UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Quarterly Period Ended May 31, 2007

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the Transition Period from ______ to ______

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

2838 Woodside Street

Dallas, Texas 75204

(Address of principal executive offices and 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 x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer x Accelerated filer ¨ Non accelerated filer ¨

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

At July 9, 2007, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P.	136,981,221 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 Energy Transfer Partners officials during presentations about the Partnership, include certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Statements using words such as anticipate, believe, intend, project, plan, continue estimate, forecast, may, will, or similar expressions help identify forward-looking statements. Although the Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that every objective will be reached.

Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks, difficult to predict, and beyond management s control. For additional discussion of risks, uncertainties and assumptions, see the Partnership s Annual Report on Form 10-K for the fiscal year ended August 31, 2006 filed with the Securities and Exchange Commission on November 13, 2006.

Definitions

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

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement
Dekatherm	million British thermal units. A therm factor is used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used.
Mcf	thousand cubic feet
MMBtu	million British thermal unit
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
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

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	May 31, 2007	August 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 95,610	$ 26,041
Marketable securities	3,575	2,817
Accounts receivable, net of allowance for doubtful accounts	625,339	675,545
Inventories	297,876	387,140
Deposits paid to vendors	46,579	87,806
Exchanges receivable	40,545	23,221
Price risk management assets	25,944	56,139
Prepaid expenses and other	40,002	43,095
Total current assets	1,175,470	1,301,804
PROPERTY, PLANT AND EQUIPMENT, net	5,278,109	3,313,649
GOODWILL	716,443	604,409
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	399,330	235,151
Total assets	$ 7,569,352	$ 5,455,013

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	May 31, 2007	August 31, 2006
LIABILITIES AND PARTNERS' CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 584,436	$ 603,140
Exchanges payable	48,188	24,722
Customer advances and deposits	40,554	108,836
Accrued and other current liabilities	261,697	202,296
Price risk management liabilities	1,866	36,918
Current maturities of long-term debt	39,768	40,578
Total current liabilities	976,509	1,016,490
LONG-TERM DEBT, less current maturities	3,426,608	2,589,124
DEFERRED INCOME TAXES	100,481	106,842
OTHER NON-CURRENT LIABILITIES	16,819	5,695
COMMITMENTS AND CONTINGENCIES		
	4,520,417	3,718,151
PARTNERS CAPITAL:		
General Partner	125,290	82,450
Limited Partners:		
Common Unitholders (136,979,887 and 110,726,999 units authorized, issued and outstanding at May 31, 2007 and August 31, 2006, respectively)	2,928,185	1,647,345
Class E Unitholders (8,853,832 units authorized, issued and outstanding-held by subsidiary and reported as treasury units)		
	3,053,475	1,729,795
Accumulated other comprehensive income (loss), per accompanying statements	(4,540)	7,067
Total partners capital	3,048,935	1,736,862
Total liabilities and partners capital	$ 7,569,352	$ 5,455,013

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Three Months Ended May 31, 2007	Three Months Ended May 31, 2006	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
REVENUES:				
Midstream and transportation and storage	$ 1,406,598	$ 1,211,549	$ 3,961,880	$ 5,503,385
Propane and other	308,188	208,786	1,203,831	783,386
Total revenues	1,714,786	1,420,335	5,165,711	6,286,771
COSTS AND EXPENSES:				
Cost of products sold, midstream and transportation and storage	1,095,040	1,020,692	3,117,732	4,765,113
Cost of products sold, propane and other	192,347	126,675	742,814	481,712
Operating expenses	148,903	102,969	415,093	305,336
Depreciation and amortization	47,402	28,149	126,571	84,076
Selling, general and administrative	39,786	23,732	105,989	79,986
Total costs and expenses	1,523,478	1,302,217	4,508,199	5,716,223
OPERATING INCOME	191,308	118,118	657,512	570,548
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(46,149)	(13,674)	(128,383)	(70,609)
Equity in earnings (losses) of affiliates	839	(150)	5,212	(318)
Gain (loss) on disposal of assets	(2,500)	22	(3,785)	556
Interest and other income, net	17,751	9,672	20,845	12,933
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	161,249	113,988	551,401	513,110
Income tax expense	3,560	1,981	10,456	28,406
INCOME BEFORE MINORITY INTERESTS	157,689	112,007	540,945	484,704
Minority interests	(223)	(95)	(1,333)	(2,199)
NET INCOME	157,466	111,912	539,612	482,505
GENERAL PARTNER'S INTEREST IN NET INCOME	59,962	30,109	173,830	78,287
LIMITED PARTNERS' INTEREST IN NET INCOME	$ 97,504	$ 81,803	$ 365,782	$ 404,218
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.71	$ 0.67	$ 2.67	$ 2.79
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	136,978,390	110,658,305	131,147,779	108,466,616

DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.71	$ 0.67	$ 2.66	$ 2.78
DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	137,368,358	110,921,227	131,520,530	108,718,490

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

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Dollars in thousands)

(unaudited)

	Three Months Ended May 31, 2007	Three Months Ended May 31, 2006	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
Net income	$ 157,466	$ 111,912	$ 539,612	$ 482,505
Other comprehensive income, net of tax:				
Reclassification adjustment for gains and losses on derivative instruments accounted for as cash flow hedges included in net income	(18,432)	(2,821)	(140,393)	(44,971)
Change in value of derivative instruments accounted for as cash flow hedges	(1,124)	25,126	128,034	189,769
Change in value of available-for-sale securities	(450)	929	752	1,052
Comprehensive income	$ 137,460	$ 135,146	$ 528,005	$ 628,355
Reconciliation of Accumulated Other Comprehensive Income (Loss)				
Balance, beginning of period	$ 15,466	$ 37,299	$ 7,067	$ (85,317)
Current period reclassification to earnings	(18,432)	(2,821)	(140,393)	(44,971)
Current period change in value	(1,574)	26,055	128,786	190,821
Balance, end of period	$ (4,540)	$ 60,533	$ (4,540)	$ 60,533
Components of Accumulated Other Comprehensive Income (Loss)				
Commodity related derivative hedges			$ (6,632)	$ 46,007
Interest rate derivative hedges			1,033	12,539
Available-for-sale securities			1,059	1,987
Balance, end of period			$ (4,540)	$ 60,533

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

For the Nine Months Ended May 31, 2007

(Dollars in thousands)

(unaudited)

