Energy Transfer Partners, L.P.
Form 10-Q
November 07, 2011
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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, 2011
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 (state or other jurisdiction of incorporation or organization)	73-1493906 (I.R.S. Employer 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 November 2, 2011, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	209,592,014	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" or the "Partnership") 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, 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 Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011, as well as "Part I — Item 1A. Risk Factors" in the Partnership's Report on Form 10-K for the year ended December 31, 2010 filed with the Securities and Exchange Commission ("SEC") on February 28, 2011.

Definitions

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

/d	per day
Bbls	barrels
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
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
Mcf	thousand cubic feet
MMBtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange

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

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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, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$136,233	$49,540
Marketable securities	3,151	2,032
Accounts receivable, net of allowance for doubtful accounts of $6,577 and $6,409 as of September 30, 2011 and December 31, 2010, respectively	545,829	503,129
Accounts receivable from related companies	76,897	53,866
Inventories	306,895	362,058
Exchanges receivable	15,523	21,823
Price risk management assets	11,216	13,706
Other current assets	141,426	115,269
Total current assets	1,237,170	1,121,423
PROPERTY, PLANT AND EQUIPMENT	13,473,400	11,087,468
ACCUMULATED DEPRECIATION	(1,570,112)	(1,286,099)
	11,903,288	9,801,369
ADVANCES TO AND INVESTMENTS IN AFFILIATES	206,505	8,723
LONG-TERM PRICE RISK MANAGEMENT ASSETS	19,827	13,948
GOODWILL	1,220,006	781,233
INTANGIBLE ASSETS, net	335,767	264,690
OTHER NON-CURRENT ASSETS, net	155,485	158,606
Total assets	$15,078,048	$12,149,992

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, 2011	December 31, 2010
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$360,515	$301,997
Accounts payable to related companies	26,373	27,177
Exchanges payable	15,682	15,451
Price risk management liabilities	64,180	—
Accrued and other current liabilities	579,402	462,560
Current maturities of long-term debt	424,076	35,265
Total current liabilities	1,470,228	842,450
LONG-TERM DEBT, less current maturities	7,652,318	6,404,916
LONG-TERM PRICE RISK MANAGEMENT LIABILITIES	36,628	18,338
OTHER NON-CURRENT LIABILITIES	151,000	140,851
COMMITMENTS AND CONTINGENCIES (Note 13)		
EQUITY:		
General Partner	175,352	174,618
Limited Partners:		
Common Unitholders	4,965,032	4,542,656
Accumulated other comprehensive income	12,406	26,163
Total partners' capital	5,152,790	4,743,437
Noncontrolling interest	615,084	—
Total equity	5,767,874	4,743,437
Total liabilities and equity	$15,078,048	$12,149,992

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,		Nine Months Ended September 30,	
	2011	2010	2011	2010
REVENUES:				
Natural gas operations	$1,476,107	$1,082,866	$3,985,661	$3,435,521
Retail propane	213,496	183,786	962,258	914,372
Other	25,713	23,992	83,069	80,438
Total revenues	1,715,316	1,290,644	5,030,988	4,430,331
COSTS AND EXPENSES:				
Cost of products sold — natural gas operations	926,026	666,022	2,470,159	2,232,867
Cost of products sold — retail propane	141,868	104,533	587,460	519,796
Cost of products sold — other	7,632	6,856	20,992	20,470
Operating expenses	196,737	174,740	574,528	515,021
Depreciation and amortization	112,942	85,612	313,878	252,765
Selling, general and administrative	57,768	44,734	158,074	137,743
Total costs and expenses	1,442,973	1,082,497	4,125,091	3,678,662
OPERATING INCOME	272,343	208,147	905,897	751,669
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(124,000)	(101,241)	(347,706)	(309,217)
Equity in earnings of affiliates	6,713	595	13,386	10,848
Losses on non-hedged interest rate derivatives	(68,595)	(11,963)	(64,705)	(11,963)
Allowance for equity funds used during construction	636	12,432	705	18,039
Impairment of investments in affiliates	(5,355)	—	(5,355)	(52,620)
Other, net	(1,653)	1,410	(1,935)	(3,929)
INCOME BEFORE INCOME TAX EXPENSE	80,089	109,380	500,287	402,827
Income tax expense	4,039	1,993	20,419	12,486
NET INCOME	76,050	107,387	479,868	390,341
LESS: NET INCOME ATTRIBUTABLE TO NONCONTROLLING INTEREST	9,285	—	17,673	—
NET INCOME ATTRIBUTABLE TO PARTNERS	66,765	107,387	462,195	390,341
GENERAL PARTNER'S INTEREST IN NET INCOME	104,810	97,046	318,241	287,644
LIMITED PARTNERS' INTEREST IN NET INCOME (LOSS)	$(38,045)	$10,341	$143,954	$102,697
BASIC NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$(0.19)	$0.05	$0.68	$0.54
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	209,151,808	185,247,021	203,918,940	186,761,917
DILUTED NET INCOME (LOSS) PER LIMITED PARTNER UNIT	$(0.19)	$0.05	$0.68	$0.53
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	209,151,808	186,214,685	205,085,770	187,708,683

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,	
	2011	2010	2011	2010
Net income	$76,050	$107,387	$479,868	$390,341
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	(4,994)	(5,388)	(27,405)	(18,006)
Change in value of derivative instruments accounted for as cash flow hedges	6,126	34,776	14,583	59,410
Change in value of available-for-sale securities	(900)	(732)	(935)	(3,785)
	232	28,656	(13,757)	37,619
Comprehensive income	76,282	136,043	466,111	427,960
Less: Comprehensive income attributable to noncontrolling interest	9,285	—	17,673	—
Comprehensive income attributable to partners	$66,997	$136,043	$448,438	$427,960

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, 2011
(Dollars in thousands)
(unaudited)

	General Partner	Limited Partner Common Unitholders	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance, December 31, 2010	$174,618	$4,542,656	$ 26,163	$ —	$4,743,437
Distributions to partners	(317,356)	(546,155)	—	—	(863,511)
Distributions to noncontrolling interest	—	—	—	(18,900)	(18,900)
Units issued for cash	—	799,292	—	—	799,292
Capital contributions from noncontrolling interest	—	—	—	616,311	616,311
Units issued for acquisition of propane assets	—	3,000	—	—	3,000
Distributions on unvested unit awards	—	(5,687)	—	—	(5,687)
Non-cash unit-based compensation expense, net of units tendered by employees for tax withholdings	—	30,040	—	—	30,040
Non-cash executive compensation	19	919	—	—	938
Other comprehensive loss, net of tax	—	—	(13,757)	—	(13,757)
Other, net	(170)	(2,987)	—	—	(3,157)
Net income	318,241	143,954	—	17,673	479,868
Balance, September 30, 2011	$175,352	$4,965,032	$ 12,406	$ 615,084	$5,767,874

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, 2011	2010
CASH FLOWS PROVIDED BY OPERATING ACTIVITIES:		
Net income	$479,868	$390,341
Reconciliation of net income to net cash provided by operating activities:		
Impairment of investment in affiliate	5,355	52,620
Proceeds from termination of interest rate derivatives	—	26,495
Depreciation and amortization	313,878	252,765
Amortization of finance costs charged to interest	7,199	7,216
Non-cash unit-based compensation expense	30,201	21,422
Non-cash executive compensation expense	938	938
Distributions on unvested awards	(5,687)	(3,398)
Distributions in excess of equity in earnings of affiliates, net	2,177	20,765
Other non-cash	1,233	(10,922)
Changes in operating assets and liabilities, net of effects of acquisitions (see Note 4)	195,047	344,654
Net cash provided by operating activities	1,030,209	1,102,896
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash received	(1,971,438)	(156,388)
Capital expenditures (excluding allowance for equity funds used during construction)	(950,978)	(1,036,903)
Contributions in aid of construction costs	18,435	12,048
Advances to affiliates, net	(205,634)	(6,046)
Sale of investment in MEP	1,178	—
Proceeds from the sale of assets	5,338	13,742
Net cash used in investing activities	(3,103,099)	(1,173,547)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	5,283,107	809,949
Principal payments on debt	(3,644,454)	(1,007,617)
Net proceeds from issuance of Limited Partner units	799,292	1,086,991
Capital contribution from General Partner	—	8,932
Capital contributions from noncontrolling interest	616,311	—
Distributions to partners	(863,511)	(794,788)
Distributions to noncontrolling interest	(18,900)	—
Redemption of units	—	(23,299)
Debt issuance costs	(12,262)	—
Net cash provided by financing activities	2,159,583	80,168
INCREASE IN CASH AND CASH EQUIVALENTS	86,693	9,517
CASH AND CASH EQUIVALENTS, beginning of period	49,540	68,183
CASH AND CASH EQUIVALENTS, end of period	$136,233	$77,700

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, Energy Transfer Partners GP, L.P. (our “General Partner” or “ETP GP”), which is in turn managed by its general partner, Energy Transfer Partners, L.L.C. (“ETP LLC”). Energy Transfer Equity, L.P. (“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

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

- La Grange Acquisition, L.P., which conducts business under the assumed name of Energy Transfer Company (“ETC OLP”), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations. ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and NGLs in the states of Texas, Louisiana, New Mexico, Utah, West Virginia and Colorado. 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, North Texas System and Northern Louisiana assets. We also own and operate natural gas gathering pipelines and conditioning facilities in the Piceance and Uinta Basins of Colorado and Utah, respectively. ETC OLP also owns a 70% interest in Lone Star NGL LLC (“Lone Star”), which is described in Note 3.
- Energy Transfer Interstate Holdings, LLC (“ET Interstate”), a Delaware limited liability company with revenues consisting primarily of fees earned from natural gas transportation services and operational gas sales. ET Interstate is the parent company of:
- Transwestern Pipeline Company, LLC (“Transwestern”), a Delaware limited liability company engaged in interstate transportation of natural gas. Transwestern’s revenues consist primarily of fees earned from natural gas transportation services and operational gas sales.
- ETC Fayetteville Express Pipeline, LLC (“ETC FEP”), a Delaware limited liability company engaged in interstate transportation of natural gas.
- ETC Tiger Pipeline, LLC (“ETC Tiger”), a Delaware limited liability company engaged in interstate transportation of natural gas.
- ETC Compression, LLC (“ETC Compression”), a Delaware limited liability company engaged in natural gas compression services and related equipment sales.
- Heritage Operating, L.P. (“HOLP”), a Delaware limited partnership primarily engaged in retail propane operations. Our retail propane operations focus on sales of propane and propane-related products and services. The retail propane customer base includes residential, commercial, industrial and agricultural customers.
- Titan Energy Partners, L.P. (“Titan”), a Delaware limited partnership also engaged in retail propane operations.

Our historical financial statements reflect the following reportable business segments: intrastate natural gas transportation and storage; interstate natural gas transportation; midstream; and retail propane and other retail propane related operations. In addition, our consolidated financial statements now reflect a new NGL transportation and services segment, which primarily consists of Lone Star's operations.

Preparation of Interim Financial Statements

The accompanying consolidated balance sheet as of December 31, 2010, which has been derived from audited financial statements, and the unaudited interim consolidated financial statements and notes thereto of Energy Transfer Partners as of September 30, 2011 and for the three and nine month periods ended September 30, 2011 and 2010, have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”) for interim consolidated financial information and pursuant to the rules and regulations of the SEC. Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership's operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting. Management has evaluated subsequent events through the date the financial statements were issued.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners as of September 30, 2011, and the Partnership's results of operations and cash flows for the three and nine months ended September 30, 2011 and 2010. 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, 2010, as filed with the SEC on February 28, 2011.

Certain prior period amounts have been reclassified to conform to the 2011 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 results could differ from those estimates.

3. ACQUISITIONS AND DIVESTITURES:

LDH Acquisition

On May 2, 2011, ETP-Regency Midstream Holdings, LLC ("ETP-Regency LLC"), a joint venture owned 70% by the Partnership and 30% by Regency Energy Partners LP ("Regency"), acquired all of the membership interest in LDH Energy Asset Holdings LLC ("LDH"), from Louis Dreyfus Highbridge Energy LLC ("Louis Dreyfus") for approximately $1.98 billion in cash (the "LDH Acquisition"), including working capital adjustments. The Partnership contributed approximately $1.38 billion to ETP-Regency LLC to fund its 70% share of the purchase price. Subsequent to closing, ETP-Regency LLC was renamed Lone Star.

