | (20,012) |
| Selling, general and administrative expenses, excluding non-cash compensation expense | (5,230) | (4,958) | (272) | (15,421) | (9,606) | (5,815) |
| Adjusted EBITDA attributable to unconsolidated affiliates | 876 | (183) | 1,059 | 2,233 | (183) | 2,416 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Adjusted EBITDA attributable to noncontrolling interest | (13,188 ) | (13,152 ) | (36 ) | (44,246 ) | (23,737 ) | (20,509 ) |
| Segment Adjusted EBITDA | $36,445 | $30,504 | $5,941 | $110,623 | $55,200 | $55,423 |

Our NGL Transportation and Services segment reflects the results from Lone Star, which was formed in 2011 and acquired all of the membership interests in LDH on May 2, 2011, as well as other wholly-owned or joint venture pipelines that have recently

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become operational. The volumes reflected above for the nine months ended September 30, 2011 represent average daily volumes for the period from May 2, 2011 to September 30, 2011.

Volumes. NGL transportation volumes increased for the three and nine months ended September 30, 2012 as compared to the same periods in the prior year primarily due to an increase in volumes transported on our wholly-owned NGL pipelines originating from our La Grange and Chisholm plants as a result of increased production in the Eagle Ford area. Fractionation volumes decreased at our Geismar fractionation complex in Louisiana for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011 due to refinery closures as a result of Hurricane Isaac and refinery downtime. Average daily fractionation volumes increased for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011 due to significant refinery downtime in July and August of 2011; this downtime impacted both the three- and nine-month variances but had a greater impact on the nine-month comparison due to fewer operational days being included in the prior year subsequent to the consolidation of LDH.

Gross Margin. The components of our NGL transportation and services segment gross margin were as follows:

| | Three Months Ended September 30, | | | Nine Months Ended September 30, | | |
|---|---|---|---|---|---|---|
| | 2012 | 2011 | Change | 2012 | 2011 | Change |
| Storage margin | $33,986 | $34,287 | (301) | $96,177 | $57,702 | $38,475 |
| Transportation fees | 21,069 | 13,646 | 7,423 | 51,818 | 20,696 | 31,122 |
| Processing and fractionation margin | 11,587 | 16,602 | (5,015) | 62,692 | 33,324 | 29,368 |
| Other margin | 449 | 837 | (388) | 444 | 66 | 378 |
| Total gross margin | $67,091 | $65,372 | $1,719 | $211,131 | $111,788 | $99,343 |

For the three months ended September 30, 2012 compared to the same period in the prior year, NGL transportation and services segment gross margin increased compared to the same period last year due to the following:

- Increased volumes on our wholly-owned NGL pipelines due to increased activity related to the Eagle Ford Shale resulted in an increase of $3.4 million in transportation fees. Additionally, increased transportation rates on our Lone Star West Texas Pipeline due to a project to increase our capacity out of West Texas resulted in an increase of $4.0 million in transportation fees.

- We experienced a decrease in our processing and fractionation margin due to a significant decline in NGL and olefins prices. We were also impacted by downtime of the refineries we serve as a result of Hurricane Isaac during the three months ended September 30, 2012 which reduced processing and fractionation margin by approximately $4.0 million.

For the nine months ended September 30, 2012 compared to the same period in the prior year, the increase in NGL transportation and services segment gross margin reflected a full nine months of activity compared to only five months of activity in 2011. Additionally, gross margin for the nine months ended September 30, 2012 was impacted by the following items which did not have a comparable impact in the prior period:

- We recorded a $1.6 million lower-of-cost or market write-down on inventory held as of June 30, 2012 in our storage facility and pipelines.

- Downtime related to Hurricane Isaac resulted in an approximate $4.0 million decrease to our processing and fractionation margin.

- Commissioning of the Freedom Pipeline, Liberty Pipeline and partial commissioning of the Justice Pipeline contributed $6.8 million for the nine months ended September, 30, 2012.

Operating Expenses. For the three months ended September 30, 2012 compared to the three months ended September 30, 2011, NGL Transportation and Services operating expenses reflected an increase in maintenance expenses offset by a decrease in ad valorem taxes. For the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011, the increase in operating expenses is due to ownership of Lone Star for nine months in 2012 compared to five months in 2011.

Selling, General and Administrative. NGL Transportation and Storage selling, general and administrative expenses increased for the nine months ended September 30, 2012 due to ownership of Lone Star for nine months in 2012 compared to five months in 2011.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our Unitholders will depend on our future performance, which will be subject to prevailing economic, financial, business and weather conditions, and other factors, many of which are beyond management's control.

We currently believe that our business has the following future capital requirements, which do not include capital requirements related to Holdco:

- growth capital expenditures for our midstream and intrastate transportation and storage segments, primarily for the construction of new pipelines and compression, for which we expect to spend between $200 million and $225 million for the remainder of 2012 and between $350 million and $400 million for 2013;
- growth capital expenditures for our NGL transportation and services segment of between $350 million and $400 million for the remainder of 2012, for which we expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $100 million and $120 million. We also expect to spend between $400 million and $500 million in growth capital expenditures for our NGL transportation and services segment for 2013, for which we expect to receive capital contributions from Regency related to their 30% share of Lone Star of between $100 million and $150 million; and
- maintenance capital expenditures of between $30 million and $40 million for the remainder of 2012, which include (i) capital expenditures for our intrastate operations for pipeline integrity and for connecting additional wells to our intrastate natural gas systems in order to maintain or increase throughput on existing assets; (ii) capital expenditures for our interstate operations, primarily for pipeline integrity; and (iii) capital expenditures related to NGL transportation and services, including amounts expected to be funded by our joint venture partner related to its 30% interest in Lone Star. We also expect to spend between $125 million and $145 million in maintenance capital expenditures for 2013.

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe in a timely manner, higher steel prices and other factors beyond our control. However, we include these factors in our anticipated growth capital expenditures for each year.

We generally fund our capital requirements with cash flows from operating activities, borrowings under the ETP Credit Facility, the issuance of long-term debt or Common Units or a combination thereof. Based on our current estimates, we expect to utilize capacity under the ETP Credit Facility, along with cash from operations, to fund our announced growth capital expenditures and working capital needs for the next 12 months; however, we may issue debt or equity securities prior to that time as we deem prudent to provide liquidity for new capital projects, to maintain investment grade credit metrics or other partnership purposes.

We utilized the ETP Credit Facility to partially fund the cash portion of the Sunoco Merger consideration. We expect to continue to utilize the ETP Credit Facility to fund cash requirements; however, we expect to continue to prudently raise debt and equity to fund our growth capital requirements, to maintain sufficient liquidity, and to manage our credit metrics in order to maintain our investment grade credit ratings.

Cash Flows

Our internally generated cash flows may change in the future due to a number of factors, some of which we cannot control. These include regulatory changes, the price for our products and services, the demand for such products and services, margin requirements resulting from significant changes in commodity prices, operational risks, the successful integration of our acquisitions and other factors.

Operating Activities

Changes in cash flows from operating activities between periods primarily result from changes in earnings (as discussed in "Results of Operations" above), excluding the impacts of non-cash items and changes in operating assets and liabilities. Non-cash items include recurring non-cash expenses, such as depreciation and amortization expense and non-cash compensation expense. The increase in depreciation and amortization expense during the periods presented primarily resulted from construction and acquisitions of assets, while changes in non-cash unit-based compensation expense result from changes in the number of units granted and changes in the grant date fair value estimated for such grants. Cash flows from operating activities also differ from earnings as a result of non-cash charges that may not be recurring such as impairment charges and allowance for equity funds used during construction. The allowance for equity funds used during construction increases in periods when we have a significant amount of interstate pipeline construction in progress. Changes in operating assets and liabilities between periods result from factors such

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as the changes in the value of price risk management assets and liabilities, timing of accounts receivable collection, payments on accounts payable, the timing of purchase and sales of inventories, and the timing of advances and deposits received from customers.