		Limited Partners	
	General Partner	Common Unitholders	Class G Unitholders
Balance, August 31, 2006	$ 82,450	$ 1,647,345	$
Distributions to partners	(155,480)	(255,739)	(40,598)
Issuance of Class G Units to Energy Transfer Equity, LP			1,200,000
Conversion of Class G Units to Common		1,208,394	(1,208,394)
General Partner capital contribution	24,490		
Unit-based compensation expense		11,395	
Net income	173,830	316,790	48,992
Balance, May 31, 2007	$ 125,290	$ 2,928,185	$

The accompanying notes are an integral part of this condensed consolidated financial statement.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 869,273	$ 527,795
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(87,487)	(35,949)
Working capital settlement on prior year acquisitions		19,653
Capital expenditures	(799,245)	(510,572)
Advances to and investment in affiliates	(986,794)	
Proceeds from the sale of assets	20,789	4,551
Net cash used in investing activities	(1,852,737)	(522,317)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	3,269,757	1,585,057
Principal payments on debt	(2,979,809)	(1,486,700)
Net proceeds from issuance of limited partner units	1,200,000	132,383
Capital contribution from General Partner	24,490	2,702
Distributions to partners	(451,817)	(235,894)
Debt issuance costs	(9,588)	(1,295)
Net cash provided by (used in) financing activities	1,053,033	(3,747)
INCREASE IN CASH AND CASH EQUIVALENTS	69,569	1,731
CASH AND CASH EQUIVALENTS, beginning of period	26,041	24,914
CASH AND CASH EQUIVALENTS, end of period	$ 95,610	$ 26,645

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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Dollar amounts in thousands, except per unit data)

(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of August 31, 2006, which has been derived from audited financial statements, and the unaudited interim financial statements and notes thereto of Energy Transfer Partners, L.P., and subsidiaries (collectively, the Partnership) as of May 31, 2007 and for the three-month and nine-month periods ended May 31, 2007 and 2006, 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 Securities and Exchange Commission. 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.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the consolidated financial position of Energy Transfer Partners, L.P. and subsidiaries as of May 31, 2007, and the Partnership s results of operations for the three-month and nine-month periods ended May 31, 2007 and 2006, respectively, and cash flows for the nine-month periods ended May 31, 2007 and 2006. 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 fiscal year ended August 31, 2006, as filed with the Securities and Exchange Commission on November 13, 2006.

Certain prior period amounts have been reclassified to conform to the 2007 presentation. These reclassifications had no impact on net income or total partners capital.

Business Operations

In order to simplify the obligations of Energy Transfer Partners, L.P. under the laws of several jurisdictions in which we conduct business, our activities are conducted through four subsidiary operating partnerships, 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, Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, LLC (ETC MEP), both are Delaware limited liability companies engaged in interstate transportation of natural gas, Heritage Operating L.P. (HOLP), a Delaware limited partnership engaged in retail and wholesale propane operations, and Titan Energy Partners, LP (Titan), a Delaware limited partnership engaged in retail propane operations, (collectively the Operating Partnerships). The Partnership, the Operating Partnerships, and their other subsidiaries are collectively referred to in this report as we , us , ETP , Energy Transfer or the Partnership .

2. ESTIMATES AND SIGNIFICANT ACCOUNTING POLICIES:

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 disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and transportation and storage segments are estimated using volume estimates and market prices. Any difference between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the three and nine months ended May 31, 2007 and 2006 represent the actual results in all material respects.

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Some of the other more significant estimates made by management include, but are not limited to, the timing of certain forecasted transactions that are hedged, allowances for doubtful accounts, the fair value of derivative instruments, useful lives for depreciation and amortization, purchase accounting allocations and subsequent realizability of intangible assets, deferred taxes, assets and liabilities resulting from the regulated ratemaking process (as discussed below), environmental reserves, and general business insurance reserves and medical self-insurance reserves. Actual results could differ from those estimates.

Significant Accounting Policies

As a result of the acquisition of Transwestern on December 1, 2006, we have the following significant accounting policies in addition to the significant accounting policies described in our Form 10-K for the year ended August 31, 2006:

Revenue Recognition - Transwestern is subject to Federal Energy Regulatory Commission (FERC) regulations. As a result, FERC may require the refund of revenues collected during the pendency of a rate proceeding in a final order. Transwestern establishes reserves for these potential refunds, as appropriate. No such reserves were required at May 31, 2007.

Property, Plant and Equipment - An accrual of allowance for funds used during construction (AFUDC) is a utility accounting practice calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant. It represents the cost of servicing the capital invested in construction work-in-progress. AFUDC has been segregated into two component parts borrowed funds and equity funds. The allowance for borrowed and equity funds used during construction totaled $1,324 and $2,046 for the three and nine months ended May 31, 2007, respectively.

System Gas - Transwestern accounts for system balancing gas using the fixed asset accounting model established under FERC Order No. 581. Under this approach, system gas volumes are classified as fixed assets and valued at historical cost. Encroachments upon system gas are valued at current market prices. Transwestern may sell system gas in excess of its system operational requirements.

Depreciation and Amortization - The provision for depreciation and amortization is computed using the straight-line method based on estimated economic or FERC mandated lives. Transwestern s composite depreciation rates are applied to the FERC functional groups of gross property having similar economic characteristics. Transmission Plant is depreciated at 1.2 percent per year, and General Plant is depreciated at 10.0 percent per year. Intangible assets are amortized at rates ranging from 8.0 percent to 20.0 percent per year.

Employee Benefits - Transwestern has entered into a VEBA trust (the VEBA Trust) agreement with Bank One Trust Company as a trustee. The VEBA Trust has established or adopted plans to provide certain post-retirement life, sick, accident and other benefits. The VEBA Trust is a voluntary employees beneficiary association under Section 501(c)(9) of the Tax Code, which provides benefits to employees of Transwestern. Transwestern s plan is in an overfunded position as of May 31, 2007. As the plans are supported through rates charged to customers, under FASB Statement No. 71, *Accounting for Effects of Certain Types of Regulation* (SFAS 71), to the extent Transwestern has collected amounts in excess of what is required to fund the plan, Transwestern has an obligation to refund the excess amounts to customers through rates. As such, Transwestern has recorded the overfunded position of $881 within deferred assets and a corresponding regulatory liability of $881.

Transwestern accounts for its other post employment benefits (OPEB) liability and expense on an actuarial basis, recording its health and life benefit costs over the active service period of employees to the date of full eligibility for the benefits.