Lone Star owns and operates a natural gas liquids storage, fractionation and transportation business. Lone Star's storage assets are primarily located in Mont Belvieu, Texas, and its West Texas Pipeline transports NGLs through an intrastate pipeline system that originates in the Permian Basin in west Texas, passes through the Barnett Shale production area in north Texas and terminates at the Mont Belvieu storage and fractionation complex. Lone Star also owns and operates fractionation and processing assets located in Louisiana. The acquisition of LDH by Lone Star significantly expands the Partnership's asset portfolio by adding an NGL platform with storage, transportation and fractionation capabilities. Additionally, this acquisition is expected to provide additional consistent fee-based revenues.

We accounted for the LDH Acquisition using the acquisition method of accounting. Lone Star’s results of operations are included in our NGL transportation and services segment. We previously reported Lone Star’s 20% interest in a processing plant as part of our midstream segment in our interim financial statements as of and for the period ended June 30, 2011; however, it is now reflected in our NGL transportation and services segment as well for all post-acquisition periods, in order to conform our segment presentation to the same level of data that our executive management and chief operating decision maker has chosen to review. Regency’s 30% interest in Lone Star is reflected as noncontrolling interest.

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The following table summarizes the assets acquired and liabilities assumed recognized as of the acquisition date:

Total current assets	$118,177
Property, plant and equipment[(1)]	1,419,591
Goodwill	432,026
Intangible assets	81,000
Other assets	157
	2,050,951
Total current liabilities	74,964
Other long-term liabilities	438
	75,402
Total consideration	1,975,549
Cash received	31,231
Total consideration, net of cash received	$1,944,318

(1) Property, plant and equipment (and estimated useful lives) consists of the following:

Land and improvements	$30,759
Buildings and improvements (10 to 40 years)	3,123
Pipelines and equipment (20 to 65 years)	662,881
Natural gas liquids storage (40 years)	682,419
Linepack	704
Vehicles (3 to 20 years)	242
Furniture and fixtures (3 to 10 years)	49
Other (5 to 10 years)	8,526
Construction work-in-process	30,888
Property, plant and equipment	$1,419,591

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the three and nine months ended September 30, 2011 and 2010 are presented as if the LDH Acquisition had been completed on January 1, 2010.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues	$1,715,316	$1,359,787	$5,139,577	$4,663,167
Net income	76,050	108,399	480,031	393,738
Net income attributable to partners	66,765	102,914	455,401	377,176
Basic net income (loss) per Limited Partner unit	$(0.19)	$0.03	$0.65	$0.47
Diluted net income (loss) per Limited Partner unit	$(0.19)	$0.03	$0.64	$0.46

The pro forma consolidated results of operations include adjustments to:

- include the results of Lone Star for all periods presented;
- include the incremental expenses associated with the fair value adjustments recorded as a result of applying the acquisition method of accounting;
- include incremental interest expense related to the financing of ETP's proportionate share of the purchase price; and
- reflect noncontrolling interest related to Regency's 30% interest in Lone Star.

The pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the combined operations.

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Pending Acquisition

On July 19, 2011, ETE entered into a Second Amended and Restated Agreement and Plan of Merger (the "Second Amended SUG Merger Agreement") with Sigma Acquisition Corporation, a Delaware corporation and wholly-owned subsidiary of ETE ("Merger Sub"), and Southern Union Company, a Delaware corporation ("SUG"). The Second Amended SUG Merger Agreement modifies certain terms of the Amended and Restated Agreement and Plan of Merger entered into by ETE, Merger Sub and SUG on July 4, 2011 (the "First Amended Merger Agreement"). Under the terms of the Second Amended SUG Merger Agreement, Merger Sub will merge with and into SUG, with SUG continuing as the surviving entity and becoming a wholly-owned subsidiary of ETE (the "SUG Merger"), subject to certain conditions to closing.

Consummation of the SUG Merger is subject to customary conditions, including, without limitation: (i) the adoption of the Second Amended SUG Merger Agreement by the stockholders of SUG, (ii) the receipt of required approvals from the Federal Energy Regulatory Commission (the "FERC"), the Missouri Public Service Commission and, if required, the Massachusetts Department of Public Utilities, (iii) the effectiveness of a registration statement on Form S-4 relating to the ETE Common Units to be issued in the SUG Merger, and (iv) the absence of any law, injunction, judgment or ruling prohibiting or restraining the SUG Merger or making the consummation of the SUG Merger illegal. On July 28, 2011, the waiting period applicable to the SUG Merger under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended (the "HSR Act") expired. On September 23, 2011, the FERC issued a letter order authorizing the transfer of FERC-jurisdictional facilities resulting from the SUG Merger. On October 27, 2011, the registration statement on Form S-4 was declared effective by the SEC.

On July 19, 2011, ETP entered into an Amended and Restated Agreement and Plan of Merger with ETE (the "Amended Citrus Merger Agreement"). The Amended Citrus Merger Agreement modifies certain terms of the Agreement and Plan of Merger entered into by ETP and ETE on July 4, 2011. Pursuant to the terms of the Second Amended SUG Merger Agreement, immediately prior to the effective time of the SUG Merger, ETE will assign and SUG will assume the benefits and obligations of ETE under the Amended Citrus Merger Agreement.

Under the Amended Citrus Merger Agreement, it is anticipated that SUG will cause the contribution to ETP of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission pipeline system and is currently jointly owned by SUG and El Paso Corporation (the "Citrus Transaction"). The Citrus Transaction will be effected through the merger of Citrus ETP Acquisition, L.L.C., a Delaware limited liability company and wholly-owned subsidiary of ETP, with and into CrossCountry Energy, LLC, a Delaware limited liability company and wholly-owned subsidiary of SUG that indirectly owns a 50% interest in Citrus Corp. ("CrossCountry"). In exchange for the interest in Citrus Corp., SUG will receive approximately $2.00 billion, consisting of approximately $1.9 billion in cash and $105 million of ETP common units, with the value of the ETP common units based on the volume-weighted average trading price for the ten consecutive trading days ending immediately prior to the date that is three trading days prior to the closing date of the Citrus Transaction. In order to increase the expected accretion to be derived from the Citrus Transaction, ETE has agreed to relinquish its rights to approximately $220 million of the incentive distributions from ETP that ETE would otherwise be entitled to receive over 16 consecutive quarters following the closing of the transaction.

The Amended Citrus Merger Agreement includes customary representations, warranties and covenants of ETP and ETE (including representations, warranties and covenants relating to SUG, CrossCountry and certain of CrossCountry's affiliates). Consummation of the Citrus Transaction is subject to customary conditions, including, without limitation: (i) satisfaction or waiver of the closing conditions set forth in the Second Amended SUG Merger Agreement, (ii) the receipt by ETP of any necessary waivers or amendments to its credit agreement, (iii) the amendment of ETP's partnership agreement to reflect the agreed upon relinquishment by ETE of incentive distributions from ETP discussed above, and (iv) the absence of any order, decree, injunction or law prohibiting or making the consummation of the transactions contemplated by the Amended Citrus Merger Agreement illegal. The Amended Citrus Merger Agreement contains certain termination rights for both ETE and ETP, including among others, the right to terminate if the Citrus Transaction is not completed by December 31, 2012 or if the Second Amended SUG Merger Agreement is terminated.

Pursuant to the Amended Citrus Merger Agreement, ETE has granted ETP a right of first offer with respect to any disposition by ETE or SUG of Southern Union Gas Services, a subsidiary of SUG that owns and operates a natural gas gathering and processing system serving the Permian Basin in West Texas and New Mexico.

Propane Operations

In October 2011, we entered into an agreement with AmeriGas Partners, L.P. ("AmeriGas") to contribute our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") to AmeriGas in exchange for consideration of approximately $2.9 billion. The consideration consists of $1.5 billion in cash and common units of AmeriGas valued at $1.32 billion at the time of the execution of the agreement, plus the assumption of certain liabilities of the Propane Business. One of our closing deliverables under the agreement is that we enter into and deliver a support agreement with AmeriGas that

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we will provide contingent, residual support of senior notes issued by AmeriGas to finance the cash portion of the purchase price. The transaction is subject to customary closing conditions, including approval under the HSR Act, and is expected to close late 2011 or early 2012.

We have not reflected our Propane operations as discontinued operations as we expect to have a continuing involvement in this business as a result of the investment in AmeriGas that would be transferred as consideration for the transaction.

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) included in cash flows from operating activities is comprised as follows:

	Nine Months Ended September 30,	
	2011	2010
Accounts receivable	$28,318	$166,064
Accounts receivable from related companies	(22,917)	11,596
Inventories	67,716	113,568
Exchanges receivable	6,300	4,663
Other current assets	(25,956)	26,796
Other non-current assets, net	7,061	4,560
Accounts payable	(11,333)	(86,291)
Accounts payable to related companies	(804)	(7,253)
Exchanges payable	231	(8,003)
Accrued and other current liabilities	78,997	58,925
Other non-current liabilities	1,298	(600)
Price risk management assets and liabilities, net	66,136	60,629
Net change in operating assets and liabilities, net of effects of acquisitions	$195,047	$344,654

Non-cash investing and financing activities are as follows:

	Nine Months Ended September 30,	
	2011	2010
NON-CASH INVESTING ACTIVITIES:		
Accrued capital expenditures	$128,874	$55,013
Transfer of MEP joint venture interest in exchange for redemption of Common Units	$—	$588,741
NON-CASH FINANCING ACTIVITIES:		
Issuance of common units in connection with acquisition of propane assets	$3,000	$—
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$4,166	$618

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5. INVENTORIES:

Inventories consisted of the following:

	September 30, 2011	December 31, 2010
Natural gas and NGLs, excluding propane	$118,989	$168,378
Propane	75,085	76,341
Appliances, parts and fittings and other	112,821	117,339
Total inventories	$306,895	$362,058

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. GOODWILL AND INTANGIBLE ASSETS:

A net increase in goodwill of $438.8 million was recorded during the nine months ended September 30, 2011 primarily due to the LDH acquisition referenced in Note 3. This additional goodwill is expected to be deductible for tax purposes. In addition, we recorded customer contracts of $81 million with useful lives ranging from 3 to 15 years. Components and useful lives of intangible assets were as follows:

	September 30, 2011		December 31, 2010	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Customer relationships, contracts and agreements (3 to 46 years)	$336,709	$(89,086)	$251,418	$(74,910)
Noncompete agreements (3 to 15 years)	15,893	(7,900)	21,165	(11,888)
Patents (9 years)	750	(181)	750	(118)
Other (10 to 15 years)	1,320	(566)	1,320	(492)
Total amortizable intangible assets	354,672	(97,733)	274,653	(87,408)
Non-amortizable intangible assets —				
Trademarks	78,828	—	77,445	—
Total intangible assets	$433,500	$(97,733)	$352,098	$(87,408)

Aggregate amortization expense of intangible assets was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Reported in depreciation and amortization	$7,267	$4,986	$17,683	$14,986

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

Years Ending December 31:	
2012	$24,716
2013	20,379
2014	19,258
2015	18,371
2016	17,591

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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, midstream and retail propane operations. We have not completed our annual impairment tests for 2011 and have not recorded any impairments related to amortizable intangible assets during the nine months ended September 30, 2011.

Recently Issued Accounting Standards

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment ("ASU 2011-08"), which simplifies how entities test goodwill for impairment. ASU 2011-08 gives entities the option, under certain circumstances, to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. ASU 2011-08 is effective for fiscal years beginning after December 15, 2011, and early adoption is permitted. We are currently evaluating early adoption of ASU 2011-08, but we do not expect adoption of this standard will materially impact our financial position or results of operations.

7. FAIR VALUE MEASUREMENTS:

The carrying amounts of cash and cash equivalents, accounts receivable and accounts payable approximate their fair value. Price risk management assets and liabilities are recorded at fair value.

Based on the estimated borrowing rates currently available to us and our subsidiaries for loans with similar terms and average maturities, the aggregate fair value and carrying amount of our consolidated debt obligations at September 30, 2011 was $8.58 billion and $8.08 billion, respectively. As of December 31, 2010, the aggregate fair value and carrying amount of our consolidated debt obligations was $7.21 billion and $6.44 billion, respectively.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our consolidated balance sheets. We determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible "level" of inputs. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter ("OTC") commodity derivatives entered into directly with third parties as a Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. Additionally, we consider our options transacted through our clearing broker as having Level 2 inputs due to the level of activity of these contracts on the exchange in which they trade. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of credit risk. Level 3 inputs are unobservable. We currently do not have any recurring fair value measurements that are considered Level 3 valuations. During the period ended September 30, 2011, no transfers were made between any levels within the fair value hierarchy.