Nine months ended September 30, 2012 compared to nine months ended September 30, 2011. Cash provided by operating activities during 2012 was $937.9 million as compared to $1.03 billion for 2011 and net income was $1.30 billion and $479.9 million for 2012 and 2011, respectively. The difference between net income and cash provided by operating activities for the nine months ended September 30, 2012 primarily consisted of the gain on the deconsolidation of the Propane Business of $1.06 billion partially offset by net changes in operating assets and liabilities of $60.3 million, loss on extinguishment of debt of $115.0 million and non-cash items totaling $498.5 million. The difference between net income and cash provided by operating activities for the nine months ended September 30, 2011 primarily consisted of non-cash items totaling $358.8 million and changes in operating assets and liabilities of $195.0 million.

The non-cash activity in 2012 and 2011 consisted primarily of depreciation and amortization of $282.5 million and $294.4 million, respectively, and non-cash compensation expense of $30.2 million and $31.1 million, respectively. In addition, non-cash activity for 2012 included a write-down of Canyon assets of $145.2 million.

Cash paid for interest, net of interest capitalized, was $420.5 million and $345.4 million for the nine months ended September 30, 2012 and 2011, respectively.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, cash contributions to our joint ventures, and cash proceeds from the contribution of the Propane Business. Changes in capital expenditures between periods primarily result from increases or decreases in our growth capital expenditures to fund our construction and expansion projects.

Nine months ended September 30, 2012 compared to nine months ended September 30, 2011. Cash used in investing activities during 2012 was $2.13 billion as compared to $3.10 billion for 2011. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2012 were $1.80 billion, including changes in accruals of $182.2 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2011 of $951.0 million, including changes in accruals of $34.4 million. In addition, in 2012 we paid cash for acquisitions of $1.91 billion, primarily for the Citrus Merger. We also received net cash proceeds of $1.44 billion from the contribution of the Propane Business. In 2011 we paid cash for acquisitions of $1.97 billion, primarily for the acquisition of LDH (the “LDH Acquisition”), and made net advances to our joint ventures of $205.6 million.

Growth capital expenditures for 2012, before changes in accruals, were $1.89 billion for our midstream, intrastate transportation and storage and NGL segments, $9.6 million for our interstate transportation segment, and $2.7 million for our retail propane and all other segments. We also incurred $81.2 million in maintenance capital expenditures, of which $50.5 million related to our midstream, intrastate transportation and storage and NGL segments, $25.1 million related to our interstate transportation segment and $5.6 million related to our retail propane and all other segments.

Growth capital expenditures for 2011, before changes in accruals, were $744.5 million for our midstream and intrastate transportation and storage segments, $133.7 million for our interstate transportation segment, and $26.9 million for our retail propane and all other segments. We also incurred $80.5 million in maintenance capital expenditures, of which $45.7 million related to our midstream and intrastate transportation and storage segments, $15.3 million related to our interstate transportation segment and $19.6 million related to our retail propane and all other segments.

Financing Activities

Changes in cash flows from financing activities between periods primarily result from changes in the levels of borrowings and equity issuances, which are primarily used to fund our acquisitions and growth capital expenditures. Distributions to partners increased between the periods as a result of increases in the number of Common Units outstanding.

Nine months ended September 30, 2012 compared to nine months ended September 30, 2011. Cash provided by financing activities during 2012 was $1.19 billion as compared to cash provided by financing activities of $2.16

billion for 2011. In 2012, we received net proceeds from Common Unit offerings of $771.8 million compared to $799.3 million in 2011. Net proceeds from the offerings were used to repay outstanding borrowings under the ETP Credit Facility, to fund capital expenditures, to fund capital contributions to joint ventures, as well as for general partnership purposes. During 2012, we had a net increase in our debt level of $1.20 billion as compared to a net increase of $1.64 billion for 2011, primarily due to our issuance of $2.00 billion in aggregate principal amount of senior notes in January 2012 to fund the Citrus Merger, partially offset by the repurchase of $750.0 million in aggregate principal amount of senior notes in connection with our tender offers announced in January 2012 (see Note 10 to our

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consolidated financial statements). In connection with the issuance of senior notes in January 2012, we incurred debt issuance costs of $18.1 million compared to $12.3 million in debt issuance costs in 2011 related to the issuance of senior notes in May 2011. We paid distributions of $959.6 million to our partners in 2012 as compared to $863.5 million in 2011. In addition, we received capital contributions of $240.1 million from Regency for its noncontrolling interest in Lone Star as compared to $616.3 million in 2011.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

| | September 30, 2012 | December 31, 2011 |
|---|---|---|
| ETP Credit Facility | $491,914 | $314,438 |
| ETP Senior Notes | 7,691,951 | 6,550,000 |
| Transwestern Senior Notes | 870,000 | 870,000 |
| HOLP Senior Notes | — | 71,314 |
| Other long-term debt | — | 10,345 |
| Unamortized discounts | (20,563) | (15,457) |
| Fair value adjustments related to interest rate swaps | 7,438 | 11,647 |
| Total debt | 9,040,740 | 7,812,287 |
| Less: current maturities | (350,000) | (424,117) |
| Long-term debt, less current maturities | $8,690,740 | $7,388,170 |

The terms of our consolidated indebtedness are described in more detail in our Annual Report on Form 10-K for the year ended December 31, 2011, filed with the SEC on February 22, 2012 and in Note 10 to our consolidated financial statements.

ETP as Co-Obligor of Sunoco Debt

In connection with the Sunoco Merger and Holdco Transaction, which was completed on October 5, 2012, ETP became a co-obligor on approximately $965 million of aggregate principal amount of Sunoco's existing senior notes and debentures.

ETP Credit Facility

The ETP Credit Facility is unsecured and is not guaranteed by any of the Partnership's subsidiaries and has equal rights to holders of our current and future unsecured debt. Indebtedness under the ETP Credit Facility has the same priority of payment as our other current and future unsecured debt.

As of September 30, 2012, we had $491.9 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.98 billion after taking into account letters of credit of $31.9 million. The weighted average interest rate on the total amount outstanding as of September 30, 2012 was 1.72%.

ETP used approximately $2.0 billion of Sunoco's cash on hand to partially fund the cash portion of the Sunoco Merger consideration. The remainder of the cash portion of the merger consideration, approximately $620 million, was funded with borrowings under the ETP Credit Facility.

Contingent Residual Support Agreement - AmeriGas

In order to finance the cash portion of the purchase price of the Propane Business described in Note 6, AmeriGas Finance LLC ("Finance Company"), a wholly owned subsidiary of AmeriGas, issued $550.0 million in aggregate principal amount of 6.75% Senior Notes due 2020 and $1.0 billion in aggregate principal amount of 7.00% Senior Notes due 2022. AmeriGas borrowed $1.5 billion of the proceeds of the Senior Notes issuance from Finance Company through an intercompany borrowing having maturity dates and repayment terms that mirror those of the Senior Notes (the "Supported Debt").

In connection with the closing of the contribution of the Propane Business, ETP entered into a Contingent Residual Support Agreement ("CRSA") with AmeriGas, Finance Company, AmeriGas Finance Corp. and UGI Corp., pursuant to which ETP will provide contingent, residual support of the Supported Debt, as defined in the CRSA.

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Covenants Related to Our Credit Agreements

We were in compliance with all requirements, tests, limitations, and covenants related to our credit agreements as of September 30, 2012.