Regulatory Assets and Liabilities - Transwestern is subject to regulation by certain state and federal authorities, is part of our interstate transportation segment and has accounting policies that conform to SFAS 71, which is in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows us to defer expenses and revenues on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and revenues will be allowed in the ratemaking process in a period different from the period in which they would have been reflected in the consolidated statement of operations by an unregulated company. These deferred assets and liabilities will be reported in results of operations in the period in which the same amounts are included in rates and recovered from or refunded to customers. Management s assessment of the probability of recovery or pass through of regulatory assets and liabilities will require judgment and interpretation of laws and regulatory commission orders. If, for any reason, we cease to meet the criteria for application of regulatory accounting treatment for all or part of our operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the condensed consolidated balance sheet for the period in which the discontinuance of regulatory accounting treatment occurs.

New Accounting Standards

FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes An Interpretation of FASB Statement No. 109*, (FIN 48). FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with SFAS No. 109. FIN 48 also prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The new FASB standard also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. The evaluation of a tax position in accordance with FIN 48 is a two-step process. The first step is a recognition process whereby the enterprise determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the enterprise should presume that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more-likely-than-not recognition threshold is calculated to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50% likely of being realized upon ultimate settlement. The provisions of FIN 48 are effective for fiscal years beginning after December 15, 2006. Earlier application is permitted as long as the enterprise has not yet issued financial statements, including interim financial statements, in the period of adoption. The provisions of FIN 48 are to be applied to all tax positions upon initial adoption of this standard. Only tax positions that meet the more-likely-than-not recognition threshold at the effective date may be recognized or continue to be recognized upon adoption of FIN 48. The cumulative effect of applying the provisions of FIN 48 should be reported as an adjustment to the opening balance of retained earnings (or other appropriate components of equity or net assets in the statement of financial position) for that fiscal year. In February 2007 the SEC clarified that if a registrant changes how it classifies interest and penalties upon adoption of FIN 48, it should not reclassify amounts in prior periods. However, the registrant should disclose its prior classification policy. We are currently evaluating FIN 48 and have not yet determined the impact of such on our financial statements. We plan to adopt this statement on September 1, 2007.

FASB Staff Position No. EITF 00-19-2, *Accounting for Registration Payment Arrangements* (FSP 00-19-2). FSP 00-19-2, issued in December 2006, provides guidance related to the accounting for registration payment arrangements. FSP 00-19-2 specifies that the contingent obligation to make future payments or otherwise transfer consideration under a registration payment arrangement, whether issued as a separate arrangement or included as a provision of a financial instrument or arrangement, should be separately recognized and measured in accordance with FASB No. 5, *Accounting for Contingencies* (SFAS No. 5). FSP 00-19-2 requires that if the transfer of consideration under a registration payment arrangement is probable and can be reasonably estimated at inception, the contingent liability under such arrangement shall be included in the allocation of proceeds from the related financing transaction using the measurement guidance in SFAS No. 5. FSP 00-19-2 applies immediately to any registration payment arrangement entered into subsequent to the issuance of the Staff Position. We have not executed any registration rights agreements subsequent to the issuance of this FASB Staff Position. For such arrangements issued prior to the issuance of FSP-00-19-2, the guidance is effective for financial statements issued for fiscal years beginning after December 15, 2006 and interim periods within those fiscal years. We are currently evaluating FSP 00-19-2 and have not yet determined the impact of such on our financial statements related to registration rights agreements issued prior to December 2006. We plan to adopt this Staff Position beginning September 1, 2007.

SFAS No. 157, *Fair Value Measurement*, (SFAS 157). This new standard provides guidance for using fair value to measure assets and liabilities. SFAS 157 applies whenever other standards require (or permit) assets or liabilities to be measured at fair value but does not expand the use of fair value in any new circumstances.

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The standard clarifies that for items that are not actively traded, such as certain kinds of derivatives, fair value should reflect the price in a transaction with a market participant, including an adjustment for risk. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. SFAS 157 establishes a fair value hierarchy that prioritizes the information used to develop those assumptions. The fair value hierarchy gives the highest priority to quoted prices in active markets and the lowest priority to unobservable data, for example, the reporting entity s own data. Under the standard, fair value measurements would be separately disclosed by level within the fair value hierarchy. The provisions of SFAS 157 are effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. Earlier application is encouraged, provided that the reporting entity has not yet issued financial statements for that fiscal year, including any financial statements for an interim period within that fiscal year. We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our fiscal year beginning September 1, 2008.

SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of FASB Statement No. 115*, (SFAS 159). This new standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment applies to all entities with available-for-sale and trading securities. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity s first fiscal year that begins after November 15, 2007. Early adoption is permitted as of the beginning of the previous fiscal year provided that the entity makes the choice in the first 120 days of that fiscal year and also elects to apply the provisions of FASB Statement No. 157, *Fair Value Measurements* (discussed above). We are currently evaluating this statement and have not yet determined the impact of such on our financial statements. We plan to adopt this statement when required at the start of our fiscal year beginning September 1, 2008.

EITF Issue No. 06-3, *How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross Versus Net Presentation)* (EITF 06-3). This accounting guidance requires companies to disclose their policy regarding the presentation of tax receipts on the face of their income statements. The scope of this guidance includes any tax assessed by a governmental authority that is directly imposed on a revenue-producing transaction between a seller and a customer and may include, but is not limited to, sales, use, value added, and some excise taxes (gross receipts taxes are excluded). We adopted the provisions of EITF 06-3 during the quarter ended May 31, 2007, the impact of which is not material. We present the collection of taxes to be remitted to government authorities in our condensed consolidated statement of operations on a net basis.

SEC Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements* (SAB 108). In September 2006, the Securities and Exchange Commission (SEC) provided guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB 108 establishes a dual approach that requires quantification of financial statement errors based on the effects of the error on each of the company s financial statements and the related financial statement disclosures. SAB 108 is effective for fiscal years ending after November 15, 2006. We expect to adopt SAB 108 by August 31, 2007. We are presently reviewing the impact of the adoption of SAB 108. We do not expect such adoption to have a material impact on our consolidated financial statements.