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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, 2011 and December 31, 2010 based on inputs used to derive their fair values:

	Fair Value Total	Fair Value Measurements at September 30, 2011 Using	
		Level 1	Level 2
Assets:			
Marketable securities	$3,151	$3,151	$—
Interest rate derivatives	30,564	—	30,564
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	74,892	74,892	—
Swing Swaps IFERC	21,818	1,074	20,744
Fixed Swaps/Futures	70,270	70,112	158
Options — Puts	13,348	—	13,348
Forward Physical Swaps	738	—	738
Propane — Forwards/Swaps	77	—	77
Total commodity derivatives	181,143	146,078	35,065
Total Assets	$214,858	$149,229	$65,629
Liabilities:			
Interest rate derivatives	$(98,580)	$—	$(98,580)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(68,918)	(68,918)	—
Swing Swaps IFERC	(22,707)	(1,988)	(20,719)
Fixed Swaps/Futures	(48,287)	(48,133)	(154)
Options — Puts	(423)	—	(423)
Options — Calls	(122)	—	(122)
Forward Physical Swaps	(482)	—	(482)
Propane — Forwards/Swaps	(2,086)	—	(2,086)
Total commodity derivatives	(143,025)	(119,039)	(23,986)
Total Liabilities	$(241,605)	$(119,039)	$(122,566)

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	Fair Value Total	Fair Value Measurements at December 31, 2010 Using	
		Level 1	Level 2
Assets:			
Marketable securities	$2,032	$2,032	$—
Interest rate derivatives	20,790	—	20,790
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	15,756	15,756	—
Swing Swaps IFERC	1,682	1,562	120
Fixed Swaps/Futures	42,474	42,474	—
Options — Puts	26,241	—	26,241
Options — Calls	75	—	75
Propane – Forwards/Swaps	6,864	—	6,864
Total commodity derivatives	93,092	59,792	33,300
Total Assets	$115,914	$61,824	$54,090
Liabilities:			
Interest rate derivatives	$(18,338)	$—	$(18,338)
Commodity derivatives:			
Natural Gas:			
Basis Swaps IFERC/NYMEX	(17,372)	(17,372)	—
Swing Swaps IFERC	(3,768)	(3,520)	(248)
Fixed Swaps/Futures	(41,825)	(41,825)	—
Options — Puts	(7)	—	(7)
Options — Calls	(2,643)	—	(2,643)
Total commodity derivatives	(65,615)	(62,717)	(2,898)
Total Liabilities	$(83,953)	$(62,717)	$(21,236)

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

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income attributable to partners	$66,765	$107,387	$462,195	$390,341
General Partner's interest in net income	104,810	97,046	318,241	287,644
Limited Partners' interest in net (loss) income	(38,045)	10,341	143,954	102,697
Additional earnings allocated from General Partner	9	161	572	790
Distributions on employee unit awards, net of allocation to General Partner	(1,894)	(1,142)	(5,619)	(3,451)
Net (loss) income available to Limited Partners	$(39,930)	$9,360	$138,907	$100,036
Weighted average Limited Partner units — basic	209,151,808	185,247,021	203,918,940	186,761,917
Basic net (loss) income per Limited Partner unit	$(0.19)	$0.05	$0.68	$0.54
Weighted average Limited Partner units	209,151,808	185,247,021	203,918,940	186,761,917
Dilutive effect of unvested Unit Awards	—	967,664	1,166,830	946,766
Weighted average Limited Partner units, assuming dilutive effect of unvested Unit Awards	209,151,808	186,214,685	205,085,770	187,708,683
Diluted net (loss) income per Limited Partner unit	$(0.19)	$0.05	$0.68	$0.53

Based on the declared distribution rate of $0.89375 per Common Unit, distributions to be paid for the three months ended September 30, 2011 are expected to be $295.9 million in total, which exceeds net income for the period by $229.2 million. Accordingly, the distributions expected to be paid to the General Partner, including incentive distributions, further exceeded the net income for the three months ended September 30, 2011, and as a result, a net loss was allocated to the Limited Partners for the period.

9. DEBT OBLIGATIONS:

Senior Notes

In May 2011, we completed a public offering of $800 million aggregate principal amount of 4.65% Senior Notes due June 1, 2021 and $700 million aggregate principal amount of 6.05% Senior Notes due June 1, 2041. We used the net proceeds of $1.48 billion to repay all of the borrowings outstanding under our revolving credit facility, to fund capital expenditures related to pipeline construction projects 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.

Revolving Credit Facility

The indebtedness under ETP's revolving 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.

As of September 30, 2011, we had $574.6 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.40 billion taking into account letters of credit of $24.3 million. The weighted average interest rate on the total amount outstanding as of September 30, 2011 was 0.80%.

On October 27, 2011, we amended and restated the ETP Credit Facility to, among other things, (i) allow for borrowings of up to $2.5 billion; (ii) extend the maturity date from July 20, 2012 to October 27, 2016 (which may be extended by one year with lender approval); (iii) allow for an increase in the size of the credit facility to $3.75 billion (subject to obtaining lender commitments for the additional borrowing capacity); and (iv) to adjust the interest rates and commitment fees to current market terms. Following this amendment and based on our current ratings, the interest margin for LIBOR rate loans is 1.50% and the commitment fee for unused borrowing capacity is 0.25%.

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, 2011.

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10. EQUITY:

Common Units Issued

The change in Common Units during the nine months ended September 30, 2011 was as follows:

	Number of Units
Outstanding at December 31, 2010	193,212,590
Common Units issued in connection with public offerings	14,202,500
Common Units issued in connection with the Equity Distribution Agreement	1,895,715
Common Units issued in connection with the Distribution Reinvestment Plan	175,863
Common Units issued in connection with propane asset purchase	66,499
Common Units issued under equity incentive plans	25,388
Outstanding at September 30, 2011	209,578,555

In April 2011, we issued 14,202,500 Common Units through a public offering. The proceeds of $695.5 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 currently have an Equity Distribution Agreement with Credit Suisse Securities (USA) LLC ("Credit Suisse") under which we may offer and sell from time to time through Credit Suisse, as our sales agent, Common Units having an aggregate offering price of up to $200 million. During the nine months ended September 30, 2011, we received proceeds from units issued pursuant to this agreement of approximately $96.3 million, net of commissions, which proceeds were used for general partnership purposes. Approximately $77.5 million of our Common Units remain available to be issued under the agreement based on trades initiated through September 30, 2011.

In April 2011, we filed a registration statement with the SEC covering our Distribution Reinvestment Plan (the "DRIP"). The DRIP 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 covers the issuance of up to 5,750,000 Common Units under the DRIP.

For the nine months ended September 30, 2011, distributions of approximately $7.6 million were reinvested under the DRIP resulting in the issuance of 175,863 Common Units.

Quarterly Distributions of Available Cash

Following are distributions declared and/or paid by us subsequent to December 31, 2010:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2010	February 7, 2011	February 14, 2011	$0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	0.89375

Accumulated Other Comprehensive Income

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

	September 30, 2011	December 31, 2010
Net gains on commodity related hedges	$12,423	$25,245
Unrealized (losses) gains on available-for-sale securities	(17)	918
Total AOCI, net of tax	$12,406	$26,163

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11. UNIT-BASED COMPENSATION PLANS:

During the nine months ended September 30, 2011, employees were granted a total of 556,700 unvested awards with five-year service vesting requirements, and directors were granted a total of 2,580 unvested awards with three-year service vesting requirements. The weighted average grant-date fair value of these awards was $53.12 per unit. As of September 30, 2011 a total of 2,349,540 unit awards remain unvested, including the new awards granted during the period. We expect to recognize a total of $58.3 million in compensation expense over a weighted average period of 1.7 years related to unvested awards.

12. 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,	
	2011	2010	2011	2010
Current expense (benefit):				
Federal	$1,125	$(3,794)	$6,788	$(877)
State	2,510	1,450	11,635	8,871
Total	3,635	(2,344)	18,423	7,994
Deferred expense (benefit):				
Federal	872	4,357	1,876	4,778
State	(468)	(20)	120	(286)
Total	404	4,337	1,996	4,492
Total income tax expense	$4,039	$1,993	$20,419	$12,486

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

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

Regulatory Matter

On September 29, 2006, Transwestern filed revised tariff sheets under Section 4(e) of the Natural Gas Act (“NGA”) proposing a general rate increase to be effective on November 1, 2006. In April 2007, the FERC approved a Stipulation and Agreement of Settlement that resolved the primary components of the rate case. Under the terms of the settlement, Transwestern was required to file a new general NGA Section 4 rate case no later than October 1, 2011. However, Transwestern sought and on September 2, 2011 was granted an extension of the filing date until December 1, 2011 to allow time for settlement discussions with shippers. On September 21, 2011, Transwestern filed a proposed settlement with the FERC, which was approved by the FERC on October 31, 2011. The settlement maintains the currently effective transportation and fuel tariff rates with the exception that it reduces certain San Juan Lateral fuel rates staggered over the three year period beginning in April 2012. The settlement also resolves certain non-rate matters and reflects a continuation of the accounting practices from the prior rate settlement. Under the settlement, Transwestern will be required to file a Section 4 rate case on October 1, 2014.

Guarantee - Fayetteville Express Pipeline LLC

Fayetteville Express Pipeline LLC (“FEP”), a joint venture entity in which we own a 50% interest, had a credit agreement that provided for a $1.1 billion senior revolving credit facility (the “FEP Facility”). We guaranteed 50% of the obligations of FEP under the FEP Facility, with the remainder of FEP Facility obligations guaranteed by Kinder Morgan Energy Partners, L.P. (“KMP”). Amounts borrowed under the FEP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate.

In July 2011, the FEP Facility was repaid with capital contributions from ETP and KMP totaling $390 million along with proceeds from a $600 million term loan credit facility maturing in July 2012 (which can be extended for one year at the option of FEP). Upon closing and funding of the term loan facility, the FEP Facility was terminated. FEP also entered into a $50 million revolving credit facility maturing in July 2015. FEP's indebtedness under its new credit facilities is not guaranteed by ETP or KMP.

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NGL Pipeline Regulation

We have interests in NGL pipelines located in Texas. We believe that these pipelines do not provide interstate service and that they are thus not subject to the jurisdiction of the FERC under the Interstate Commerce Act ("ICA") and the Energy Policy Act of 1992. Under the ICA, tariffs must be just and reasonable and not unduly discriminatory or confer any undue preference. We cannot guarantee that the jurisdictional status of our NGL facilities will remain unchanged; however, should they be found jurisdictional, the FERC's rate-making methodologies may limit our ability to set rates based on our actual costs, may delay or limit the use of rates that reflect increased costs and may subject us to potentially burdensome and expensive operational, reporting and other requirements. Any of the foregoing could adversely affect our business, revenues and cash flow.

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 have also entered into several propane purchase and supply commitments, which are typically one year agreements with varying terms as to quantities, prices and expiration dates. We believe that the terms of these agreements are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

We have certain non-cancelable leases for property and equipment, which require fixed monthly rental payments and expire at various dates through 2034. Rental expense under these operating leases has been included in operating expenses in the accompanying statements of operations and totaled approximately $5.5 million and $5.0 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011 and 2011, rental expense for operating leases totaled approximately $15.7 million and $16.3 million, respectively.

Our propane operations have an agreement with Enterprise Products Partners L.P. (together with its subsidiaries "Enterprise") (see Note 15) to supply a portion of our propane requirements. The agreement will continue until March 2015 and includes an option to extend the agreement for an additional year.

In connection with the sale of our investment in M-P Energy in October 2007, we executed a propane purchase agreement for approximately 90 million gallons per year through 2015 at market prices plus a nominal fee.

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.

Litigation and Contingencies

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

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 September 30, 2011 and December 31, 2010, accruals of approximately $13.3 million and $10.2 million, respectively, were reflected on our balance sheets related to these contingent obligations. 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, 2011 or December 31, 2010 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, 2011 and December 31, 2010, accruals on an undiscounted basis of $12.6 million and $13.8 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 polychlorinated biphenyls (“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 2025 is $7.9 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 U.S. Environmental Protection Agency’s (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.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, and we believe that our operations have not contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our September 30, 2011 or December 31, 2010 consolidated balance sheets. Based on information currently available to us, the presence of contamination and remediation activities at these sites are not expected to have a material adverse effect on our financial condition or results of operations.

On August 20, 2010, the EPA published new regulations under the federal Clean Air Act ("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 we replace equipment or expand existing facilities 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.