Contractual Obligations

The following table summarizes our long-term debt and other contractual obligations as of September 30, 2012 (in thousands):

| | Payments Due by Period | | | | |
|---|---|---|---|---|---|
| Contractual Obligations | Total | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years |
| Long-term debt | $9,053,865 | $350,000 | $379,947 | $1,366,914 | $6,957,004 |
| Interest on long-term debt (a) | 7,273,721 | 112,326 | 1,079,152 | 942,992 | 5,139,251 |
| Payments on derivatives | 70,088 | (2,228) | 72,316 | — | — |
| Purchase commitments (b) | 190,374 | 179,416 | 10,958 | — | — |
| Operating lease obligations | 222,437 | 4,350 | 35,331 | 32,767 | 149,989 |
| Totals (c) | $16,810,485 | $643,864 | $1,577,704 | $2,342,673 | $12,246,244 |

(a) Interest payments on long-term debt are based on the principal amount of debt obligations as of September 30, 2012. With respect to variable rate debt, the interest payments were estimated using the interest rate as of September 30, 2012. To the extent interest rates change, our contractual obligations for interest payments will change. See "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for further discussion.

(b) We define a purchase commitment as an agreement to purchase goods or services that is enforceable and legally binding (unconditional) on us that specifies all significant terms, including: fixed or minimum quantities to be purchased; fixed, minimum or variable price provisions; and the approximate timing of the transactions. We have long and short-term product purchase obligations for propane and energy commodities with third-party suppliers. These purchase obligations are entered into at either variable or fixed prices. The purchase prices that we are obligated to pay under variable price contracts approximate market prices at the time we take delivery of the volumes. Our estimated future variable price contract payment obligations are based on the September 30, 2012 market price of the applicable commodity applied to future volume commitments. Actual future payment obligations may vary depending on market prices at the time of delivery. The purchase prices that we are obligated to pay under fixed price contracts are established at the inception of the contract. Our estimated future fixed price contract payment obligations are based on the contracted fixed price under each commodity contract. Obligations shown in the table represent estimated payment obligations under these contracts for the periods indicated.

(c) Excludes non-current deferred tax liabilities of $149.5 million due to uncertainty of the timing of future cash flows for such liabilities.

Cash Distributions

Under our Partnership Agreement, we will distribute to our partners within 45 days after the end of each calendar quarter, an amount equal to all of our Available Cash, as defined, for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements. Our commitment to our Unitholders is to distribute the increase in our cash flow while maintaining prudent reserves for our operations.

Following are distributions declared and/or paid by us subsequent to December 31, 2011:

| Quarter Ended | Record Date | Payment Date | Rate |
|---|---|---|---|
| December 31, 2011 | February 7, 2012 | February 14, 2012 | $0.89375 |
| March 31, 2012 | May 4, 2012 | May 15, 2012 | 0.89375 |
| June 30, 2012 | August 6, 2012 | August 14, 2012 | 0.89375 |
| September 30, 2012 | November 6, 2012 | November 14, 2012 | 0.89375 |

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The total amounts of distributions declared during the nine months ended September 30, 2012 and 2011 were as follows (all from Available Cash from our operating surplus and are shown in the period with respect to which they relate):

| | Nine Months Ended September 30, | |
|---|---|---|
| | 2012 | 2011 |
| Limited Partners: | | |
| Common Units | $693,089 | $560,281 |
| Class E Units | 9,363 | 9,363 |
| Class F Units [1] | 85,037 | — |
| General Partner interest | 14,768 | 14,690 |
| IDRs | 322,737 | 310,254 |
| Total distributions declared | $1,124,994 | $894,588 |

(1) Total distributions to be paid in November 2012 on the Class E and Class F units are $3.1 million and $85.0 million, respectively. All of the outstanding Class E and Class F units are held by subsidiaries of Holdco, which is 40% owned by ETP, subsequent to October 5, 2012.

In conjunction with the Citrus Merger, ETE agreed to relinquish its rights to $220 million of distributions associated with the IDRs from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters. In addition, under the terms of the Holdco transaction agreement, ETE will relinquish an aggregate of $210 million of incentive distributions over 12 consecutive quarters following the closing of the Holdco Transaction. The distributions reflected above for the nine months ended September 30, 2012 reflect IDR reductions totaling $58.8 million, which include three quarters of IDR relinquishment related to the Citrus Merger and one quarter related to the Holdco Transaction.

## Critical Accounting Policies

Disclosure of our critical accounting policies is included in our Annual Report on Form 10-K for the year ended December 31, 2011.

## ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended December 31, 2011, in addition to the accompanying notes and management’s discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Quarterly Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K for the year ended December 31, 2011. Since December 31, 2011, there have been no material changes to our primary market risk exposures or how those exposures are managed.

The United States Congress adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act (HR 4173), which, among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market. This legislation requires the Commodities Futures Trading Commission (the “CFTC”), the SEC, and other regulators to promulgate rules and regulations implementing the new legislation. On August 13, 2012, the CFTC and SEC published their joint, final rules further defining the term “swap” for purposes of the Dodd-Frank Act. The final swap definition rules became effective on October 12, 2012, which, in turn, triggered several other compliance dates. However, the CFTC's swaps and futures position limit rules, which were expected to become effective on October 12, 2012, were vacated in a federal District Court decision and will no longer be in effect until the CFTC issues and finalizes revised rules. At this time, there is no pending proposal and no anticipated compliance date for CFTC position limit rules. In addition, in early October 2012, the CFTC issued numerous statements extending and clarifying compliance dates, and, as a result, many regulations, particularly those associated with new entities such as swap dealers and major swap participants, will become effective on December 31, 2012. Among other things, the October 12, 2012 date triggers the start of certain reporting and recordkeeping rules, with full compliance phased in over an additional 180-day period depending on swap asset class and counterparty. It is expected that entities that are end users of swaps or otherwise are not swap dealers or major swap participants will be required to comply with the Dodd-Frank reporting and recordkeeping rules in April 2013. The financial reform legislation may also require us to comply with swaps margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. Furthermore, some standardized swaps derivatives traded on organized markets are anticipated to be converted to futures contracts;

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while such futures transactions will not be subject to swaps regulations, they will be subject to regulation as futures transactions. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

Commodity Price Risk

The table below summarizes our commodity-related financial derivative instruments and fair values as of September 30, 2012 and December 31, 2011, as well as the effect of an assumed hypothetical 10% change in the underlying price of the commodity. Notional volumes are presented in MMBtu for natural gas, thousand megawatt for power and gallons for propane. Dollar amounts are presented in thousands.

| | September 30, 2012 | | | December 31, 2011 | | |
|---|---|---|---|---|---|---|
| | Notional Volume | Fair Value Asset (Liability) | Effect of Hypothetical 10% Change | Notional Volume | Fair Value Asset (Liability) | Effect of Hypothetical 10% Change |
| Mark-to-Market Derivatives (Trading) | | | | | | |
| Natural Gas: | | | | | | |
| Basis Swaps IFERC/NYMEX [1] | (29,850,000) | $(10,528) | $ 261 | (151,260,000) | $(22,582) | $ 2,593 |
| Power: | | | | | | |
| Forwards | 230,000 | 311 | 186 | — | — | — |
| Futures | (14,500) | (231) | 59 | — | — | — |
| Options – Calls | 1,535,600 | 388 | 917 | — | — | — |
| (Non-Trading) | | | | | | |
| Natural Gas: | | | | | | |
| Basis Swaps IFERC/NYMEX | (8,057,500) | (1,347) | 11 | (61,420,000) | 4,024 | 266 |
| Swing Swaps IFERC | (18,827,500) | (658) | 541 | 92,370,000 | (1,072) | 138 |
| Fixed Swaps/Futures | (2,992,500) | (1,247) | 1,344 | 797,500 | (4,301) | 145 |
| Forward Physical Contracts | (7,505,500) | 141 | 2,933 | (10,672,028) | (13) | 1,118 |
| Options – Puts/Calls [2] | — | (236) | 169 | — | — | — |
| Propane: | | | | | | |
| Forwards/Swaps | — | — | — | 38,766,000 | (4,122) | 5,290 |
| Fair Value Hedging Derivatives (Non-Trading) | | | | | | |
| Natural Gas: | | | | | | |
| Basis Swaps IFERC/NYMEX | (20,670,000) | (449) | 120 | (28,752,500) | (808) | 181 |
| Fixed Swaps/Futures | (46,752,500) | (13,583) | 17,326 | (45,822,500) | 70,761 | 14,048 |
| Cash Flow Hedging Derivatives (Non-Trading) | | | | | | |
| Natural Gas: | | | | | | |
| Basis Swaps IFERC/NYMEX | (4,600,000) | (65) | 26 | — | — | — |
| Fixed Swaps/Futures | (11,900,000) | 1,876 | 4,333 | — | — | — |
| Options – Puts | 900,000 | 1,543 | 197 | 3,600,000 | 6,435 | 933 |
| Options – Calls | (900,000) | — | — | (3,600,000) | (12) | 13 |

(1) Includes aggregate amounts for open positions related to Houston Ship Channel, Waha Hub, NGPL TexOk, West Louisiana Zone and Henry Hub locations.