3. SIGNIFICANT ACQUISITIONS:

Fiscal year 2007 acquisitions

In September 2006 we acquired two small natural gas gathering systems in east and north Texas for an aggregate purchase price of $30,589 in cash. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $25,000 to be determined eighteen months from the closing date. We will record the required adjustment to the purchase price allocation when the amount of actual contingent consideration is determinable beyond a reasonable doubt. These systems provide us with additional capacity in the Barnett Shale and in the Travis Peak area of east Texas and are included in our midstream operating segment. The cash paid for these acquisitions was financed primarily from advances under the ETP Revolving Credit Facility.

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On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (GE) and Southern Union Company (Southern Union), we acquired the member interests in CCE Holdings, LLC (CCEH) from GE and certain other investors for $1,000,000. We financed a portion of the CCEH purchase price with the proceeds from our issuance of 26,086,957 Class G Units to Energy Transfer Equity, L.P. simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH. On December 1, 2006, in a second and related transaction, CCEH redeemed ETP s 50% interest ownership in CCEH in exchange for 100% ownership of Transwestern which owns the Transwestern Pipeline, a 2,400 mile interstate natural gas pipeline. Following the final step, Transwestern became a new operating subsidiary and separate segment of ETP.

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

Basis of investment in CCEH at November 30, 2006	$ 956,348
Distributions received on December 1, 2006	(6,217)
Fair value of short term debt assumed	13,000
Fair value of long-term debt assumed	519,377
Other assumed long-term indebtedness	10,096
Current liabilities assumed	35,781
Cash acquired	(3,386)
Acquisition costs incurred	11,423
Total	$ 1,536,422

During the nine months May 31, 2007, HOLP and Titan collectively acquired substantially all of the assets of five propane businesses. The aggregate purchase price for these acquisitions totaled $16,210 which included $15,008 of cash paid, net of cash acquired, and liabilities assumed of $1,202. The cash paid for acquisitions was financed primarily with ETP s and HOLP s Senior Revolving Credit Facilities.

In December 2006 we purchased a natural gas gathering system in north Texas for $32,000. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $21,000 to be determined two years after the closing date. We will record the required adjustment to the purchase price allocation when the amount of the actual contingent consideration is determinable beyond a reasonable doubt. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas.

In January 2007 we purchased a natural gas gathering system in New Mexico for $8,000. The gathering system, which is included in our midstream segment, is approximately 27 miles long and is our first gathering system in New Mexico.

Except for the acquisition of the 50% member interests in CCEH, these acquisitions were accounted for under the purchase method of accounting in accordance with SFAS No. 141 and the purchase prices were allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition. The acquisition of the 50% member interest in CCEH was accounted for under the equity method of accounting in accordance with APB Opinion No. 18, through November 30, 2006. The acquisition of 100% of Transwestern has been accounted for under the purchase method of accounting since the acquisition on December 1, 2006. Pro forma effects of the Transwestern acquisition are discussed below. In the aggregate, the other acquisitions described above are not material for pro forma disclosure purposes.

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The following table presents the allocation of the acquisition cost to the assets acquired and liabilities assumed based on their fair values for the acquisitions described above occurring during the period ended May 31, 2007, net of cash acquired:

	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$	$ 20,062	$ 600
Inventory		895	170
Prepaid and other current assets		11,842	57
Property, plant, and equipment	47,656	1,254,968	10,280
Intangibles and other assets	23,015	141,378	3,088
Goodwill		107,277	2,015
Total assets acquired	70,671	1,536,422	16,210
Accounts payable		(1,932)	
Customer advances and deposits			(193)
Accrued and other current liabilities		(33,849)	(70)
Short-term debt (paid in December 2006)		(13,000)	
Long-term debt		(519,377)	(939)
Other long-term obligations		(10,096)	
Total liabilities assumed		(578,254)	(1,202)
Net assets acquired	$ 70,671	$ 958,168	$ 15,008

The purchase price for the acquisitions has been initially allocated based on the estimated fair value of the assets acquired and liabilities assumed. The Transwestern allocation was based on the preliminary results of independent appraisals. The purchase price allocations have not been completed and are subject to change. We expect to complete the allocations during the first quarter of fiscal year 2008.

Included in the additions for interstate property, plant and equipment is an aggregate plant acquisition adjustment of $446,154, which represents costs allocated to Transwestern s transmission plant. This amount has not been included in the determination of tariff rates Transwestern charges to its regulated customers. The unamortized balance of this adjustment was $439,781 at May 31, 2007 and is being amortized over 35 years, the composite weighted average estimated remaining life of Transwestern s assets as of the acquisition date.

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

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

At May 31, 2007, all of Transwestern s regulatory assets are recoverable in rates.

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

	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Intangible assets:			
Contract rights (6 to 15 years)	$ 23,015	$ 47,582	$
Financing costs (7 to 9 years)		13,410	
Other			3,088
Total intangible assets	23,015	60,992	3,088
Goodwill		107,277	2,015
Total intangible assets and goodwill acquired	$ 23,015	$ 168,269	$ 5,103

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

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of the Midcontinent Express Pipeline (MEP). The approximately 500-mile interstate natural gas pipeline, which will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco in Butler, Alabama, will have an initial capacity of 1.4 Bcf per day. Pending necessary regulatory approvals, the approximately $1,250,000 pipeline project is expected to be in service by February 2009. MEP has prearranged binding commitments from multiple shippers for 800,000 dekatherms per day which includes a binding commitment from Chesapeake Energy Marketing, Inc., an affiliate of Chesapeake Energy Corporation, for 500,000 dekatherms per day. MEP has executed a firm capacity lease agreement for approximately 280,000 dekatherms per day of capacity on the Oklahoma intrastate pipeline system of Enogex, a subsidiary of OGE Energy, to provide transportation capacity from various locations in Oklahoma into and through MEP. The new pipeline will also interconnect with Natural Gas Pipeline Company of America, a wholly-owned subsidiary of Kinder Morgan, Inc., and with our Texoma pipeline near Paris, Texas. The MEP joint venture is accounted for using the equity method of accounting prescribed by APB Opinion No. 18.

Fiscal year 2006 acquisitions

On June 1, 2006, we acquired all the propane operations of Titan for cash of approximately $548,000, after working capital adjustments and net of cash acquired, and liabilities assumed of approximately $46,000. We accounted for the Titan acquisition as a business combination using the purchase method of accounting in accordance with the provisions of SFAS 141. The purchase price was initially allocated based on the estimated fair value of the individual assets acquired and the liabilities assumed at the date of the acquisition based on the results of an independent appraisal. We completed the Titan purchase allocation during our third quarter of fiscal year 2007 and the adjustments to the purchase price allocation during fiscal year 2007 were not material. The Titan operations have been included since the date of acquisition, thus the condensed consolidated results of operations for the three and nine months ended May 31, 2007 include the Titan results of operations for the entire period. However, the three and nine months ended May 31, 2006 do not include any of the Titan results of operations.