Our pipeline operations are subject to regulation by the U.S. Department of Transportation ("DOT") under the Pipeline Hazardous Materials Safety Administration ("PHMSA"), pursuant to which the PHMSA has established requirements relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as "high consequence areas." Activities under these integrity management programs involve the performance of internal pipeline inspections, pressure testing or other effective means to assess the integrity of these regulated pipeline segments, and the regulations require prompt action to address integrity issues raised by the assessment and analysis. For the three months ended September 30, 2011 and 2010, $4.2 million and $5.8 million, respectively, of capital costs and $3.9 million of operating and maintenance costs have been incurred for pipeline integrity testing. For the nine months ended September 30, 2011 and 2010, $9.7 million and $10.8 million, respectively, of capital costs and $9.8 million and $10.2 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 ETP to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines; 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 federal Occupational Safety and Health Act ("OSHA") and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazardous communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the OSHA requirements, including general industry standards, record keeping requirements, and monitoring of occupational exposure to regulated substances.

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

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14. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To manage the impact of volatility from these prices, we utilize various exchange-traded and OTC commodity financial instrument contracts. These contracts consist primarily of futures, swaps and options and are recorded at fair value in the consolidated balance sheets.

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.

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 ourselves from the volatility in the energy commodities markets; however, net unbalanced positions can exist.

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

Our propane segment permits customers to guarantee the propane delivery price for the next heating season. As we execute fixed sales price contracts with our customers, we may enter into propane futures contracts to fix the purchase price related to these sales contracts, thereby locking in a gross profit margin. Additionally, we may use propane futures contracts to secure the purchase price of our propane inventory for a percentage of our anticipated propane sales.

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The following table details our outstanding commodity-related derivatives:

	September 30, 2011		December 31, 2010	
	Notional Volume	Maturity	Notional Volume	Maturity
Mark-to-Market Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(39,952,500)	2011-2013	(38,897,500)	2011
Swing Swaps IFERC (MMBtu)	30,517,500	2011-2013	(19,720,000)	2011
Fixed Swaps/Futures (MMBtu)	(15,517,500)	2011-2012	(2,570,000)	2011
Forward Physical Contracts (MMBtu)	12,324,054	2011-2012	—	—
Options — Calls (MMBtu)	—	—	(3,000,000)	2011
Propane:				
Forwards/Swaps (Gallons)	52,668,000	2011-2012	1,974,000	2011
Fair Value Hedging Derivatives				
Natural Gas:				
Basis Swaps IFERC/NYMEX (MMBtu)	(19,685,000)	2011-2012	(28,050,000)	2011
Fixed Swaps/Futures (MMBtu)	(29,837,500)	2011-2012	(39,105,000)	2011
Hedged Item — Inventory (MMBtu)	29,837,500	2011	39,105,000	2011
Cash Flow Hedging Derivatives				
Natural Gas:				
Fixed Swaps/Futures (MMBtu)	460,000	2011	(210,000)	2011
Options — Puts (MMBtu)	9,390,000	2011-2012	26,760,000	2011-2012
Options — Calls (MMBtu)	(9,390,000)	2011-2012	(26,760,000)	2011-2012
Propane:				
Forwards/Swaps (Gallons)	—	—	32,466,000	2011

We expect gains of $11.6 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. In order to maintain a cost effective capital structure, we borrow funds using a mix of fixed rate debt and variable rate debt. We manage our current 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.

We had the following interest rate swaps outstanding as of September 30, 2011 and December 31, 2010, none of which were designated as hedges for accounting purposes:

Term	Type [(1)]	Notional Amount Outstanding September 30, 2011	Notional Amount Outstanding December 31, 2010
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	400,000
July 2013[(2)]	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	300,000	—
July 2018	Pay a floating rate plus a spread of 4.01% and receive a fixed rate of 6.70%	500,000	500,000

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(1) As of September 30, 2011. Floating rates are based on 3-month LIBOR.
(2) 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 counterparty.

Our counterparties consist primarily of petrochemical companies and other industrials, mid-size to major oil and gas companies and power 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 performance.

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 $56.4 million and $52.2 million as of September 30, 2011 and December 31, 2010, 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 sheets and recognized in net income or other comprehensive income.

Derivative Summary

The following table provides a balance sheet overview of the Partnership's derivative assets and liabilities as of September 30, 2011 and December 31, 2010:

	Fair Value of Derivative Instruments			
	Asset Derivatives		Liability Derivatives	
	September 30, 2011	December 31, 2010	September 30, 2011	December 31, 2010
Derivatives designated as hedging instruments:				
Commodity derivatives (margin deposits)	$43,337	$35,031	$(461)	$(6,631)
Commodity derivatives	158	6,589	(154)	—
	43,495	41,620	(615)	(6,631)
Derivatives not designated as hedging instruments:				
Commodity derivatives (margin deposits)	146,589	64,940	(149,598)	(72,729)
Commodity derivatives	815	275	(2,568)	—
Interest rate derivatives	30,564	20,790	(98,580)	(18,338)
	177,968	86,005	(250,746)	(91,067)
Total derivatives	$221,463	$127,625	$(251,361)	$(97,698)

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."

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.

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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,	
	2011	2010	2011	2010
Derivatives in cash flow hedging relationships:				
Commodity derivatives	$6,127	$36,035	$14,470	$60,992
Interest rate derivatives	—	(1,162)	—	(1,367)
Total	$6,127	$34,873	$14,470	$59,625

	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,	
		2011	2010	2011	2010
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$5,116	$6,780	$27,069	$19,153
Interest rate derivatives	Interest expense	—	(1,635)	—	(1,493)
Total		$5,116	$5,145	$27,069	$17,660

	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,	
		2011	2010	2011	2010
Derivatives in cash flow hedging relationships:					
Commodity derivatives	Cost of products sold	$(112)	$241	$351	$346
Total		$(112)	$241	$351	$346

	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,	
		2011	2010	2011	2010
Derivatives in fair value hedging relationships (including hedged item):					
Commodity derivatives	Cost of products sold	$(3,559)	$9,968	$18,732	$9,001
Total		$(3,559)	$9,968	$18,732	$9,001

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	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,	
		2011	2010	2011	2010
Derivatives not designated as hedging instruments:					
Commodity derivatives	Cost of products sold	$9,175	$9,438	$4,174	$10,110
Interest rate derivatives	Losses on non-hedged interest rate derivatives	(68,595)	(11,963)	(64,705)	(11,963)
Total		$(59,420)	$(2,525)	$(60,531)	$(1,853)

We recognized $0.7 million and $12.5 million of unrealized gains on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the three months ended September 30, 2011 and 2010, respectively. We recognized $2.8 million of unrealized gains and $32.8 million of unrealized losses on commodity derivatives not in fair value hedging relationships (including the ineffective portion of commodity derivatives in cash flow hedging relationships) for the nine months ended September 30, 2011 and 2010, respectively. For the three months ended September 30, 2011 and 2010 we recognized unrealized losses of $7.1 million and unrealized gains of $8.2 million, respectively, on commodity derivatives and related hedged inventory accounted for as fair value hedges. For the nine months ended September 30, 2011 and 2010 we recognized unrealized losses of $1.3 million and of $35.3 million, respectively, on commodity derivatives and related hedged inventory accounted for as fair value hedges.

15. RELATED PARTY TRANSACTIONS:

Regency became a related party on May 26, 2010 in connection with ETE's acquisition of Regency's general partner. We provide Regency with certain natural gas sales and transportation services and compression equipment, and Regency provides us with certain contract compression services. For the nine months ended September 30, 2011, we recorded revenue of $25.9 million, cost of products sold of $26.4 million and operating expenses of $2.3 million related to transactions with Regency. For the period from May 26, 2010 to September 30, 2010, we recorded revenues of $0.9 million, costs of products sold of $1.4 million and operating expenses of $0.4 million related to transactions with Regency. For the three months ended September 30, 2011, we recorded revenue of $6.9 million, cost of products sold of $7.2 million and operating expenses of $0.4 million related to transactions with Regency. For the three months ended September 30, 2010, we recorded revenues of $0.9 million, costs of products sold of $0.7 million and operating expenses of $0.2 million related to transactions with Regency.

On September 1, 2011, Regency exercised its option to acquire our remaining 0.1% interest in MEP for approximately $1.2 million in cash.

We received $12.7 million and $3.7 million in management fees from ETE for the provision of various general and administrative services for ETE's benefit for the nine months ended September 30, 2011 and 2010, respectively. For the three months ended September 30, 2011 and 2010 we received $4.4 million and $2.6 million, respectively in management fees from ETE for the provision of various general and administrative services for ETE's benefit. The management fees for the three and nine months ended September 30, 2011 reflect the provision of various general and administrative services for Regency. For the three and nine months ended September 30, 2011 we recorded from Regency $1.7 million and $4.9 million, respectively, for reimbursement of various general and administrative expenses incurred by us.

Enterprise is considered to be a related party to us due to Enterprise's holdings of outstanding common units of ETE. We and Enterprise transport natural gas on each other's pipelines, share operating expenses on jointly-owned pipelines and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise.

Our propane operations purchase a portion of our propane requirements from Enterprise pursuant to an agreement that expires in 2015 and includes an option to extend the agreement for an additional year. The following table presents sales to and purchases from Enterprise:

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	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Natural Gas Operations:				
Sales	$164,339	$126,992	$462,359	$402,238
Purchases	3,938	396	21,898	13,928
Propane Operations:				
Sales	395	262	10,613	11,228
Purchases	86,673	58,642	328,830	276,821

As of September 30, 2011 and December 31, 2010, Titan had forward mark-to-market derivatives for 52.7 million and 1.7 million gallons of propane at a fair value liability of $2.0 million and a fair value asset of $0.2 million, respectively, with Enterprise. In addition, as of December 31, 2010, Titan had forward derivatives accounted for as cash flow hedges of 32.5 million gallons of propane at a fair value asset of $6.6 million with Enterprise. Our propane operations discontinued cash flow hedge accounting during the three months ended September 30, 2011; therefore, all of their forward derivatives are currently accounted for using mark-to-market accounting.

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

	September 30, 2011	December 31, 2010
Accounts receivable from related parties:		
Enterprise:		
Natural Gas Operations	$53,016	$36,736
Propane Operations	222	2,327
Other	23,659	14,803
Total accounts receivable from related parties	$76,897	$53,866
Accounts payable to related parties:		
Enterprise:		
Natural Gas Operations	$2,465	$2,687
Propane Operations	19,632	22,985
Other	4,276	1,505
Total accounts payable to related parties	$26,373	$27,177
Net imbalance (payable to) receivable from Enterprise	$(89)	$1,360

16. 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, 2011	December 31, 2010
Deposits paid to vendors	$56,435	$52,192
Prepaid expenses and other	84,991	63,077
Total other current assets	$141,426	$115,269

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

	September 30, 2011	December 31, 2010
Unamortized financing costs (3 to 30 years)	$ 41,370	$ 35,267
Regulatory assets	89,943	92,939
Other	24,172	30,400
Total non-current other assets, net	$ 155,485	$ 158,606

Accrued and Other Current Liabilities
Accrued and other current liabilities consisted of the following:

	September 30, 2011	December 31, 2010
Interest payable	$ 144,621	$ 135,867
Customer advances and deposits	109,228	86,191
Accrued capital expenditures	120,542	87,260
Accrued wages and benefits	57,243	61,587
Taxes payable other than income taxes	85,426	27,067
Income taxes payable	6,617	7,390
Other	55,725	57,198
Total accrued and other current liabilities	$ 579,402	$ 462,560

17. 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 (See Note 3); 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.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Revenues:				
Intrastate natural gas transportation and storage:				
Revenues from external customers	$617,244	$529,507	$1,849,575	$1,662,037
Intersegment revenues	33,590	369,487	245,512	952,336
	650,834	898,994	2,095,087	2,614,373
Interstate natural gas transportation — revenues from external customers	120,065	74,659	330,016	213,007
Midstream:				
Revenues from external customers	565,246	458,381	1,492,025	1,484,211
Intersegment revenues	78,742	416,703	421,154	945,438
	643,988	875,084	1,913,179	2,429,649
NGL transportation and services:				
Revenues from external customers	131,284	—	224,970	—
Intersegment revenues	15,312	—	20,446	—
	146,596	—	245,416	—
Retail propane and other retail propane related — revenues from external customers	236,781	205,833	1,037,969	987,114
All other:				
Revenues from external customers	44,696	22,264	96,433	83,962
Intersegment revenues	5,059	73,021	45,958	162,819
	49,755	95,285	142,391	246,781
Eliminations	(132,703)	(859,211)	(733,070)	(2,060,593)
Total revenues	$1,715,316	$1,290,644	$5,030,988	$4,430,331