(2) Options were bought and sold at varying strike prices in offsetting volumes.

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The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information and appropriate valuation techniques. Non-trading positions offset physical exposures to the cash market; none of these offsetting physical exposures are included in the above tables. Price-risk sensitivities were calculated by assuming a theoretical 10% change (increase or decrease) in price regardless of term or historical relationships between the contractual price of the instruments and the underlying commodity price. Results are presented in absolute terms and represent a potential gain or loss in net income or in other comprehensive income. In the event of an actual 10% change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10% due to factors such as when the financial instrument settles and the location to which the financial instrument is tied (i.e., basis swaps) and the relationship between prompt month and forward months.

Interest Rate Risk

As of September 30, 2012, we had $491.9 million of floating rate debt outstanding under our revolving credit facility. A hypothetical change of 100 basis points would result in a change to interest expense of $4.9 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps. To the extent that we have debt with floating interest rates that are not hedged, our results of operations, cash flows and financial condition could be adversely affected by increases in interest rates.

We had the following interest rate swaps outstanding as of September 30, 2012 and December 31, 2011 (dollars in thousands), none of which are designated as hedges for accounting purposes:

| | | Notional Amount Outstanding | |
|---|---|---|---|
| Term | Type [1] | September 30, 2012 | December 31, 2011 |
| May 2012[2] | Forward starting to pay a fixed rate of 2.59% and receive a floating rate | $— | $350,000 |
| August 2012[2] | Forward starting to pay a fixed rate of 3.51% and receive a floating rate | — | 500,000 |
| July 2013[2] | Forward starting to pay a fixed rate of 4.02% and receive a floating rate | 400,000 | 300,000 |
| July 2014[2] | Forward starting to pay a fixed rate of 4.26% and receive a floating rate | 400,000 | — |
| July 2018 | Pay a floating rate plus a spread of 4.17% and receive a fixed rate of 6.70% | 600,000 | 500,000 |

(1) Floating rates are based on 3-month LIBOR.

(2) Represents the effective date. These forward starting swaps have a term of 10 years with a mandatory termination date the same as the effective date.

A hypothetical change of 100 basis points in interest rates for these interest rate swaps would result in a net change in the fair value of interest rate derivatives and earnings (recognized in gains and losses on non-hedged interest rate derivatives) of approximately $50.8 million as of September 30, 2012 and $82.7 million as of December 31, 2011. For the $600.0 million of interest rate swaps whereby we pay a floating rate and receive a fixed rate, a hypothetical change of 100 basis points in interest rates would result in a net change in annual cash flows (swap settlements) of $6.0 million. For the forward-starting interest rate swaps, a hypothetical change of 100 basis points in interest rates would not affect cash flows until the swaps are settled.

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 or multiple counterparties.

Our counterparties consist primarily of petrochemical companies and other industrials, small to major oil and gas producers, midstream and power generation companies. This concentration of counterparties may impact our 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. Currently, management does not anticipate a material adverse effect on our financial position or results of operations as a result of counterparty nonperformance.

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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.

## ITEM 4. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

We have established disclosure controls and procedures to ensure that information required to be disclosed by us, including our consolidated entities, in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms.

Under the supervision and with the participation of senior management, including the Chief Executive Officer ("Principal Executive Officer") and the Chief Financial Officer ("Principal Financial Officer") of our General Partner, we evaluated our disclosure controls and procedures, as such term is defined under Rule 13a–15(e) promulgated under the Exchange Act. Based on this evaluation, the Principal Executive Officer and the Principal Financial Officer of our General Partner concluded that our disclosure controls and procedures were effective as of September 30, 2012 to ensure that information required to be disclosed by us in the reports we file or submit under the Exchange Act (1) is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and (2) is accumulated and communicated to management, including the Principal Executive Officer and Principal Financial Officer of our General Partner, to allow timely decisions regarding required disclosure.

### Changes in Internal Control over Financial Reporting

There have been no changes in our internal controls over financial reporting (as defined in Rule 13(a)-15(f) or Rule 15d-15(f) of the Exchange Act) during the three months ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

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PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended December 31, 2011 and Note 13 – Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Quarterly Report on Form 10-Q for the quarter ended September 30, 2012.

ITEM 1A. RISK FACTORS

Our recently completed Sunoco Merger presents several risks to our operating performance going forward. Some risks are similar to the risks associated with our existing business that have recently been disclosed. However, certain of those risks represent new risks related to our business or existing risks that have become more significant. The following risk factors should be read in conjunction with our risk factors described in "Part I — Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2011 and "Part II — Item 1A. Risk Factors" of our Quarterly Report on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012.

Risks Relating to Sunoco and Sunoco Logistics

As a result of Sunoco's exit from the refining business, Sunoco is entirely dependent upon third parties for the supply of refined products such as gasoline and diesel for its retail marketing business.

As a result of Sunoco's exit from the refining business, Sunoco is required to purchase refined products from third party sources, including the joint venture that acquired Sunoco's Philadelphia refinery. Sunoco may also need to contract for new ships, barges, pipelines or terminals which Sunoco has not historically used to transport these products to its markets. The inability to acquire refined products and any required transportation services at prices no less favorable than the market-based transfer price between Sunoco's refining and supply and retail marketing business segments or the failure of Sunoco's suppliers to deliver product in accordance with Sunoco's supply agreements may have a material adverse impact on Sunoco's business or results of operations.

The adoption of derivatives legislation by the United States Congress could have an adverse effect on Sunoco's ability to hedge risks associated with its business.

Sunoco uses swaps, options, futures, forwards and other derivative instruments to hedge a variety of commodity price risks and to achieve ratable pricing of crude oil purchases, to convert certain expected refined product sales to fixed or floating prices, to lock in what Sunoco considers to be acceptable margins for various refined products and to lock in the price of a portion of Sunoco's electricity and natural gas purchases or sales and transportation costs. Sunoco does not hold or issue derivative instruments for speculative purposes. The United States Congress recently adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as Sunoco, that participate in that market. The new legislation was signed into law by the President on July 21, 2010, and required the Commodities Futures Trading Commission, or CFTC, and the United States Securities and Exchange Commission, or SEC, to promulgate rules and regulations implementing the new legislation. The CFTC also has proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require Sunoco to comply with margin requirements in connection with its derivative activities, although the application of those provisions to Sunoco is uncertain at this time. The financial reform legislation also requires many counterparties to Sunoco's derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could significantly increase the cost of derivative contracts (including requirements to post collateral, which could adversely affect Sunoco's available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks Sunoco encounters, reduce Sunoco's ability to monetize or restructure its existing derivative contracts, and increase its exposure to less creditworthy counterparties. If Sunoco reduces its use of derivatives as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Sunoco's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on Sunoco, its financial condition, and its results of operations.

Sunoco depends upon Sunoco Logistics for a substantial portion of the logistics network that serves its refineries.