Pro Forma Results of Operations

The following unaudited pro forma consolidated results of operations for the nine months ended May 31, 2007 and the three and nine months ended May 31, 2006 are presented as if the Transwestern acquisition had been made on September 1, 2005. The operations of Transwestern have been included in our statements of operations since acquisition on December 1, 2006. Thus, pro forma information for the three months ended May 31, 2007 is not required.

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	Nine Months Ended May 31, 2007	Three Months Ended May 31, 2006	Nine Months Ended May 31, 2006
Revenues	$ 5,224,603	$ 1,476,342	$ 6,458,126
Net income	$ 556,518	$ 121,101	$ 514,677
Limited Partners' interest in net income	$ 382,349	$ 86,568	$ 425,250
Basic earnings per Limited Partner Unit	$ 2.61	$ 0.64	$ 2.62
Diluted earnings per Limited Partner Unit	$ 2.61	$ 0.64	$ 2.61

The pro forma consolidated results of operations include adjustments to give effect to depreciation of the amounts allocated to depreciable and amortizable assets, interest expense on acquisition debt, and certain other adjustments. 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.

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

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

We place our cash deposits and temporary cash investments with high credit quality financial institutions. At times, such balances may be in excess of the Federal Deposit Insurance Corporation (FDIC) insurance limit.

Net cash flows provided by operating activities is comprised as follows:

	Nine Months Ended May 31, 2007	2006
Net income	$ 539,612	$ 482,505
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	126,571	84,076
Amortization of finance costs charged to interest	2,785	2,069
Provision for loss on accounts receivable	1,751	1,073
Non-cash compensation on unit grants and other	11,395	5,375
Deferred income taxes	(2,811)	595
(Gain) loss on disposal of assets	3,785	(556)
Undistributed (earnings) losses of equity affiliates, net	(5,212)	318
Minority interests	1,333	(2,199)
Changes in operating assets and liabilities:		
Accounts receivable	68,651	350,414
Accounts receivable from related companies	(2,406)	2,266
Inventories	90,328	(153,172)
Deposits paid to vendors	41,227	(20,142)
Exchanges receivable	(11,060)	6,946
Prepaid expenses and other	16,893	(14,856)
Intangibles and other long-term assets	(4,675)	(10,720)
Regulatory assets	933	
Accounts payable	32,111	(305,538)
Accounts payable to related companies	14,050	(1,121)
Customer advances and deposits	(69,265)	(105,856)
Exchanges payable	16,935	6,290
Accrued and other current liabilities	11,695	58,902
Other long-term liabilities	2,246	(5,549)
Income taxes payable	(1,039)	(882)
Price risk management liabilities, net	(16,560)	147,557

Net cash provided by operating activities	$ 869,273	$ 527,795

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Supplemental cash flow information is as follows:

	Nine Months Ended May 31, 2007		Nine Months Ended May 31, 2006	
NONCASH FINANCING ACTIVITIES:				
Issuance of Common Units in connection with certain acquisition	$		$	4,000
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$	533,255	$	2,361
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid during the period for interest, net of $16,164 and $6,135 capitalized for May 31, 2007 and 2006, respectively	$	118,703	$	65,928
Cash paid during the period for income taxes	$	6,501	$	28,133
Transfer of investment in affiliate in purchase of Transwestern (Note 3)	$	956,348	$	

5. ACCOUNTS RECEIVABLE:

Our intrastate midstream and transportation and storage operations deal with counterparties that are typically either investment grade or are otherwise secured with a letter of credit or other forms of security (corporate guaranty, prepayment, or master set off agreement). Management reviews midstream and transportation and storage accounts receivable balances bi-weekly. Credit limits are assigned and monitored for all counterparties of the midstream and transportation and storage operations. Management believes that the occurrence of bad debts in our intrastate midstream and transportation and storage segments was not significant for the three or nine months ended May 31, 2007; therefore, an allowance for doubtful accounts for the midstream and transportation and storage segments was not deemed necessary. Bad debt expense related to these receivables is recognized at the time an account is deemed uncollectible. There was no bad debt expense recognized for the three or nine months ended May 31, 2007 and 2006 in the midstream and intrastate transportation and storage segments.

Transwestern has a concentration of customers in the electric and gas utility industries. This concentration of customers may impact Transwestern s overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments or other forms of collateral to Transwestern. Transwestern sought additional assurances from customers due to credit concerns, and held aggregate prepayments of $598 at May 31, 2007, which are recorded in customer advances and deposits in the condensed consolidated balance sheets. Transwestern s management believes that the portfolio of receivables, which includes regulated electric utilities, regulated local distribution companies and municipalities, is subject to minimal credit risk. Transwestern establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. Transwestern considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectibility. There was no bad debt expense recognized for the three months and nine months ended May 31, 2007 related to Transwestern.

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

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

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Accounts receivable consisted of the following:

	May 31, 2007	August 31, 2006
Accounts receivable - midstream and transportation and storage	$ 521,084	$ 570,569
Accounts receivable - propane	108,384	108,976
Less allowance for doubtful accounts	(4,129)	(4,000)
Total, net	$ 625,339	$ 675,545

The activity in the allowance for doubtful accounts for the retail and wholesale propane segments consisted of the following for the nine months ended May 31, 2007:

	May 31, 2007
Balance, beginning of period	$ 4,000
Provision for loss on accounts receivable	1,751
Accounts receivable written off, net of recoveries	(1,622)
Balance, end of period	$ 4,129

6. INVENTORIES:

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

Inventories consisted of the following:

	May 31, 2007	August 31, 2006
Natural gas, propane and other NGLs	$ 281,298	$ 371,430
Appliances, parts and fittings and other	16,578	15,710
Total inventories	$ 297,876	$ 387,140

7. PROPERTY, PLANT AND EQUIPMENT:

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

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

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

	May 31, 2007	August 31, 2006
Land and improvements	$ 61,417	$ 63,220
Buildings and improvements (10 to 30 years)	105,927	66,739
Pipelines and equipment (10 to 65 years)	3,090,494	1,757,103
Natural gas storage (40 years)	91,282	91,177
Bulk storage, equipment and facilities (3 to 30 years)	462,210	108,834
Tanks and other equipment (5 to 30 years)	507,470	472,944
Vehicles (5 to 10 years)	151,443	120,710
Right-of-way (20 to 65 years)	206,675	104,650
Furniture and fixtures (3 to 10 years)	21,691	16,283
Linepack	39,189	24,821
Pad Gas	55,482	57,327
Other (5 to 10 years)	83,772	27,395
	4,877,052	2,911,203
Less Accumulated depreciation	(356,955)	(242,137)
	4,520,097	2,669,066
Plus Construction work-in-process	758,012	644,583
Property, plant and equipment, net	$ 5,278,109	$ 3,313,649

Capitalized interest is included for pipeline construction projects. Interest is capitalized based on the borrowing rate of our revolving credit facility when the related costs are incurred. A total of $16,164 of interest was capitalized for pipeline construction projects during the nine months ended May 31, 2007 (excluding AFUDC, see Note 2).