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	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Operating income:				
Intrastate natural gas transportation and storage	$128,542	$133,750	$408,287	$395,772
Interstate natural gas transportation	67,186	34,576	169,114	98,338
Midstream	74,131	52,793	191,065	154,990
NGL transportation and services	30,935	—	59,077	—
Retail propane and other retail propane related	(27,253)	(13,053)	83,795	107,285
All other	(866)	9,009	2,822	23,695
Eliminations	(875)	(11,610)	(9,358)	(27,658)
Selling, general and administrative expenses not allocated to segments	543	2,682	1,095	(753)
Total operating income	$272,343	$208,147	$905,897	$751,669
Other items not allocated by segment:				
Interest expense, net of interest capitalized	$(124,000)	$(101,241)	$(347,706)	$(309,217)
Equity in earnings of affiliates	6,713	595	13,386	10,848
Losses on non-hedged interest rate derivatives	(68,595)	(11,963)	(64,705)	(11,963)
Allowance for equity funds used during construction	636	12,432	705	18,039
Impairment of investments in affiliates	(5,355)	—	(5,355)	(52,620)
Other income, net	(1,653)	1,410	(1,935)	(3,929)
Income tax expense	(4,039)	(1,993)	(20,419)	(12,486)
	(196,293)	(100,760)	(426,029)	(361,328)
Net income	$76,050	$107,387	$479,868	$390,341

	September 30, 2011	December 31, 2010
Total assets:		
Intrastate natural gas transportation and storage	$4,766,877	$4,894,352
Interstate natural gas transportation	3,652,595	3,390,588
Midstream	2,500,630	1,842,370
NGL transportation and services	2,183,885	—
Retail propane and other retail propane related	1,724,395	1,791,254
All other	249,666	231,428
Total	$15,078,048	$12,149,992

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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, 2010 filed with the SEC on February 28, 2011. 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 "Item 1A. Risk Factors" included in this report, in our Annual Report on Form 10-K for the year ended December 31, 2010 and in our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2010 and June 30, 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 Energy Transfer Company ("ETC OLP"); and
  - interstate natural gas transportation services through Energy Transfer Interstate Holdings, LLC ("ET Interstate"). ET Interstate is the parent company of Transwestern Pipeline Company, LLC ("Transwestern"), ETC Fayetteville Express Pipeline, LLC ("ETC FEP") and ETC Tiger Pipeline, LLC ("ETC Tiger").
- NGL transportation, storage and fractionation services primarily through Lone Star NGL LLC ("Lone Star").
- Retail propane through Heritage Operating, L.P. ("HOLP") and Titan Energy Partners, L.P. ("Titan").
- Other operations, including natural gas compression services through ETC Compression, LLC ("ETC Compression").

Recent Developments

Natural Gas Pipeline and Processing Plant

In October 2011, we entered into a long-term, fee-based agreement with XTO Energy , a subsidiary of ExxonMobil, to provide natural gas gathering, processing and transportation services from both the Woodford and Barnett Shale regions. We will construct a 117-mile, 24- and 30-inch natural gas gathering pipeline from the Woodford Shale to our existing gathering and processing infrastructure in the Barnett Shale. The pipeline will have an initial capacity of 450 MMcf/d, with anticipated capacity expansion exceeding 550 MMcf/d. The pipeline is expected to be in service by the fourth quarter of 2012. As part of the pipeline project, we will also construct a new 200 MMcf/d cryogenic processing plant at our existing Godley processing facility in Johnson County, Texas. The new processing plant will increase our processing capacity at Godley from 500 MMcf/d to 700 MMcf/d and is expected to be in service by the third quarter of 2013. The total cost to build the pipeline and processing plant is estimated to be approximately $360 million.

Propane Operations

In October 2011, we entered into an agreement with AmeriGas Partners, L.P. ("AmeriGas") to contribute our propane operations, consisting of HOLP and Titan (collectively, the "Propane Business") in exchange for consideration of approximately $2.9 billion. The consideration consists of $1.5 billion in cash and common units of AmeriGas valued at $1.32 billion, at the time of the execution of the agreement, plus the assumption of certain liabilities of the Propane Business. The transaction is subject to customary closing conditions including approval under the Hart-Scott-Rodino Act and is expected to close late 2011 or early 2012.

Citrus Transaction

On July 19, 2011, we entered into the Amended Citrus Merger Agreement pursuant to which it is anticipated that Southern Union Company, a Delaware corporation ("SUG"), will cause the contribution to us of a 50% interest in Citrus Corp., which owns 100% of the Florida Gas Transmission ("FGT") pipeline system, in exchange for approximately $1.9 billion in cash and $105 million of our Common Units, contemporaneous with the completion of the merger between SUG and ETE pursuant to the Second Amended SUG Merger Agreement as described in Note 3 to our unaudited financial statements included in this report. Citrus

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Corp. is currently jointly owned by SUG and El Paso Corporation. The FGT pipeline system has a capacity of 3.0 Bcf/d and supplied approximately 63% of the natural gas consumed in Florida for 2010. FGT's primary customers are utilities with strong investment grade credit ratings. FGT's long-term contracts with these high credit quality customers are expected to increase our fee-based revenue stream.

Tiger Pipeline Expansion

We recently completed construction of the 400 MMcf/d expansion of our Tiger pipeline. The Tiger pipeline expansion was placed in service on August 1, 2011, bringing the total capacity of the Tiger pipeline to 2.4 Bcf/d. We also began collecting demand fees from the customer who took this capacity over a 10 year term. We are currently collecting demand fees on 1.9 Bcf/d of the Tiger pipeline capacity and are scheduled to begin collecting demand fees on the entire 2.4 Bcf/d of capacity beginning January 1, 2012.

Lone Star

Lone Star announced the construction of an approximate 570-mile NGL pipeline ("West Texas Gateway Pipeline") that extends from Winkler County in west Texas to our processing plant in Jackson County, Texas which is currently under construction. In addition, Lone Star has secured capacity on our recently-announced NGL pipeline from Jackson County to Mont Belvieu, Texas. The project is expected to be completed in the first quarter of 2013 for an estimated cost of $917 million, which will be funded by contributions from us and Regency Energy Partners LP ("Regency") based on our respective ownership interests.

Joint Venture

In April 2011, we and Enterprise Products Partners L.P. (together with its subsidiaries "Enterprise") announced that we had agreed to form a 50/50 joint venture to design and construct a crude oil pipeline from Cushing, Oklahoma to Houston, Texas. In August 2011, Enterprise sent us a notice stating that Enterprise was purportedly unilaterally terminating the joint venture and Enterprise unilaterally issued a press release that the joint venture was terminated, against the objection of us and in breach of the confidentiality agreement between the parties. Enterprise subsequently announced in breach of the joint venture agreement that it and Enbridge Energy Partners, L.P. ("Enbridge") had formed a joint venture to pursue a similar crude oil pipeline project from Cushing, Oklahoma to Houston, Texas. We have initiated legal proceedings against Enterprise based on our claims of breach of contract and unfair competition and against Enbridge based on our claims of tortious interference with contractual relations.

Revolving Credit Facility

On October 27, 2011, we amended and restated the ETP Credit Facility to, among other things, (i) allow for borrowings of up to $2.5 billion; (ii) extend the maturity date from July 20, 2012 to October 27, 2016 (which may be extended by one year with lender approval); (iii) allow for an increase in the size of the credit facility to $3.75 billion (subject to obtaining lender commitments for the additional borrowings capacity); and (iv) to adjust the interest rates and commitment fees to current market terms. Following this amendment and based on our current ratings, the interest margin for LIBOR rate loans is 1.50% and the commitment fee for unused borrowing capacity is 0.25%.

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 as demonstrated by our recent acquisition of LDH Energy Asset Holdings LLC ("LDH") and recent announcements regarding organic growth projects to which we have committed. 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.

During the past several years, we have been successful in completing several transactions that have been accretive to our Unitholders. We have also made, and are continuing to make, significant investments in internal growth projects, primarily the construction of pipelines, gathering systems and natural gas treating and processing plants, which we believe will provide additional cash flow to our Partnership for years to come. In addition, we have recently announced transactions that will expand the scope of our business to include natural gas liquids storage and fractionation and transportation.

Our principal operations include 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 primarily impact our interruptible business are primarily among receipt points between West Texas to East Texas or segments thereof. When narrow or flat spreads exist, our open capacity may be underutilized and go unsold.

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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 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.

- 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. Tiger, Fayetteville Express Pipeline LLC ("FEP") and Transwestern expansion shippers have made 10- to 15-year commitments to pay reservation charges for the firm capacity reserved for their use. 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.

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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.

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 percent of proceeds and income sharing contracts, which are subject to market pricing of olefins and NGLs. For percent 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 – Revenue is principally generated from the sale of propane and propane-related products and services. The retail propane segment is a margin-based business in which gross profits depend on the excess of sales price over propane supply cost. Consequently, the profitability of our retail propane business is sensitive to changes in wholesale propane prices. Our propane business is largely seasonal and dependent upon weather conditions in our service areas. We use information published by the National Oceanic and Atmospheric Administration ("NOAA") to gather heating degree day data to analyze how our sales volumes may be affected by temperature. Our normal temperatures are defined as the prior ten year weighted-average temperature which is based on the average heating degree days provided by NOAA gathered from the various measuring points in our operating areas weighted by the retail volumes attributable to each measuring point.

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Results of Operations
Consolidated Results

	Three Months Ended September 30, 2011	2010	Change	Nine Months Ended September 30, 2011	2010	Change
Revenues	$1,715,316	$1,290,644	$424,672	$5,030,988	$4,430,331	$600,657
Cost of products sold	1,075,526	777,411	298,115	3,078,611	2,773,133	305,478
Gross margin	639,790	513,233	126,557	1,952,377	1,657,198	295,179
Operating expenses	196,737	174,740	21,997	574,528	515,021	59,507
Depreciation and amortization	112,942	85,612	27,330	313,878	252,765	61,113
Selling, general and administrative	57,768	44,734	13,034	158,074	137,743	20,331
Operating income	272,343	208,147	64,196	905,897	751,669	154,228
Interest expense, net of interest capitalized	(124,000)	(101,241)	(22,759)	(347,706)	(309,217)	(38,489)
Equity in earnings of affiliates	6,713	595	6,118	13,386	10,848	2,538
Losses on non-hedged interest rate derivatives	(68,595)	(11,963)	(56,632)	(64,705)	(11,963)	(52,742)
Allowance for equity funds used during construction	636	12,432	(11,796)	705	18,039	(17,334)
Impairment of investments in affiliates	(5,355)	—	(5,355)	(5,355)	(52,620)	47,265
Other, net	(1,653)	1,410	(3,063)	(1,935)	(3,929)	1,994
Income tax expense	(4,039)	(1,993)	(2,046)	(20,419)	(12,486)	(7,933)
Net income	76,050	107,387	(31,337)	479,868	390,341	89,527
Less: Net income attributable to noncontrolling interest	9,285	—	9,285	17,673	—	17,673
Net income attributable to partners	$66,765	$107,387	$(40,622)	$462,195	$390,341	$71,854

See the detailed discussion of operating income by operating segment below.

Interest Expense. Interest expense increased for the three and nine months ended September 30, 2011 compared to the same periods last year principally due to the issuance of $1.5 billion of senior notes in May 2011, the proceeds from which were used to repay borrowings on our revolving credit facility, to fund growth projects and for general partnership purposes. Interest expense was presented net of capitalized interest and allowance for debt funds used during construction, which totaled $4.3 million and $7.1 million for the three months ended September 30, 2011 and 2010, respectively, and $9.5 million and $11.0 million for the nine months ended September 30, 2011 and 2010, respectively.

Equity in Earnings of Affiliates. Equity in earnings of affiliates for the three and nine months ended September 30, 2011 primarily reflected equity in earnings related to FEP. Equity in earnings of affiliates for the nine months ended September 30, 2010 were primarily related to MEP, for which substantially all of our interest was transferred on May 26, 2010 to Regency.