We indirectly owns a 2% general partner interest in Sunoco Logistics, as well as all of the incentive distribution rights and a 32.4% limited partner interest in Sunoco Logistics. Sunoco Logistics owns and operates refined product and crude oil pipelines and terminals and conducts crude oil and refined product acquisition and marketing activities. Sunoco Logistics generates revenues by charging tariffs for transporting petroleum products and crude oil through its pipelines, by charging fees for terminalling and storing refined products and crude oil and by purchasing and selling crude oil and refined products. Sunoco Logistics serves Sunoco's refineries under long-term pipelines and terminals, storage and throughput agreements.

The business of Sunoco Logistics is subject to a variety of operating and regulatory risks.

Sunoco Logistics is subject to operating and regulatory risks, including, but not limited to:

- its reliance on its significant customers, including Sunoco;
- competition from other pipelines;
- environmental regulations affecting pipeline operations;
- operational hazards and risks;
- pipeline tariff regulations affecting the rates it can charge;
- limitations on additional borrowings and other restrictions due to its debt covenants; and
- other financial, operational and legal risks.

The occurrence of any of these risks could directly or indirectly affect Sunoco Logistics', as well as our financial condition, results of operations and cash flows.

A material decrease in demand or distribution of crude oil or refined products available for transport through Sunoco Logistics' pipelines or terminal facilities could materially and adversely affect our, results of operations and cash flows.

The volume of crude oil transported through Sunoco Logistics' crude oil pipelines and terminal facilities depends on the availability of attractively priced crude oil produced or received in the areas serviced by its assets. A period of sustained crude oil price declines could lead to a decline in drilling activity, production and import levels in these areas. Similarly, a period of sustained increases in the price of crude oil supplied from any of these areas, as compared to alternative sources of crude oil available to Sunoco's customers, could materially reduce demand for crude oil in these areas. In either case, the volumes of crude oil transported in Sunoco Logistics' crude oil pipelines and terminal facilities could decline, and it could likely be difficult to secure alternative sources of attractively priced crude oil supply in a timely fashion or at all.

Similarly, a decrease in market demand for refined products could also impact throughput at Sunoco Logistics' pipelines and terminals. Material factors that could lead to a sustained decrease in market demand for refined products include a sustained recession or other adverse economic condition that results in lower purchases of refined petroleum products, higher refined products prices due to an increase in the market price of crude oil, changes in economic conditions or other factors, higher fuel taxes or other governmental or regulatory actions that increase, directly or indirectly, the cost of gasoline or other refined products or a shift by consumers to more fuel-efficient or alternative fuel vehicles or an increase in fuel economy.

If Sunoco Logistics is unable to replace any significant volume declines with additional volumes from other sources, our results of operations and cash flows could be materially and adversely affected.

Rate regulation or market conditions may not allow Sunoco Logistics to recover the full amount of increases in the costs of its pipeline operations. A successful challenge to Sunoco Logistics' pipeline rates could materially and adversely affect our results of operations and cash flows.

Interstate common carrier pipeline operations are subject to rate regulation by the FERC under the Interstate Commerce Act, the Energy Policy Act of 1992, and related rules and orders. The Interstate Commerce Act requires that tariff rates for petroleum pipelines be “just and reasonable” and not unduly discriminatory. This statute also permits interested persons to challenge proposed new or changed rates and authorizes the FERC to suspend the effectiveness of such rates for up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund revenues in excess of the prior tariff during the term of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

The primary ratemaking methodology used by the FERC to authorize increases in the tariff rates of petroleum pipelines is price indexing. If the rate changes allowed under the indexing methodology are not large enough to fully reflect actual increases to Sunoco Logistics pipeline costs, its financial condition and Sunoco's could be adversely affected. If applying the index methodology results in a rate increase that is substantially in excess of the pipeline's actual cost increases, or it results in a rate decrease that is substantially less than the pipeline's actual cost decrease, Sunoco Logistics may be required to reduce its pipeline rates. The FERC's ratemaking methodologies may limit Sunoco Logistics' ability to set rates based on its costs or may delay the use of rates that reflect increased costs. In addition, if the FERC's indexing methodology changes, the new methodology could materially and adversely affect Sunoco Logistics' and Sunoco's financial condition, results of operations or cash flows.

Under the Energy Policy Act adopted in 1992, certain interstate pipeline rates were deemed just and reasonable or “grandfathered.” Revenues are derived from such grandfathered rates on most of Sunoco Logistics' FERC-regulated pipelines. A person challenging a grandfathered rate must, as a threshold matter, establish a substantial change since the date of enactment of the Energy Policy Act, in either the economic circumstances or the nature of the service that formed the basis for the rate. If the FERC were to find a substantial change in circumstances, then the existing rates could be subject to detailed review and there is a risk that some rates could be found to be in excess of levels justified by the pipeline's costs. In such event, the FERC could order Sunoco Logistics to reduce pipeline rates prospectively and to pay refunds to shippers.

In addition, a state commission could also investigate Sunoco Logistics' intrastate pipeline rates or terms and conditions of service on its own initiative or at the urging of a shipper or other interested party. If a state commission found that such pipeline rates exceeded levels justified by Sunoco Logistics' costs, the state commission could order a reduction in the rates.

Any reduction in the capability of Sunoco Logistics' shippers to utilize either its pipelines or interconnecting third-party pipelines could cause a reduction of volumes transported in Sunoco Logistics' pipelines and through its terminals.

Sunoco and the other users of Sunoco Logistics' pipelines and terminals are dependent upon those pipelines, as well as connections to third-party pipelines, to receive and deliver crude oil and refined products. Any interruptions or reduction in the capabilities of Sunoco Logistics' pipelines or these interconnecting pipelines due to testing, line repair, reduced operating pressures, or other causes would result in reduced volumes transported in Sunoco Logistics' pipelines or through its terminals. Similarly, if additional shippers begin transporting volume over interconnecting pipelines, the allocations to Sunoco Logistics' existing shippers on these interconnecting pipelines could be reduced, which also could reduce volumes transported in its pipelines or through its terminals. Allocation reductions of this nature are not infrequent and are beyond Sunoco Logistics' control. Any such interruptions or allocation reductions that, individually or in the aggregate, are material or continue for a sustained period of time could have a material adverse effect on Sunoco Logistics' results of operations, financial position, or cash flows.

Sunoco Logistics does not own all of the land on which its pipelines and terminal facilities are located and Sunoco does not own all of the land on which its direct retail service stations are located, and Sunoco leases certain facilities and equipment, and Sunoco is subject to the possibility of increased costs to retain necessary land use which could disrupt Sunoco's operations.

Sunoco Logistics does not own all of the land on which certain of its pipelines and terminal facilities are located and Sunoco does not own all of the land on which its retail service stations are located, and, therefore, Sunoco and Sunoco Logistics are subject to the risk of increased costs to maintain necessary land use. Sunoco Logistics obtains the rights to construct and operate certain of its pipelines and related facilities on land owned by third parties and governmental agencies for a specific period of time. The loss of these rights, through its inability to renew right-of-way contracts on acceptable terms or increased costs to renew such rights, could have a material adverse effect on Sunoco Logistics and Sunoco's financial condition, results of operations and cash flows. Whether Sunoco Logistics has the power of eminent domain for its pipelines varies from state to state, depending upon the type of pipeline (e.g., crude oil or refined products) and the laws of the particular state. In either case, Sunoco Logistics must compensate landowners for the use of their property and, in eminent domain actions, such compensation may be determined by a court. The inability to exercise the power of eminent domain could negatively affect Sunoco Logistics' business if it was to lose the right to use or occupy the property on which its pipelines are located. Sunoco also has rental agreements for approximately 29% of the company- or dealer-operated retail service stations where Sunoco currently controls the real estate and Sunoco Logistics has rental agreements for certain logistics facilities. As such, both Sunoco and Sunoco

Logistics are subject to the possibility of increased costs under rental agreements with landowners, primarily through rental increases and renewals of expired agreements. Sunoco is also subject to the risk that such agreements may not be renewed. Additionally, certain facilities and equipment (or parts thereof) used by Sunoco are leased from third parties for specific periods. Sunoco's inability to renew equipment leases or otherwise maintain the right to utilize such facilities and equipment on acceptable terms, or the increased costs to maintain such rights, could have a material adverse effect on Sunoco's results of operations and cash flows.