Depreciation expense for the periods is as follows:

Three Months Ended May 31,		Nine Months Ended May 31,	
2007	2006	2007	2006
$ 43,095	$ 25,784	$ 115,239	$ 76,989

8. GOODWILL:

Goodwill is associated with acquisitions made for our midstream, intrastate transportation and storage, interstate transportation and retail propane segments. Goodwill is tested for impairment annually at August 31, in accordance with Statement of Accounting Standards No. 142, *Goodwill and Other Intangible Assets,* (SFAS 142). The changes in the carrying amount of goodwill for the nine month period ended May 31, 2007 were as follows:

	Midstream	Intrastate Transportation and Storage	Interstate Transportation	Retail Propane	Total
Balance, beginning of period	$ 13,409	$ 10,327	$	$ 580,673	$ 604,409
Purchase accounting adjustments				4,484	4,484

Goodwill acquired			107,277	2,015	109,292
Sale of operations				(1,742)	(1,742)
Balance, end of period	$ 13,409	$ 10,327	$ 107,277	$ 585,430	$ 716,443

The purchase price allocations for the Transwestern and other fiscal 2007 acquisitions (see Note 3) are preliminary. The final assessment of value and allocations for the fiscal 2007 acquisitions are expected to be completed by the first quarter of fiscal year 2008, and amounts allocated to goodwill may change.

9. INTANGIBLES AND OTHER ASSETS:

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

	May 31, 2007		August 31, 2006	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 32,191	$ (16,454)	$ 31,593	$ (13,012)
Customer lists (3 to 15 years)	129,872	(19,355)	87,480	(11,640)
Contract rights (6 to 15 years)	23,015	(744)		
Financing costs (3 to 15 years)	40,438	(7,604)	20,128	(4,441)
Consulting agreements (2 to 7 years)			132	(122)
Other (10 years)	2,610	(940)	2,677	(422)
Total amortizable intangible assets	228,126	(45,097)	142,010	(29,637)
Non-amortizable assets - Trademarks	65,921		64,842	
Total intangible assets	294,047	(45,097)	206,852	(29,637)
Other long-term assets:				
Regulatory assets	69,957			
Investment in and advances to affiliates	49,395		41,344	
Long-term price risk management assets	444		2,192	
Other	30,584		14,400	
Total intangibles and other long-term assets	$ 444,427	$ (45,097)	$ 264,788	$ (29,637)

The Partnership previously owned a 50% ownership interest in MidTexas Pipeline Company (MidTexas), a Texas general partnership, which owns approximately 139 miles of transportation pipeline that connects various receipt points in south Texas to delivery points at the Katy hub. Effective February 28, 2007 MidTexas was dissolved and each partner was assigned its 50% undivided interest in the pipeline (a non-cash transaction). As a result of the dissolution and now owning an undivided interest, we control the marketing and bear the risk of ownership. As a result, we ceased the use of equity accounting at February 28, 2007 and began applying proportionate consolidation prospectively for our interest in the MidTexas pipeline.

Intangibles and other assets include our 50% interest in Midcontinent Express Pipeline (MEP), a joint venture with Kinder Morgan Energy Partners, L.P. ($28,571 at May 31, 2007). As of May 31, 2007 the activity in MEP was not material to our consolidated results of operations.

Aggregate amortization expense of intangible assets is as follows:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Reported in depreciation and amortization	$ 4,307	$ 2,365	$ 11,332	$ 7,087
Reported in interest expense	$ 1,232	$ 700	$ 3,238	$ 2,069

The estimated aggregate amortization expense for the next five fiscal years is $10,679 for the remainder of fiscal 2007; $24,237 for 2008; $23,171 for 2009; $21,176 for 2010, and $18,447 for 2011.

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 in accordance with Statement of Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (SFAS 144). If such a review should indicate that the carrying amount of amortizable intangible assets is not recoverable, we reduce

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the carrying amount of such assets to fair value. We review non-amortizable intangible assets for impairment annually at August 31, or more frequently if circumstances dictate, in accordance with SFAS 144. No impairment of intangible assets was required for the three and nine month periods ended May 31, 2007 and 2006.

10. ACCRUED AND OTHER CURRENT LIABILITIES:

Accrued and other current liabilities consist of the following:

	May 31, 2007	August 31, 2006
Capital expenditures	$ 45,378	$ 38,002
Employee wages and benefits	48,990	40,236
Operating expenses	14,245	16,839
Interest payable	41,328	13,956
Other accrued expenses	111,756	93,263
Total accrued and other current liabilities	$ 261,697	$ 202,296

11. INCOME TAXES:

As a limited partnership, we are generally not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the three and nine month periods ended May 31, 2007 and 2006, our non-qualifying income did not, or was not expected to, exceed the statutory limit.

Those subsidiaries which are taxable corporations follow the asset and liability method of accounting for income taxes in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes* (SFAS 109). Under SFAS 109, deferred income taxes are recorded based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

A consolidated subsidiary acquired in the Titan acquisition has net operating loss carry forwards of approximately $13,000, which carry forwards expire at varying times through December 31, 2026. We established a deferred tax asset of approximately $4,000 in the Titan purchase price allocation for loss carry forwards as of the date of acquisition.

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the three and nine months ended May 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $2,840 and $4,694, respectively. There was no comparable state tax expense for the periods ended May 31, 2006.