Losses on Non-Hedged Interest Rate Derivatives. Losses on non-hedged interest rate derivatives for the three and nine months ended September 30, 2011 reflected settlements and unrealized gains and losses on our interest rate swaps. As of September 30, 2011, we had a total notional amount of $1.65 billion of interest rate swaps outstanding compared to $400 million as of September 30, 2010. The $1.65 billion of swaps included $1.15 billion of forward-starting floating-to-fixed swaps used to hedge interest rates associated with anticipated note issuances, and $500 million of fixed-to-floating swaps used to swap a portion of our fixed rate debt to floating. During the three months ended September 30, 2011, forward rates decreased significantly due to the global economic uncertainty which resulted in

unrealized non-cash losses on our forward-starting floating-to-fixed swaps.
Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction for the three and nine months ended September 30, 2011 reflected amounts recorded in connection with the expansion of the Tiger Pipeline which was completed in August 2011, whereas the same periods in the prior year reflected amounts recorded in connection with the original construction of the Tiger Pipeline.

Impairment of Investments in Affiliates. For the three and nine months ended September 30, 2011, our results reflected a non-cash charge to write off all of our investment in a joint venture for which projects are no longer being pursued. In conjunction with the transfer of our interest in MEP on May 26, 2010, we recorded a non-cash charge of approximately $52.6 million during the nine months ended September 30, 2010 to reduce the carrying value of our interest to its estimated fair value.

Income Tax Expense. The increase in income tax expense between the periods was primarily due to increases in taxable income within our subsidiaries that are taxable corporations, as well as an increase in amounts recorded for the Texas margins tax resulting from increased operating income.

Noncontrolling Interest. The increase in noncontrolling interest was related to Regency's 30% interest in Lone Star which was included in our consolidated financial information.

Segment Operating Results

We evaluate segment performance based on operating income (either in total or by individual segment), 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.

Detailed descriptions of our business and segments are included in our Annual Report on Form 10-K for the year ended December 31, 2010 filed with the SEC on February 28, 2011. In addition, following the acquisition of all of the membership interests in LDH on May 2, 2011, we have added an NGL transportation and services segment, which includes all of Lone Star’s results of operations. We had initially included Lone Star’s 20% investment in a processing plant in our interim financial statements as of and for the period ended June 30, 2011 in the midstream segment; however, that investment is now reflected in our NGL transportation and services segment as well for all post-acquisition periods, in order to conform our segment presentation to the same level of data that our executive management and chief operating decision maker has chosen to review.

Operating income (loss) by segment is as follows:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
Intrastate transportation and storage	$128,542	$133,750	$(5,208)	$408,287	$395,772	$12,515
Interstate transportation	67,186	34,576	32,610	169,114	98,338	70,776
Midstream	74,131	52,793	21,338	191,065	154,990	36,075
NGL transportation and services	30,935	—	30,935	59,077	—	59,077
Retail propane and other retail propane related	(27,253)	(13,053)	(14,200)	83,795	107,285	(23,490)
All other	(866)	9,009	(9,875)	2,822	23,695	(20,873)
Eliminations	(875)	(11,610)	10,735	(9,358)	(27,658)	18,300
Selling, general and administrative expenses not allocated to segments	543	2,682	(2,139)	1,095	(753)	1,848
Operating income	$272,343	$208,147	$64,196	$905,897	$751,669	$154,228

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, 2011	2010	Change	Nine Months Ended September 30, 2011	2010	Change
Natural gas transported (MMBtu/d)	11,148,186	13,250,836	(2,102,650)	11,367,812	12,132,099	(764,287)
Revenues	$650,834	$898,994	$(248,160)	$2,095,087	$2,614,373	$(519,286)
Cost of products sold	422,801	660,107	(237,306)	1,396,001	1,930,798	(534,797)
Gross margin	228,033	238,887	(10,854)	699,086	683,575	15,511
Operating expenses	49,336	56,167	(6,831)	144,631	145,497	(866)
Depreciation and amortization	29,975	29,340	635	89,412	87,484	1,928
Selling, general and administrative	20,180	19,630	550	56,756	54,822	1,934
Segment operating income	$128,542	$133,750	$(5,208)	$408,287	$395,772	$12,515

Volumes. We experienced a decrease in transported volumes for the three and nine months ended September 30, 2011. This was due to an unfavorable natural gas price environment and lower basis differentials between the West and East Texas market hubs. The average spot price difference between these locations was $0.05/MMBtu during the three months ended September 30, 2011 compared to $0.25/MMBtu during the three months ended September 30, 2010. The average spot price difference between these locations was $0.04/MMBtu during the nine months ended September 30, 2011 compared to $0.14/MMBtu during the nine months ended September 30, 2010.
Gross Margin. The components of our intrastate transportation and storage segment gross margin were as follows:

	Three Months Ended September 30, 2011	2010	Change	Nine Months Ended September 30, 2011	2010	Change
Transportation fees	$148,331	$152,223	$(3,892)	$448,669	$447,775	$894
Natural gas sales and other	42,981	27,504	15,477	106,570	83,464	23,106
Retained fuel revenues	32,560	35,930	(3,370)	104,222	109,017	(4,795)
Storage margin, including fees	4,161	23,230	(19,069)	39,625	43,319	(3,694)
Total gross margin	$228,033	$238,887	$(10,854)	$699,086	$683,575	$15,511

For the three months ended September 30, 2011 compared to the three months ended September 30, 2010, intrastate transportation and storage gross margin decreased primarily due to the following factors:

- The decrease in transportation fees for the three months ended September 30, 2011 was primarily due to lower transported volumes compared to the three months ended September 30, 2010, as discussed above.

- Margin from the sales of natural gas and other increased by $15.5 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010, primarily due to an increase in wellhead margin and transported volume on our HPL system of $2.9 million, as well as commodity-related derivative activity which resulted in a net favorable impact between periods of $9.3 million. Excluding storage-related derivatives, we recorded unrealized gains of $4.0 million during the three months ended September 30, 2011 compared to gains of $0.6 million during the three months ended September 30, 2010, and realized gains increased $5.9 million between periods.

- Retained fuel revenues include gross volumes retained as a fee at the current market price; the cost of consumed fuel is included in operating expenses. For the three months ended September 30, 2011 compared to the three months ended September 30, 2010, retention revenue decreased $3.4 million due to less retained volumes and a decrease in natural gas spot prices. Spot prices averaged $4.12/MMBtu for the three months ended September 30, 2011 compared to an average of $4.19/MMBtu for the three months ended September 30, 2010.

For the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, intrastate transportation and storage gross margin increased primarily due to the following factors:

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- The slight increase for the nine months ending September 30, 2011 was mainly due to demand fee increases offset by lower transported volumes.

- For the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, retention revenue decreased $4.8 million due to lower retained volumes and a decrease in natural gas prices. Our average price for retained natural gas during the nine months ended September 30, 2011 was $4.20/MMBtu compared to $4.33/MMBtu for the nine months ended September 30, 2010.

- Margin from the sales of natural gas and other increased by $23.1 million during the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, resulting from an increase of $6.7 million from sales of NGLs and an $18.0 million increase from commodity-related derivative activity. The increases were offset by a $4.3 million decrease in margin from system optimization activities. Excluding storage-related derivatives, we recorded unrealized gains of $4.1 million during the nine months ended September 30, 2011 compared to losses of $16.3 million during the nine months ended September 30, 2010.

From time to time, our marketing affiliate will contract with our intrastate pipelines for long-term and interruptible capacity. Our intrastate transportation and storage segment recorded intercompany transportation fees from our marketing affiliate of $9.0 million and $10.8 million for the three months ended September 30, 2011 and 2010, respectively. For the nine months ended September 30, 2011, our intrastate and storage segment has recorded $27.0 million as compared to $30.7 million for the nine months ending September 30, 2010. These decreases between periods are primarily due to less capacity utilization by our marketing affiliate over the respective periods.
Storage margin was comprised of the following:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
Withdrawals from storage natural gas inventory (MMBtu)	8,661,359	7,459,977	1,201,382	24,433,485	35,347,967	(10,914,482)
Margin on physical sales	$154	$2,397	$(2,243)	$10,845	$68,049	$(57,204)
Settlements of derivatives	5,421	(8,479)	13,900	5,992	(17,408)	23,400
Realized margin on natural gas inventory transactions	5,575	(6,082)	11,657	16,837	50,641	(33,804)
Fair value inventory adjustments	(27,603)	(7,908)	(19,695)	(22,772)	(70,162)	47,390
Unrealized gains on derivatives	18,231	27,867	(9,636)	20,024	33,161	(13,137)
Margin recognized on natural gas inventory and related derivatives	(3,797)	13,877	(17,674)	14,089	13,640	449
Revenues from fee-based storage	8,072	9,286	(1,214)	25,891	30,913	(5,022)
Other costs	(114)	67	(181)	(355)	(1,234)	879
Total storage margin	$4,161	$23,230	$(19,069)	$39,625	$43,319	$(3,694)

In addition to fee based contracts, our storage margin is also impacted by the price variance between the carrying amount of our inventory and the locked-in sales price of our financial derivatives. We apply fair value hedge accounting to the natural gas we purchase for storage and adjust the carrying amount of our inventory to the spot price at the end of each period. These inventory fair value adjustments are offset by a portion of the unrealized gains or losses on the related financial derivative. These changes in value occur until the settlement of the derivative or the actual withdrawal of the inventory, when the earnings are realized. The unrealized gains and losses that we recognize represent the change in the spread between the spot price and the forward price. This spread can widen or narrow, thereby creating unrealized losses or gains, until ultimately converging when the financial contract settles.

For the three months ended September 30, 2011, storage margin decreased by $19.1 million primarily due to changes in the spread between spot price and the forward prices which resulted in non-cash adjustments of $27.6 million during the three months ended September 30, 2011 compared to $7.9 million for the three months ended September 30, 2010. Storage margins for the three months ended September 30, 2011 and 2010 were also impacted by the timing of financial derivative settlements as a result of optimizing the withdrawals of stored natural gas inventory.

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For the nine months ended September 30, 2011, storage margin decreased by $3.7 million primarily due to a decrease in fee-based storage from the nine months ending September 30, 2010.

Operating Expenses. For the three months ended September 30, 2011, intrastate transportation and storage operating expenses decreased by $6.8 million principally due to a decrease in natural gas consumed for compression of $3.2 million, a decrease in maintenance and operating expenses of $2.2 million and a decrease in ad valorem tax of $1.4 million. For the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, intrastate operating expenses decreased by $0.9 million, which reflects a decrease in maintenance and operating expenses of $1.5 million, offset by an increase in the cost of natural gas consumed of $0.7 million.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased during the three months ended September 30, 2011 compared to the prior periods primarily due to the completion of pipeline projects in connection with the continued expansion of our pipeline system.

Selling, General and Administrative. Intrastate selling, general and administrative expenses increased for the three and nine months ended September 30, 2011 as a result of an increase in employee related costs (including allocated overhead expenses).

Interstate Transportation

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
Natural gas transported (MMBtu/d)	3,155,559	1,807,012	1,348,547	2,709,522	1,625,469	1,084,053
Natural gas sold (MMBtu/d)	21,808	24,282	(2,474)	22,859	23,027	(168)
Revenues	$120,065	$74,659	$45,406	$330,016	$213,007	$117,009
Operating expenses	21,459	19,886	1,573	73,874	56,147	17,727
Depreciation and amortization	20,298	12,643	7,655	59,368	37,856	21,512
Selling, general and administrative	11,122	7,554	3,568	27,660	20,666	6,994
Segment operating income	$67,186	$34,576	$32,610	$169,114	$98,338	$70,776

The interstate transportation segment data presented above does not include our interstate pipeline joint ventures, for which we reflect our proportionate share of income within “Equity in earnings of affiliates” below operating income in our consolidated statement of operations. We recorded equity in earnings related to FEP of $5.9 million and $11.9 million for the three and nine months ended September 30, 2011. We recorded equity in earnings related to MEP of $8.9 million for the nine months ended September 30, 2010. As discussed above, we transferred substantially all of our interest in MEP on May 26, 2010 and transferred our remaining 0.1% interest in MEP on September 1, 2011 to Regency.

Volumes. Transported volumes for our interstate transportation segment increased compared to the same periods in the prior year due to transported volumes of 1,533,666 MMBtu/d and 1,198,642 MMBtu/d for the three and nine months ended September 30, 2011, respectively, on the Tiger pipeline, which was placed in service in December 2010 with an additional expansion placed in service on August 1, 2011. For both the three and nine months ended September 30, 2011, the incremental transported volumes related to the Tiger pipeline were offset by lower volumes on the Transwestern pipeline compared to the same period in the prior year.

Revenues. Interstate transportation revenues increased compared to the same periods in the prior year primarily as a result of $52.4 million and $132.1 million for the three and nine months ended September 30, 2011, respectively, related to the Tiger pipeline. The increases for the three and nine months ended September 30, 2011 were partially offset by decreased revenue from the Transwestern pipeline as a result of lower margins and volumes on natural gas transported and sold.