Governmental regulations and policies, particularly in the areas of taxation, energy and the environment, have a significant impact on Sunoco's activities.

Federally mandated standards for use of renewable biofuels, such as ethanol and biodiesel in the production of refined products, are transforming traditional gasoline and diesel markets in North America. These regulatory mandates present production and logistical challenges for both the petroleum refining and ethanol industries, and may require additional capital expenditures or expenses by Sunoco. Sunoco may have to enter into arrangements with other parties to meet its obligations to use advanced biofuels, with potentially uncertain supplies of these new fuels. If Sunoco is unable to obtain or maintain sufficient quantities of ethanol to support its blending needs, its sale of ethanol blended gasoline could be interrupted or suspended which could result in lower profits. There also will be compliance costs related to these regulations. Sunoco may experience a decrease in demand for refined petroleum products due to new federal requirements for increased fleet mileage per gallon or due to replacement of refined petroleum products by renewable fuels. In addition, tax incentives and other subsidies making renewable fuels more competitive with refined petroleum products may reduce refined petroleum product margins and the ability of refined petroleum products to compete with renewable fuels. A structural expansion of production capacity for such renewable biofuels could lead to significant increases in the overall production, and available supply, of gasoline and diesel in markets that Sunoco supplies. This potential increase in supply of gasoline and diesel could result in lower refining margins for us, particularly in the event of a contemporaneous reduction in demand, or during periods of sustained low demand for such refined products. In addition, a significant shift by consumers to more fuel-efficient vehicles or alternative fuel vehicles (such as ethanol or wider adoption of gas/electric hybrid vehicles), or an increase in vehicle fuel economy, whether as a result of technological advances by manufacturers, legislation mandating or encouraging higher fuel economy or the use of alternative fuel, or otherwise, also could lead to a decrease in demand, and reduced margins, for the refined petroleum products that Sunoco markets and sells.

It is possible that any, or a combination, of these occurrences could have a material adverse effect on Sunoco's business or results of operations.

Sunoco is subject to numerous environmental laws and regulations that require substantial expenditures and affect the way Sunoco operates, which could affect its business, future operating results or financial position in a materially adverse way.

Sunoco is subject to extensive federal, state and local laws and regulations, including those relating to the protection of the environment, waste management, discharge of hazardous materials, and the characteristics and composition of refined products. Certain of these laws and regulations also impose obligations to conduct assessment or remediation efforts at Sunoco's facilities as well as at formerly owned properties or third-party sites where Sunoco has taken wastes for disposal. Environmental laws and regulations may impose liability on Sunoco for the conduct of third parties, or for actions that complied with applicable requirements when taken, regardless of negligence or fault. Environmental laws and regulations are subject to frequent change, and often become more stringent over time. Of particular significance to Sunoco are:

- Greenhouse gas emissions: Through the operation of Sunoco's refineries and marketing facilities, Sunoco's operations emit greenhouse gases, or GHG, including carbon dioxide. There are various legislative and regulatory measures to address monitoring, reporting or restriction of GHG emissions that are in various stages of review, discussion or implementation. These include federal and state actions to develop programs for the reduction of GHG emissions as well as proposals that would create a cap and trade system that would require Sunoco to purchase carbon emission allowances for emissions at Sunoco's manufacturing facilities and emissions caused by the use of the fuels that Sunoco sells. In response to findings that emissions of GHGs present an endangerment to public health and the environment, the United States Environmental Protection Agency, or EPA, has adopted regulations under existing provisions of the federal Clean Air Act that require a reduction in emissions of GHGs from motor vehicles and also may trigger construction and operating permit review for GHG emissions from certain stationary sources. The EPA has asserted that the final motor vehicle GHG emission standards triggered Prevention of Significant Deterioration, or PSD, and Title V permit requirements for stationary sources, commencing when the motor vehicle standards took effect on January 2, 2011. The EPA has published its final rule to address the permitting of GHG emissions from stationary sources under the PSD and Title V permitting programs, pursuant to which these permitting programs have been “tailored” to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. It is anticipated that facilities required to obtain PSD permits for their GHG emissions also will be required to reduce those emissions according to “best available control technology” standards for GHG that have yet to be developed. These EPA rulemakings could adversely affect Sunoco's operations and restrict or delay Sunoco's ability to obtain air permits for new or modified facilities. In addition, the EPA published a final rule in October 2009 requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including petroleum refineries, on an annual basis beginning in 2011 for emissions occurring after January 1, 2010. Moreover, the United States Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one-half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as petroleum refineries, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from Sunoco's equipment and operations could require Sunoco to incur costs to reduce emissions of GHGs associated with Sunoco's operations or could adversely affect demand for the refined petroleum products that Sunoco produces and markets.

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Sunoco is also subject to liabilities resulting from its current and past operations, including legal and administrative proceedings related to product liability, contamination from refining operations, past disposal practices, mercury mining, leaks from pipelines and underground storage tanks, premises-liability claims, allegations of exposures of third parties to toxic substances and general environmental claims. Legacy sites include inactive or formerly owned terminals and other logistics assets, divested retail sites, refineries, mercury mines and chemical plants. Resolving such liabilities may result in the assessment of sanctions requiring the payment of monetary fines and penalties, incurrence of costs to conduct corrective actions or pursue investigatory and remedial activities, payment of damages in settlement of claims and suits, and issuance of injunctive relieve or orders that could limit some or all of Sunoco's operations and have a material adverse effect on Sunoco's business or results of operations. Although Sunoco has established financial reserves for its environmental liabilities, ongoing remediation activities may result in the discovery of additional contamination which may increase environmental remediation liabilities. Accordingly, we cannot guarantee that current reserves will be adequate to cover all future liabilities even for currently known contamination.

Compliance with current and future environmental laws and regulations could require Sunoco to make significant expenditures, increasing the overall cost of operating its businesses, including capital costs to construct, maintain and upgrade equipment and facilities. To the extent these expenditures are not ultimately reflected in the prices of Sunoco's products or services, Sunoco's operating results would be adversely affected. Sunoco's failure to comply with these laws and regulations could also result in substantial fines or penalties against Sunoco or orders that could limit Sunoco's operations and have a material adverse effect on its business or results of operations.

Certain federal and state government regulators have sought compensation from companies like Sunoco for natural resource damages as an adjunct to remediation programs. Because Sunoco is involved in a number of remediation sites, a substantial increase in natural resource damage claims at such remedial sites could result in substantially increased costs to Sunoco.

Sunoco Logistics' business is subject to federal, state and local laws and regulations that govern the product quality specifications of the petroleum products that Sunoco Logistics stores and transports.

The petroleum products that Sunoco Logistics stores and transports are sold by its customers for consumption into the public market. Various federal, state and local agencies have the authority to prescribe specific product quality specifications to commodities sold into the public market. Changes in product quality specifications could reduce Sunoco Logistics' throughput volume, require Sunoco Logistics to incur additional handling costs or require the expenditure of significant capital. In addition, different product specifications for different markets impact the fungibility of products transported and stored in Sunoco Logistics' pipeline systems and terminal facilities and could require the construction of additional storage to segregate products with different specifications. Sunoco Logistics may be unable to recover these costs through increased revenues.

In addition, the operations of Sunoco Logistics' butane blending services are reliant upon gasoline vapor pressure specifications. Significant changes in such specifications could reduce butane blending opportunities, which would affect Sunoco Logistics' ability to market its butane blending services licenses.

Product liability claims and litigation could adversely affect Sunoco's business and results of operations.