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The components of our federal and state income tax provision are summarized as follows:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Current provision (benefit):				
Federal	$ 492	$ (2,111)	$ 6,979	$ 26,006
State	3,462	479	6,288	1,767
	3,954	(1,632)	13,267	27,773
Deferred provision (benefit):				
Federal	(394)	3,603	(2,572)	978
State		10	(239)	(345)
	(394)	3,613	(2,811)	633
Total	$ 3,560	$ 1,981	$ 10,456	$ 28,406

The difference between the statutory rate and the effective rate is summarized as follows:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Federal statutory tax rate	35.0%	35.0%	35.0%	35.0%
State income tax rate net of federal benefit	2.1%	2.9%	1.1%	3.1%
Earnings not subject to tax at the Partnership level	(34.9%)	(36.2%)	(34.2%)	(32.6%)
Effective tax rate	2.2%	1.7%	1.9%	5.5%

12. INCOME PER LIMITED PARTNER UNIT:

Our net income for partners capital and income statement 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 pursuant to the Partnership Agreement, which are declared and paid following the close of each quarter. Basic net income per limited partner unit, however, is computed in accordance with EITF Issue No. 03-6, *Participating Securities and the Two-Class Method Under FASB Statement No. 128* (EITF 03-6), by dividing limited partners interest in net income by the weighted average number of limited partner units outstanding (excluding treasury units). In periods when our aggregate net income exceeds the aggregate distributions, EITF 03-6 requires us to present earnings per unit as if all of the earnings for the periods were distributed (see table below) and requires a separate computation for each quarter and year-to-date. For such periods, an increased amount of net income is allocated to the General Partner for the additional pro forma priority income attributable to the application of EITF 03-6. The General Partner is entitled to receive incentive distributions if the amount we distribute to our limited partners with respect to any quarter exceeds levels specified in the Partnership Agreement. Diluted net income per limited partner unit is computed by dividing net income available to limited partners, after considering the General Partner s interest, by the weighted average number of limited partner units outstanding and of the effect of non-vested restricted units (Unit Grants) granted under the Amended and Restated 2004 Unit Plan and predecessor plan computed using the treasury stock method.

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

	Three Months Ended May 31, 2007	Three Months Ended May 31, 2006	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
Net income	$ 157,466	$ 111,912	$ 539,612	$ 482,505
Adjustments:				
General Partner s equity ownership	(3,149)	(2,094)	(10,792)	(9,506)
General Partner s incentive distributions	(56,813)	(28,015)	(163,038)	(68,781)
Limited Partner s interest in net income for statement of operations reporting	97,504	81,803	365,782	404,218
Less earnings allocated to Class C Units as a result of the SCANA settlement		(3,599)		(3,599)
Additional earnings allocation to General Partner		(3,894)	(16,068)	(98,100)
Net income available to limited partners for income per unit computations	$ 97,504	$ 74,310	$ 349,714	$ 302,519
Weighted average limited partner units basic	136,978,390	110,658,305	131,147,779	108,466,616
Basic net income per limited partner unit	$ 0.71	$ 0.67	$ 2.67	$ 2.79
Weighted average limited partner units	136,978,390	110,658,305	131,147,779	108,466,616
Dilutive effect of Unit Grants	389,968	262,922	372,751	251,874
Weighted average limited partner units, assuming dilutive effect of Unit Grants	137,368,358	110,921,227	131,520,530	108,718,490
Diluted net income per limited partner unit	$ 0.71	$ 0.67	$ 2.66	$ 2.78

13. <u>DEBT OBLIGATIONS</u>:

On October 23, 2006, ETP issued a total of $800,000 aggregate principal amount of Senior Notes comprised of $400,000 of 6.125% Senior Notes due 2017 (the 2017 Notes) and $400,000 of 6.625% Senior Notes due 2036 (the 2036 Notes and together with the 2017 Notes, the Notes). The Partnership used the proceeds of approximately $791,000 (net of bond discounts of $2,612 and financing costs of $6,050) from the issuance of the Notes to repay borrowings and accrued interest outstanding under the ETP Revolving Credit Facility, to pay expenses associated with the offering and for general partnership purposes. Interest on the notes is due semiannually. The Partnership may redeem some or all of the Notes at any time, or from time to time, pursuant to the terms of the indenture. All of the Partnership s obligations under the Notes are fully and unconditionally guaranteed by ETC OLP and Titan and substantially all of their present and future wholly-owned subsidiaries. These notes have been registered under the Securities Act pursuant to our S-3 Registration Statement which provides for the sale of a combination of units and debt totaling $1,500,000.

We have a $1,500,000 Amended and Restated Revolving Credit Facility (the ETP Revolving Credit Facility) available through June 29, 2011. Amounts borrowed under the ETP Revolving Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. There is also a Swingline loan option with a maximum borrowing of $75,000 at a daily rate based on LIBOR. The commitment fee payable on the unused portion of the facility varies based on our credit rating with a maximum fee of 0.175%. As of May 31, 2007, there was a balance of $735,112 in revolving credit loans (including $68,112 in Swingline loans) and $57,256 in letters of credit. The weighted average interest rate on the total amount outstanding at May 31, 2007, was 5.994%. The total amount available under the ETP Revolving Credit Facility as of May 31, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $707,632. The ETP Revolving Credit Facility is fully and unconditionally guaranteed by ETC OLP and Titan and all of their direct and indirect wholly-owned subsidiaries. The ETP Revolving Credit Facility is unsecured and has equal rights to holders of our other current and future unsecured debt.

Long-term debt (net of current portion) we assumed in connection with the Transwestern acquisition on December 1, 2006 was as follows:

5.39% Notes due November 17, 2014	$ 270,000
5.54% Notes due November 17, 2016	250,000
Total long-term debt outstanding	520,000
Unamortized debt discount	(623)
Total long-term debt assumed	$ 519,377

No principal payments are required under any of the debt agreements prior to their respective maturity dates. However, in connection with our acquisition of Transwestern, due to a change in control provision in Transwestern s debt agreements, Transwestern was required to pre-pay approximately $307,000 of long-term debt, of which $292,000 was paid in February 2007 and $15,000 was paid in March 2007. These payments were financed with borrowings under ETP s Revolving Credit Facility.