Operating Expenses. Interstate transportation operating expenses increased during the three and nine months ended September 30, 2011 compared to the same periods in the prior year primarily due to operating expenses incurred on the Tiger pipeline.

Depreciation and Amortization. Interstate transportation depreciation and amortization expense increased during the three and nine months ended September 30, 2011 compared to the same periods in the prior year primarily due to incremental depreciation associated with the Tiger pipeline.

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Selling, General and Administrative. Interstate transportation selling, general and administrative expenses increased during the three and nine months ended September 30, 2011 compared to the same periods in the prior year primarily due to increased allocated and employee-related expenses related to the Tiger pipeline.

Midstream

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
NGLs produced (Bbls/d)	56,638	53,004	3,634	52,398	50,836	1,562
Equity NGLs produced (Bbls/d)	16,772	20,670	(3,898)	16,604	19,697	(3,093)
Revenues	$643,988	$875,084	$(231,096)	$1,913,179	$2,429,649	$(516,470)
Cost of products sold	513,256	775,769	(262,513)	1,552,453	2,138,125	(585,672)
Gross margin	130,732	99,315	31,417	360,726	291,524	69,202
Operating expenses	21,303	19,734	1,569	70,406	56,597	13,809
Depreciation and amortization	28,344	21,592	6,752	79,658	62,209	17,449
Selling, general and administrative	6,954	5,196	1,758	19,597	17,728	1,869
Segment operating income	$74,131	$52,793	$21,338	$191,065	$154,990	$36,075

Volumes. NGL production increased during the three months ended September 30, 2011 primarily due to increased inlet volumes at our La Grange plant as a result of more production in the Eagle Ford area offset by reduced inlet volumes at our Godley plant as a result of lower production in the North Texas 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, 2011 as compared to the same period last year.

NGL production increased during the nine months ended September 30, 2011 primarily due to increased inlet volumes at our La Grange plant as a result of more production by our customers in the Eagle Ford Shale in addition to favorable processing conditions. The decrease in equity NGL production was primarily due to a higher concentration of volumes under fee-based contracts during the nine months ended September 30, 2011 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,		
	2011	2010	Change	2011	2010	Change
Gathering and processing fee-based revenues	$68,130	$55,840	$12,290	$193,726	$165,718	$28,008
Non fee-based contracts and processing	68,281	48,799	19,482	179,229	146,295	32,934
Other	(5,679)	(5,324)	(355)	(12,229)	(20,489)	8,260
Total gross margin	$130,732	$99,315	$31,417	$360,726	$291,524	$69,202

For the three months ended September 30, 2011, midstream gross margin increased compared to the same period last year due to the following:

- Increased volumes primarily from production in the Eagle Ford Shale resulted in increased fee-based revenues of $6.8 million for the three months ended September 30, 2011 as compared with the same period last year. Additionally, increased volumes resulting from growth projects located in Louisiana and West Virginia provided an increase in our fee-based margin of $6.3 million for the three months ended September 30, 2011 as compared with the same period last year.
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Our non fee-based gross margins increased $19.5 million primarily due to favorable NGL prices. The composite NGL price increased for the three months ended September 30, 2011 to $1.33 per gallon from $0.91 per gallon during the three months ended September 30, 2010. Lower equity NGL production volumes as discussed above partially offset the increase in NGL prices activity.

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For the nine months ended September 30, 2011, midstream gross margin increased compared to the same period last year due to the following:

- Increased volumes from production in the Eagle Ford area and in our North Texas system resulted in increased fee-based revenues of $14.5 million for the nine months ended September 30, 2011 as compared with the same period last year. Additionally, increased volumes resulting from growth projects located in Louisiana and West Virginia provided an increase in our fee-based margin of $14.5 million for the nine months ended September 30, 2011 as compared with the same period last year.
- Our non fee-based gross margins increased $32.9 million primarily due to favorable NGL prices. The composite NGL price increased for the nine months ended September 30, 2011 to $1.29 per gallon from $1.00 per gallon during the nine months ended September 30, 2010. Lower equity NGL production volumes, as discussed above, partially offset the increase in NGL prices.
- The increase in other midstream gross margin was due to an increase in processing margin of $8.1 million where third party processing capacity was utilized. Other midstream gross margin included unrealized gains on derivatives of $2.1 million during the nine months ended September 30, 2011 compared to unrealized losses of $11.6 million during the nine months ended September 30, 2010.

Operating Expenses. For the three months ended September 30, 2011 compared to the three months ended September 30, 2010, midstream operating expenses reflected an increase in maintenance and operating expenses of $4.0 million offset by a decrease of $2.4 million in ad valorem taxes. For the nine months ended September 30, 2011 compared to the nine months ended September 30, 2010, midstream operating expenses reflected increases of $2.5 million in ad valorem taxes, $4.0 million in employee expenses, $2.0 million in professional fees and $5.3 million in maintenance and operating costs.

Depreciation and Amortization. Midstream depreciation and amortization expense increased between the periods primarily due to incremental depreciation from the continued expansion of our Louisiana and South Texas assets.

Selling, General and Administrative. Midstream selling, general and administrative expenses increased $1.8 million for the three months ended September 30, 2011 compared to the three months ended September 30, 2010 primarily due to an increase in employee-related expenses. For the nine months ended September 30, 2011 our expenses increased $1.9 million compared to the comparable period due to an increase professional fees and other expenses of $5.4 million offset by a reduction in employee costs of $3.5 million.

NGL Transportation and Services

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
NGL transportation volumes (Bbls/d)	133,149	—	133,149	131,147	—	131,147
NGL fractionation volumes (Bbls/d)	13,833	—	13,833	14,912	—	14,912
Revenues	$146,596	$—	$146,596	$245,416	$—	$245,416
Cost of products sold	81,224	—	81,224	133,628	—	133,628
Gross margin	65,372	—	65,372	111,788	—	111,788
Operating expenses	16,575	—	16,575	23,062	—	23,062
Depreciation and amortization	12,904	—	12,904	20,043	—	20,043
Selling, general and administrative	4,958	—	4,958	9,606	—	9,606
Segment operating income	$30,935	$—	$30,935	$59,077	$—	$59,077

We own a controlling interest in Lone Star, which acquired all of the membership interests in LDH on May 2, 2011. Results reflected above represent 100% of those of acquired businesses that are engaged in NGL transportation, storage and fractionation from May 2, 2011 to September 30, 2011.

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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,		
	2011	2010	Change	2011	2010	Change
Storage revenues	$34,287	$—	34,287	$57,702	$—	$57,702
Transportation revenues	13,646	—	13,646	20,696	—	20,696
Processing and fractionation revenues	16,602	—	16,602	33,324	—	33,324
Other revenues	837	—	837	66	—	66
Total gross margin	$65,372	$—	$65,372	$111,788	$—	$111,788

Retail Propane and Other Retail Propane Related

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Change	2011	2010	Change
Retail propane gallons (in thousands)	84,193	85,722	(1,529)	372,494	388,306	(15,812)
Retail propane revenues	$213,496	$183,786	$29,710	$962,258	$914,372	$47,886
Other retail propane related revenues	23,285	22,047	1,238	75,711	72,742	2,969
Retail propane cost of products sold	141,868	104,533	37,335	587,460	519,796	67,664
Other retail propane related cost of products sold	5,357	5,377	(20)	14,657	15,004	(347)
Gross margin	89,556	95,923	(6,367)	435,852	452,314	(16,462)
Operating expenses	84,655	75,990	8,665	252,520	247,692	4,828
Depreciation and amortization	20,248	20,609	(361)	61,676	60,994	682
Selling, general and administrative	11,906	12,377	(471)	37,861	36,343	1,518
Segment operating income	$(27,253)	$(13,053)	$(14,200)	$83,795	$107,285	$(23,490)

Volumes. For the three months ended September 30, 2011, sales volumes were 1.5 million gallons below the same period last year. The combined average temperatures in our operating areas were approximately 17.4% warmer than normal as compared to weather which was approximately 10.6% warmer than normal during the same period in 2010.

For the nine months ended September 30, 2011, sales volumes were 15.8 million gallons below the same period last year. The combined average temperatures in our operating areas were approximately 3.0% colder than normal as compared to weather which was approximately 3.6% colder than normal during the same period in 2010.

The combination of weather patterns along with continued customer conservation negatively impacted our sales volumes for both the three and nine months ended September 30, 2011 compared to the same periods last year.

Gross Margin. Total gross margin decreased $6.4 million during the three months ended September 30, 2011 compared to the same period last year primarily due to a decrease of $4.2 million in retail fuel margins related to a decline in the average gross margin per gallon sold as well as a decrease of $1.4 million due to the volume decrease discussed above. Total gross margin also decreased $2.0 million due to an unfavorable non-cash impact between periods attributable to mark-to-market adjustments for our financial instruments used in our commodity price risk management activities. These decreases were partially offset by a $1.3 million increase in other retail propane related gross profit.

Total gross margin decreased $16.5 million during the nine months ended September 30, 2011 compared to the same period last year primarily due to a decrease of $4.7 million in retail fuel margins related to a decline in the average gross margin per gallon sold as well as a decrease of $16.2 million due to the volume decrease discussed above. These decreases were partially offset by a $1.1 million favorable non-cash impact between periods attributable to mark-to-market adjustments for our financial instruments used in our commodity price risk management activities and a $3.3 million increase in other retail propane related gross profit.

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Operating Expenses. Operating expenses were higher for the three months ended September 30, 2011 compared to the same period last year primarily due to increases of $3.8 million in net business insurance reserves and claims and $2.3 million in vehicle fuel and repair expenses.

Operating expenses were higher for the nine months ended September 30, 2011 compared to the same period last year primarily due to increases of $5.6 million in vehicle fuel and repair expenses, $2.8 million in net business insurance reserves and claims, $1.9 million in employee wages and benefits and $1.0 million in general business taxes. These increases were partially offset by decreases of $5.6 million in performance-based bonus accruals and $2.7 million in other general operating expenses.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses for the nine months ended September 30, 2011 compared to the same period last year was primarily related to increases in employee wages and benefits and expenses related to one-time debt agreement amendments. These increases were partially offset by a decrease in non-cash unit-based compensation expense of $0.6 million primarily due to forfeited unit awards during the current year and decreases in allocated overhead expenses of $0.6 million.

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:

- 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 $250 million for the remainder of 2011 and between $600 million and $750 million for 2012;
- growth capital expenditures for our interstate transportation segment, excluding capital contributions to our joint ventures as discussed below, for the construction of new pipelines for which we expect to spend between $5 million and $10 million for the remainder of 2011;
- growth capital expenditures for our NGL transportation and services segment of between $250 million and $300 million for the remainder of 2011 and between $700 million and $750 million for 2012;
- growth capital expenditures for our retail propane segment of between $10 million and $20 million for the remainder of 2011; and
- maintenance capital expenditures of between $40 million and $50 million for the remainder of 2011, 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; (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; and (iv) capital expenditures for our propane operations to extend the useful lives of our existing propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet. We also except to spend between $120 million and $130 million in maintenance capital expenditures for 2012.

As discussed in Note 3 to our unaudited financial statements included in this report, we entered into the Amended Citrus Merger Agreement on July 19, 2011. We expect to fund substantially all of the cash portion of the purchase price initially through the issuance of debt and borrowing from the ETP Credit Facility. In turn, ETE will use these proceeds to repay a substantial portion of the acquisition financing incurred by ETE to fund the cash consideration to be paid to SUG shareholders. ETP also intends to issue sufficient additional equity to maintain its investment grade credit rating and to use the proceeds from such equity issuances to repay other indebtedness and fund capital expenditures. In addition, we may enter into other acquisitions, including the potential acquisition of new pipeline systems.

We generally fund our capital requirements with cash flows from operating activities and, to the extent that they exceed cash flows from operating activities, with proceeds of borrowings under existing credit facilities, long-term debt, the issuance of additional Common Units or a combination thereof. We raised $695.5 million in net proceeds from our Common Unit offering in April 2011 and $7.6 million in net proceeds from the issuance of 175,863 Common Units in connection with our distribution reinvestment plan ("DRIP") in 2011. In addition, we raised $96.3 million in net proceeds during the nine months ended September 30, 2011 under our equity distribution program, as described in Note 10 to our consolidated financial statements. As of September 30, 2011, in addition to $136.2 million of cash on hand, we had available capacity under the ETP Credit Facility of $1.40 billion. 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 through the end of 2011; 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.