Product liability is a significant commercial risk. Substantial damage awards have been made in certain jurisdictions against manufacturers and resellers based upon claims for injuries caused by the use of or exposure to various products. There can be no assurance that product liability claims against Sunoco would not have a material adverse effect on Sunoco's business or results of operations.

Along with other refiners, manufacturers and sellers of gasoline, Sunoco is a defendant in numerous lawsuits that allege methyl tertiary butyl ether, or MTBE, contamination in groundwater. Plaintiffs, who include water purveyors and municipalities responsible for supplying drinking water and private well owners, are seeking compensatory damages (and in some cases injunctive relief, punitive damages and attorneys' fees) for claims relating to the alleged manufacture and distribution of a defective product (MTBE-containing gasoline) that contaminates groundwater, and general allegations of product liability, nuisance, trespass, negligence, violation of environmental laws and deceptive business practices. There has been insufficient information developed about the plaintiffs' legal theories or the facts that would be relevant to an analysis of the ultimate liability to Sunoco. These allegations or other product liability claims against Sunoco could have a material adverse effect on Sunoco's business or results of operations.

Federal and state legislation and/or regulation could have a significant impact on market conditions and/or adversely affect Sunoco's business and results of operations.

From time to time, new legislation or regulations are adopted by the federal government and various states or other regulatory bodies. Any such federal or state legislation or regulations, including but not limited to any potential environmental rules and regulations, tax legislation, energy policy legislation or legislation affecting trade or commercial practices, could have a significant impact on market conditions and could adversely affect Sunoco's business or results of operations in a material way.

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Disputes under long-term contracts could affect Sunoco's business and future operations in a materially adverse way.
Sunoco has numerous long-term contractual arrangements across Sunoco's businesses that frequently include complex provisions. Interpretation of these provisions may, at times, lead to disputes with customers and/or suppliers. Unfavorable resolutions of these disputes could have a significant adverse effect on Sunoco's business and results of operations.

Sunoco Logistics faces strong competition.

Sunoco Logistics also faces strong competition in the market for the sale of retail gasoline and merchandise. Sunoco's competitors include service stations operated by fully integrated major oil companies and other well-recognized national or regional retail outlets, often selling gasoline or merchandise at aggressively competitive prices.

Pipeline operations of Sunoco Logistics face significant competition from other pipelines for large volume shipments. These operations also face competition from trucks for incremental and marginal volumes in areas served by Sunoco Logistics' pipelines. Sunoco Logistics' refined product terminals compete with terminals owned by integrated petroleum companies, refining and marketing companies, independent terminal companies and distribution companies with marketing and trading operations.

The actions of Sunoco's competitors, including the impact of foreign imports, could lead to lower prices or reduced margins for the products Sunoco sells, which could have an adverse effect on Sunoco's business or results of operations.

Sunoco is exposed to the credit and other counterparty risk of its customers in the ordinary course of its business.

Sunoco has various credit terms with virtually all of its customers, and its customers have varying degrees of creditworthiness. Although Sunoco evaluates the creditworthiness of each of its customers, Sunoco may not always be able to fully anticipate or detect deterioration in their creditworthiness and overall financial condition, which could expose Sunoco to an increased risk of nonpayment or other default under its contracts and other arrangements with them. In the event that a material customer or customers default on their payment obligations to Sunoco, this could materially adversely affect Sunoco's financial condition, results of operations or cash flows.

Sunoco has various credit agreements and other financing arrangements that impose certain restrictions on Sunoco and may limit Sunoco's flexibility to undertake certain types of transactions. If Sunoco fails to comply with the terms and provisions of its debt instruments, the indebtedness under them may become immediately due and payable, which could have a material adverse effect on Sunoco's financial position.

Several of Sunoco's existing debt instruments and financing arrangements contain restrictive covenants and that limit Sunoco's financial flexibility and that of its subsidiaries. Sunoco's credit facilities require the maintenance of collateral and certain financial ratios, satisfaction of certain financial condition tests and, subject to certain exceptions, impose restrictions on:

- incurrence of additional indebtedness;
- issuance of preferred stock by Sunoco's subsidiaries;
- incurrence of liens;
- sale and leaseback transactions;
- agreements by Sunoco's subsidiaries, which would limit their ability to pay dividends, make distributions or repay loans or advances to Sunoco; and
- fundamental changes, such as certain mergers and dispositions of assets.

Sunoco Logistics has credit facilities which also contain certain covenants. Increased borrowings by Sunoco Logistics will raise the level of Sunoco's total consolidated net indebtedness, and could restrict Sunoco's ability to borrow money or otherwise incur additional debt. If Sunoco does not comply with the covenants and other terms and provisions of its credit facilities, Sunoco will be required to request a waiver under, or an amendment to, those facilities. If Sunoco cannot obtain such a waiver or amendment, or if Sunoco fails to comply with the covenants and other terms and provisions of Sunoco's indentures, Sunoco would be in default under its debt instruments. Any defaults may cause the indebtedness under the facilities to become immediately due and payable, which could have a material adverse effect on Sunoco's financial position.

Sunoco's ability to meet its debt service obligations depends upon its future performance, which is subject to general economic conditions, industry cycles and financial, business and other factors affecting its operations, many of which are beyond Sunoco's control. A portion of Sunoco's cash flow from operations is needed to pay the principal of, and interest on, Sunoco's indebtedness and is not available for other purposes. If Sunoco is unable to generate sufficient cash flow from operations, Sunoco may have to

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sell assets, refinance all or a portion of its indebtedness or obtain additional financing. Any of these actions could have a material adverse effect on Sunoco's financial position.

The tax treatment of Sunoco Logistics depends on its status as a partnership for federal income tax purposes, as well as not being subject to a material amount of entity level taxation by individual states. If the IRS treats Sunoco Logistics as a corporation or it becomes subject to a material amount of entity level taxation for state tax purposes, it would substantially reduce the amount of cash available for distribution to its unitholders.

The anticipated after-tax economic benefit of our investment in the common units of Sunoco Logistics depends largely on Sunoco Logistics being treated as a partnership for federal income tax purposes. Sunoco Logistics has not requested, and does not plan to request, a ruling from the IRS on this matter. The IRS may adopt positions that differ from the ones Sunoco Logistics has taken. A successful IRS contest of the federal income tax positions Sunoco Logistics takes may impact adversely the market for its common units, and the costs of any IRS contest will reduce Sunoco Logistics' cash available for distribution to its unitholders. If Sunoco Logistics was treated as a corporation for federal income tax purposes, it would pay federal income tax at the corporate tax rate, and likely would pay state income tax at varying rates. Distributions to its unitholders generally would be subject to tax again as corporate distributions. Treatment of Sunoco Logistics as a corporation would result in a material reduction in its anticipated cash flow and after-tax return to its unitholders. Current law may change so as to cause Sunoco Logistics to be treated as a corporation for federal income tax purposes or to otherwise subject it to a material level of entity level taxation. States are evaluating ways to subject partnerships to entity level taxation through the imposition of state income, franchise and other forms of taxation. If any of these states were to impose a tax on Sunoco Logistics, the cash available for distribution to its unitholders would be reduced.

The tax treatment of publicly traded partnerships or our investment in Sunoco Logistics' common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.

The present federal income tax treatment of publicly traded partnerships, including Sunoco Logistics, or our investment in its common units, may be modified by administrative, legislative or judicial interpretation at any time. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. Moreover, any such modification could make it more difficult or impossible for Sunoco Logistics to meet the exception which allows publicly traded partnerships that generate qualifying income to be treated as partnerships (rather than corporations) for U.S. federal income tax purposes, affect or cause Sunoco Logistics to change its business activities, or affect the tax consequences of our investment in Sunoco Logistics' common units. For example, members of the United States Congress have been considering substantive changes to the definition of qualifying income and the treatment of certain types of income earned from partnerships. We are unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any such changes could negatively impact the value of our investment in Sunoco Logistics' common units.

Poor performance in the financial markets could have a material adverse effect on the level of funding of Sunoco's pension obligations, on the level of pension expense and on Sunoco's financial position. In addition, any use of current cash flow to fund Sunoco's pension could have a significant adverse effect on Sunoco's financial position.

Sunoco has substantial benefit obligations in connection with its noncontributory defined benefit pension plans. Sunoco has made contributions to the plans over the past several years to improve their funded status, and Sunoco expects to make additional contributions to the plans in the future as well. The projected benefit obligation of Sunoco's funded defined benefit plans at December 31, 2011 exceeded the market value of Sunoco's plan assets by $160 million. Sunoco expects that upon its exit from the refining business, defined benefit pension plans will be frozen for all participants and no additional benefits will be earned. As a result of the workforce reduction, divestments and the shutdown of Sunoco's Eagle Point refinery, Sunoco incurred noncash settlement and curtailment losses and special termination benefits in these plans during 2011, 2010 and 2009 totaling approximately $60, $55 and $130 million pretax, respectively. Sunoco expects to incur additional settlement losses related to the exit from the refining business. In 2010, Sunoco contributed $234 million to its funded defined benefit plans consisting of $144 million of cash and 3.59 million shares of Sunoco common stock valued at $90 million. Poor performance of the financial markets, or decreases in interest rates, could result in additional significant charges to shareholders' equity and additional significant increases in future pension expense and funding requirements. To the extent that Sunoco has to fund its pension obligations with cash from operations, Sunoco may be at a disadvantage to some of its competitors who do not have the same level of obligations that Sunoco has.

A portion of Sunoco's workforce is unionized, and Sunoco may face labor disruptions that could materially and adversely affect its operations.

A portion of Sunoco's workforce is covered by a number of collective bargaining agreements with various terms and dates of expirations. There can be no assurances that Sunoco will not experience a work stoppage in the future as a result of labor disagreements. A labor disturbance at any of Sunoco's major facilities could have a material adverse effect on Sunoco's operations.

Sunoco has outsourced various functions to third-party service providers, which decreases its control over the performance of these functions. Disruptions or delays at Sunoco's third-party outsourcing partners could result in increased costs, or may adversely affect service levels and Sunoco's public reporting. Fraudulent activity or misuse of proprietary data involving our outsourcing partners could expose Sunoco to additional liability.

As part of Sunoco's long-term strategy, Sunoco is continually looking for opportunities to provide essential business services in a more cost-effective manner. In some cases, this requires the outsourcing of functions or parts of functions that can be performed more effectively by external service providers. Sunoco has previously outsourced various functions to third parties and expect to continue this practice with other functions in the future.

While outsourcing arrangements may lower Sunoco's cost of operations, they also reduce Sunoco's direct control over the services rendered. It is uncertain what effect such diminished control will have on the quality or quantity of products delivered or services rendered, on Sunoco's ability to quickly respond to changing market conditions, or on Sunoco's ability to ensure compliance with all applicable domestic and foreign laws and regulations. Sunoco believes that it conducts appropriate due diligence before entering into agreements with its outsourcing partners. Sunoco relies on its outsourcing partners to provide services on a timely and effective basis. Although Sunoco continuously monitors the performance of these third parties and maintains contingency plans in case they are unable to perform as agreed, Sunoco does not ultimately control the performance of its outsourcing partners. Much of Sunoco's outsourcing takes place in developing countries and, as a result, may be subject to geopolitical uncertainty. The failure of one or more of Sunoco's third-party outsourcing partners to provide the expected services on a timely basis at the prices Sunoco expects, or as required by contract, due to events such as regional economic, business, environmental or political events, information technology system failures, or military actions, could result in significant disruptions and costs to Sunoco's operations, which could materially adversely affect Sunoco's business, financial condition, operating results and cash flow and Sunoco's ability to file its financial statements with the SEC in a timely or accurate manner.

Sunoco's failure to generate significant cost savings from these outsourcing initiatives could adversely affect its profitability and weaken its competitive position. Additionally, if the implementation of Sunoco's outsourcing initiatives is disruptive to its business, Sunoco could experience transaction errors, processing inefficiencies, and the loss of sales and customers, which could cause its business and results of operations to suffer.

As a result of these outsourcing initiatives, more third parties are involved in processing Sunoco's information and data. Breaches of Sunoco's security measures or the accidental loss, inadvertent disclosure or unapproved dissemination of proprietary information or sensitive or confidential data about Sunoco or its clients, including the potential loss or disclosure of such information or data as a result of fraud or other forms of deception, could expose Sunoco to a risk of loss or misuse of this information, result in litigation and potential liability for Sunoco, lead to reputational damage to Sunoco brand, increase Sunoco's compliance costs, or otherwise harm Sunoco's business.

Sunoco's operations could be disrupted if Sunoco's information systems fail, causing increased expenses and loss of sales.

Sunoco's business is highly dependent on financial, accounting and other data processing systems and other communications and information systems, including its enterprise resource planning tools. Sunoco processes a large number of transactions on a daily basis and relies upon the proper functioning of computer systems. If a key system was to fail or experience unscheduled downtime for any reason, even if only for a short period, Sunoco's operations and financial results could be affected adversely. Sunoco's systems could be damaged or interrupted by a security breach, fire, flood, power loss, telecommunications failure or similar event. Sunoco has a formal disaster recovery plan in place, but this plan may not entirely prevent delays or other complications that could arise from an information systems failure. Sunoco's business interruption insurance may not compensate it adequately for losses that may occur.

Security breaches and other disruptions could compromise Sunoco Logistics' information and expose Sunoco Logistics to liability, which would cause its business and reputation to suffer.

In the ordinary course of Sunoco Logistics' business, Sunoco Logistics collects and stores sensitive data, including intellectual property, its proprietary business information and that of its customers, suppliers and business partners, and personally identifiable information of its employees, in Sunoco Logistics' data centers and on its networks. The secure processing, maintenance and transmission of this information is critical to Sunoco Logistics' operations and business strategy. Despite Sunoco Logistics' security measures, its information technology and infrastructure may be vulnerable to attacks by hackers or breached due to employee error, malfeasance or other disruptions. Any such breach could compromise Sunoco Logistics' networks and the information stored there could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties for divulging shipper information, disruption of Sunoco Logistics' operations, damage to its reputation, and loss of confidence in its products and services, which could adversely affect its business.

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ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

(a) Exhibits

The exhibits listed on the following Exhibit Index are filed as part of this Report. Exhibits required by Item 601 of Regulation S-K, but which are not listed below, are not applicable.

| | Exhibit Number | Description |
|---|---|---|
| (*) | 31.1 | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| (*) | 31.2 | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| (**) | 32.1 | Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| (**) | 32.2 | Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| (*) | 101 | Interactive data files pursuant to Rule 405 of Regulation S-T: (i) our Consolidated Balance Sheets as of September 30, 2012 and December 31, 2011; (ii) our Consolidated Statements of Operations for the three and nine months ended September 30, 2012 and 2011; (iii) our Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2012 and 2011; (iv) our Consolidated Statement of Partners' Capital for the nine months ended September 30, 2012; (v) our Consolidated Statements of Cash Flows for the nine months ended September 30, 2012 and 2011; and (vi) the notes to our Consolidated Financial Statements. |

* Filed herewith.

** Furnished herewith.

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SIGNATURE

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 thereunto duly authorized.

| | |
|---|---|
| | ENERGY TRANSFER PARTNERS, L.P. |
| | By: Energy Transfer Partners GP, L.P., its General Partner |
| | By: Energy Transfer Partners, L.L.C., its General Partner |
| Date: November 8, 2012 | By: /s/ Martin Salinas, Jr.<br>Martin Salinas, Jr.<br>Chief Financial Officer (duly authorized to sign on behalf of the registrant) |