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 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 propane and natural gas inventories, and the timing of advances and deposits received from customers.

Nine months ended September 30, 2011 compared to nine months ended September 30, 2010. Cash provided by operating activities during 2011 was $1.03 billion as compared to $1.10 billion for 2010 and net income was $479.9 million and $390.3 million for 2011 and 2010, respectively. The difference between net income and cash provided by operating activities for the nine months ended September 30, 2011 and 2010 primarily consisted of non-cash items totaling $358.8 million and $324.0 million, respectively, and changes in operating assets and liabilities of $195.0 million and $344.7 million, respectively.

The non-cash activity in 2011 and 2010 consisted primarily of depreciation and amortization of $313.9 million and $252.8 million, respectively. In addition, non-cash compensation expense was $31.1 million and $22.4 million for 2011 and 2010, respectively. The nine months ended September 30, 2010 also reflect a non-cash impairment at $52.6 million on our investment in MEP prior to our transfer of substantially all of our investment to Regency on May 26, 2010.

Cash paid for interest, net of interest capitalized, was $345.4 million and $345.5 million for the nine months ended September 30, 2011 and 2010, respectively.

Investing Activities

Cash flows from investing activities primarily consist of cash amounts paid in acquisitions, capital expenditures, and cash contributions to our joint ventures. 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, 2011 compared to nine months ended September 30, 2010. Cash used in investing activities during 2011 was $3.10 billion as compared to $1.17 billion for 2010. Total capital expenditures (excluding the allowance for equity funds used during construction) for 2011 were $951.0 million, including changes in accruals of $34.4 million. This compares to total capital expenditures (excluding the allowance for equity funds used during construction) for 2010 of $1.04 billion, including changes in accruals of $37.0 million. In addition, 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. We paid cash for acquisitions of $156.4 million and made advances to our joint ventures of $6.0 million during 2010.

Growth capital expenditures for 2011, before changes in accruals, were $744.5 million for our midstream, intrastate transportation and storage and NGL 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, intrastate transportation and storage and NGL segments, $15.3 million related to our interstate transportation segment and $19.6 million related to our retail propane and all other segments.
Growth capital expenditures for 2010, before changes in accruals, were $265.9 million for our midstream and intrastate transportation and storage segments, $711.6 million for our interstate transportation segment, and $26.1 million for our retail

propane and all other segments. We also incurred $70.3 million in maintenance capital expenditures, of which $31.8 million related to our midstream and intrastate transportation and storage segments, $16.1 million related to our interstate transportation segment and $22.4 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, 2011 compared to nine months ended September 30, 2010. Cash provided by financing activities during 2011 was $2.16 billion as compared to cash provided by financing activities of $80.2 million for 2010. In 2011, we received $799.3 million in net proceeds from Common Unit offerings, including $96.3 million under our equity distribution program (see Note 10 to our consolidated financial statements) as compared to net proceeds from Common Unit offerings of $1.09 billion in 2010, which included $174.1 million under our equity distribution program. 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 2011, we had a net increase in our debt level of $1.64 billion as compared to a net decrease of $197.7 million for 2010, primarily due to our issuance of $1.50 billion principal amount of senior notes in May 2011 to partially fund the LDH Acquisition. In connection with the issuance of senior notes in May 2011, we incurred debt issuance costs of $12.3 million. We paid distributions of $863.5 million to our partners in 2011 as compared to $794.8 million in 2010. In addition, we received a capital contribution of $616.3 million from Regency for its noncontrolling interest in LDH as compared to no contributions received in 2010.

Description of Indebtedness

Our outstanding consolidated indebtedness was as follows:

	September 30, 2011	December 31, 2010
ETP Senior Notes	$6,550,000	$5,050,000
Transwestern Senior Unsecured Notes	870,000	870,000
HOLP Senior Secured Notes	73,314	103,127
Revolving credit facilities	574,607	402,327
Other long-term debt	11,145	9,541
Unamortized discounts	(15,723)	(12,074)
Fair value adjustments related to interest rate swaps	13,051	17,260
Total debt	8,076,394	6,440,181
Less: current maturities	424,076	35,265
Long-term debt, less current maturities	$7,652,318	$6,404,916

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, 2010, filed with the SEC on February 28, 2011 and in Note 9 to our consolidated financial statements.

The $6.55 billion of aggregate principal amount of ETP Senior Notes includes $600 million of principal amount of 9.7% Senior Notes due March 15, 2019. The holders of those notes will have the right to require us to repurchase all or a portion of the notes on March 15, 2012 at a purchase price of equal to 100% of the principal amount (par value) of the notes tendered. The current market value of the notes is significantly in excess of the principal amount, making a repurchase at par value uneconomic by the holder. However, if such a repurchase were to occur, we would intend to refinance any amounts paid on a long-term basis.

Revolving Credit Facility

The indebtedness under ETP's revolving 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.

As of September 30, 2011, we had $574.6 million outstanding under the ETP Credit Facility, and the amount available for future borrowings was $1.40 billion taking into account letters of credit of $24.3 million. The weighted average interest rate on the total amount outstanding as of September 30, 2011 was 0.80%.

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On October 27, 2011, we amended and restated the ETP Credit Facility to, among other things, (i) allow for borrowings of up to $2.5 billion; (ii) extend the maturity date from July 20, 2012 to October 27, 2016 (which may be extended by one year with lender approval); (iii) allow for an increase in the size of the credit facility to $3.75 billion (subject to obtaining lender commitments for the additional borrowing capacity); and (iv) to adjust the interest rates and commitment fees to current market terms. Following this amendment and based on our current ratings, the interest margin for LIBOR rate loans is 1.50% and the commitment fee for unused borrowing capacity is 0.25%.

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, 2011.

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, 2010:

Quarter Ended	Record Date	Payment Date	Rate
December 31, 2010	February 7, 2011	February 14, 2011	$0.89375
March 31, 2011	May 6, 2011	May 16, 2011	0.89375
June 30, 2011	August 5, 2011	August 15, 2011	0.89375
September 30, 2011	November 4, 2011	November 14, 2011	0.89375

The total amounts of distributions declared during the nine months ended September 30, 2011 and 2010 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,	
	2011	2010
Limited Partners:		
Common Units	$560,281	$503,582
Class E Units	9,363	9,363
General Partner interest	14,690	14,634
Incentive Distribution Rights	310,254	279,823
Total distributions declared	$894,588	$807,402

New Accounting Standards

In September 2011, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2011-08, Intangibles - Goodwill and Other (Topic 350): Testing Goodwill for Impairment (“ASU 2011-08”), which simplifies how entities test goodwill for impairment. ASU 2011-08 gives entities the option, under certain circumstances, to first assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount as a basis for determining whether further impairment testing is necessary. ASU 2011-08 is effective for fiscal years beginning after December 15, 2011, and early adoption is permitted. We are currently evaluating early adoption of ASU 2011-08, but we do not expect adoption of this standard will materially impact our financial position or results of operations.

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, 2010.

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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, 2010, in addition to the interim unaudited consolidated financial statements, 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, 2010. Since December 31, 2010, there have been no material changes to our primary market risk exposures or how those exposures are managed.

The United States Congress recently 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. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also 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 us to comply with 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. 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, 2011 and December 31, 2010, 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 and gallons for propane. Dollar amounts are presented in thousands.

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	September 30, 2011			December 31, 2010		
	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						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(39,952,500)	$ 6,225	$ 906	(38,897,500)	$ (2,334)	$ 304
Swing Swaps IFERC	30,517,500	(889)	2,323	(19,720,000)	(2,086)	2,228
Fixed Swaps/Futures	(15,517,500)	(9,730)	6,073	(2,570,000)	(11,488)	1,176
Forward Physical Contracts	12,324,054	255	1,210	—	—	—
Options – Calls	—	—	—	(3,000,000)	62	7
Propane:						
Forwards/Swaps	52,668,000	(2,008)	7,685	1,974,000	275	258
Fair Value Hedging Derivatives						
Natural Gas:						
Basis Swaps IFERC/NYMEX	(19,685,000)	(251)	167	(28,050,000)	722	322
Fixed Swaps/Futures	(29,837,500)	30,695	12,267	(39,105,000)	8,599	16,837
Cash Flow Hedging Derivatives						
Natural Gas:						
Fixed Swaps/Futures	460,000	4	204	(210,000)	232	93
Options – Puts	9,390,000	8,955	3,220	26,760,000	10,545	7,125
Options – Calls	(9,390,000)	2,587	67	(26,760,000)	4,812	1,565
Propane:						
Forwards/Swaps	—	—	—	32,466,000	6,589	4,196

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, 2011, we had $574.6 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 $5.7 million annually. We manage a portion of our interest rate exposure by utilizing interest rate swaps and similar arrangements. 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, 2011 and December 31, 2010, none of which are designated as hedges for accounting purposes:

Term	Type (1)	Notional Amount Outstanding September 30, 2011	December 31, 2010
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	400,000
July 2013(2)	Forward starting to pay a fixed rate of 4.02% and receive a floating rate	300,000	—
July 2018	Pay a floating rate plus a spread of 4.01% and receive a fixed rate of 6.70%	500,000	500,000

(1) As of September 30, 2011. Floating rates are based on 3-month LIBOR.

(2) 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 $80.3 million as of September 30, 2011 and $0.3 million as of December 31, 2010. For the $500 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 $5.0 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 counterparty.

Our counterparties consist primarily of petrochemical companies and other industrials, mid-size to major oil and gas companies and power 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 financial position or results of operations as a result of counterparty performance.

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

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 Securities Exchange Act of 1934 ("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, 2011 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.

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Changes in Internal Control over Financial Reporting

We closed the LDH Acquisition on May 2, 2011 and are currently evaluating the internal control structure of LDH. In recording the LDH Acquisition, we followed our normal accounting procedures and internal controls. Our management also reviewed the operations of Lone Star that were included in our earnings for the three months ended September 30, 2011.

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, 2011 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, 2010 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, 2011.

ITEM 1A. RISK FACTORS

For information regarding risks, uncertainties and assumptions, see "Part I — Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2010 and "Part II — Other Information – Item 1A. Risk Factors" of our Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011. There are no material changes from risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010 and on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

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
(3)	2.1	Agreement and Plan of Merger, dated as of July 4, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(1)	2.2	Purchase Agreement, dated March 22, 2011, among ETP-Regency Midstream Holdings, LLC, LDH Energy Asset Holdings LLC and Louis Dreyfus Highbridge Energy LLC, Energy Transfer Partners, L.P. and Regency Energy Partners LP.
(4)	2.3	Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(6)	2.4	Amendment No. 1, dated as of September 14, 2011, to the Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(2)	4.1	Ninth Supplemental Indenture, dated as of May 12, 2011, to the Indenture dated January 18, 2005, by and between Energy Transfer Partners, L.P. and U.S. Bank National Association (as successor to Wachovia Bank, National Association), as trustee.
(5)	10.1	Term Loan Agreement dated as of July 28, 2011, by and among Fayetteville Express Pipeline LLC, The Royal Bank of Scotland plc, as administrative agent, and certain other agents and lenders party thereto.
(7)	10.2	Amendment No. 1, dated as of September 14, 2011, to Second Amended and Restated Agreement and Plan of Merger, dated as of July 19, 2011, by and among Energy Transfer, Equity, L.P., Sigma Acquisition Corporation and Southern Union Company
(*)	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, 2011 and December 31, 2010; (ii) our Consolidated Statements of Operations for the three and nine months ended September 30, 2011 and 2010; (iii) our Consolidated Statements of Comprehensive Income for the three and nine months ended September 30, 2011 and 2010; (iv) our Consolidated Statement of Partners' Capital for the nine months ended September 30, 2011; (v) our Consolidated Statements of Cash Flows for the nine months ended September 30, 2011 and 2010; and (vi) the notes to our Consolidated Financial Statements.

* Filed herewith.
** Furnished herewith.
(1) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K/A filed on March 25, 2011.
(2) Incorporated by reference to Exhibit 4.2 to Registrant's Form 8-K filed May 12, 2011.
(3) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 7, 2011.
(4) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on July 20, 2011.
(5) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on August 2, 2011.
(6) Incorporated by reference to Exhibit 2.1 to Registrant's Form 8-K filed on September 15, 2011.

(7) Incorporated by reference to Exhibit 10.1 to Registrant's Form 8-K filed on September 15, 2011.

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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 7, 2011

By: /s/ Martin Salinas, Jr.
Martin Salinas, Jr.
(Chief Financial Officer duly authorized to sign on behalf of the registrant)