In May 2007, Transwestern issued a total of $307,000 aggregate principal amount of Senior Unsecured Series Notes (Unsecured Series Notes) comprised of the following:

Principal	Interest Rate	Maturity Date
$ 82,000	5.64%	May 24, 2017
150,000	5.89%	May 24, 2022
75,000	6.16%	May 24, 2037

The Partnership used $295,000 of the proceeds received to repay borrowings and accrued interest outstanding under the ETP Revolving Credit Facility and $12,000 for general partnership purposes. Interest is payable semi-annually, and the Unsecured Series Notes rank pari passu with Transwestern s other unsecured debt. The Unsecured Series Notes are prepayable at any time in whole or pro rata in part, subject to a premium or upon a change of control event, as defined.

Transwestern s credit agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and require certain debt to capitalization ratios.

A $75,000 Senior Revolving Facility (the HOLP Facility) is available to HOLP through June 30, 2011. The HOLP Facility has a swingline loan option with a maximum borrowing of $10,000 at a prime rate. Amounts borrowed under the HOLP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the HOLP Facility credit agreement, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility. As of May 31, 2007, there was no balance outstanding on the revolving credit loans. A Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Facility. There were outstanding Letters of Credit of $1,002 at May 31, 2007. The sum of the loans made under the HOLP Facility plus the Letter of Credit Exposure and the aggregate amount of all swingline loans cannot exceed the $75,000 maximum amount of the HOLP Facility. The amount available at May 31, 2007 was $73,998.

We were in compliance with all of the covenants of our debt agreements at May 31, 2007 and August 31, 2006.

14. PARTNERS CAPITAL AND UNIT-BASED COMPENSATION PLANS:

Limited Partner Units

Limited Partner interests are represented by Common, Class E and (prior to May 1, 2007) Class G Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of May 31, 2007, we had limited partner interests represented by

136,979,887 Common Units issued and outstanding, an aggregate 98% Limited Partner interest. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

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Common Units

The change in Common Units during the nine month period ended May 31, 2007 is as follows:

Balance, beginning of period	110,726,999
Conversion of Class G Units to Common Units	26,086,957
Issuance of restricted Common Units under our unit-based compensation plans	165,931
Balance, end of period	136,979,887

Of the total restricted Common Units issued during the period, 156,573 were employee awards under our 2004 Unit Plan (discussed below), 7,025 were Director Awards under our 2004 Unit Plan, and 2,333 were Director Awards under our Restricted Unit Plan which vested on September 1, 2006. As of May 31, 2007, there are 1,333 unvested awards remaining under the Restricted Unit Plan (which plan was terminated in June 2004). No additional grants have been, or will be, made under the Restricted Unit Plan.

Class G Units

The change in Class G Units during the nine month period ended May 31, 2007 is as follows:

Balance, beginning of period	
Issuance of Class G Units to Energy Transfer Equity, LP	26,086,957
Conversion of Class G Units to Common Units	(26,086,957)
Balance, end of period	

On November 1, 2006, we issued 26,086,957 Class G Units to Energy Transfer Equity, LP (ETE) for aggregate proceeds of $1,200,000 in order to fund a portion of the Transwestern Acquisition and to repay indebtedness we incurred in connection with the Titan acquisition. The Class G Units, a newly created class of our limited partner interests, were issued to ETE at a price of $46.00 per unit, based upon a market discount from the closing price of our Common Units on October 31, 2006 of $48.94. The terms of the Class G Units provided that they may be converted to Common Units on a one-for-one basis upon approval of a majority of the votes cast by the holders of our Common Units provided that the total votes cast by such holders represent a majority of the Common Units entitled to vote. The Class G Units were issued to ETE pursuant to a customary agreement, and registration rights have been granted to ETE. On May 1, 2007, at a special meeting of the Common Unitholders, the unitholders approved the conversion of Class G Units to Common Units and all of the outstanding Class G Units converted to Common Units on a one-for-one basis on May 1, 2007.

Quarterly Distributions of Available Cash

On October 16, 2006, we paid a quarterly distribution related to the fourth quarter of our fiscal year 2006 of $0.75 per Common Unit, or $3.00 per unit annually, to Unitholders of record at the close of business on October 5, 2006.

On January 15, 2007, we paid a quarterly distribution related to the first quarter of our fiscal year 2007 of $0.7688 per Limited Partner Unit, or $3.075 per Limited Partner Unit annually, to Unitholders of record at the close of business on January 4, 2007.

On April 13, 2007, we paid a quarterly distribution related to the second quarter of our fiscal year 2007 of $0.7875, or $3.15 per Limited Partner Unit annually to Unitholders of record at the close of business on April 6, 2007.

On June 20, 2007, we declared a per unit cash distribution of $0.80625, or $3.225 per Limited Partner Unit annually (a $0.01875 increase from the previous quarterly distribution per Limited Partner Unit) for the quarter ended May 31, 2007, which will be paid on July 16, 2007 to Unitholders of record at the close of business on July 2, 2007.

On October 16, 2006, we paid a quarterly distribution of $42,609 in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. On January 15, 2007, we paid a

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quarterly distribution of $55,151 in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. On April 13, 2007 we paid a quarterly distribution of $57,720 in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. On July 16, 2007, we will pay a quarterly distribution of $60,290 in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. Our General Partner s incentive distributions rights entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis). These incentive distributions entitle our General Partner to increasing percentages of our cash distributions based upon exceeding incentive distribution thresholds specified in our Partnership Agreement, which incentive distribution rights entitle our General Partner to receive 50% of our cash distributions in excess of $0.4125 per unit. At current distribution levels, our General Partner is entitled to receive cash distributions at the highest incentive distribution level of 50% with respect to our distributions in excess of $0.4125 per unit.

The total amount of distributions declared (all from Available Cash from Operating Surplus) related to the nine months ended May 31, 2007 was as follows:

Limited Partners - Common Units	$ 283,014
Class E Units	9,363
Class G Units	40,598
General Partners - 2% Ownership	10,123
Incentive Distribution Rights	163,038
	$ 506,136

Unit Based Compensation Plans

We follow the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004) *Accounting for Stock-based Compensation* (SFAS 123R) for our unit-based compensation plans. Adoption of SFAS 123R during fiscal 2006 did not have a material effect on our net income. As provided in SFAS 123R, the Partnership values the unit awards based on the per unit grant-date market value reduced by the present value of the distributions expected to be paid on the units during the requisite service period to which the award recipients are not entitled. The present value of expected service period distributions is computed based on the risk-free interest rate, the expected life of the unit grants and the expected unit distributions.

We recognized compensation expense of $5,324 for the three months ended May 31, 2007. Unit based compensation expense for the three months ended May 31, 2006 was not significant. For the nine months ended May 31, 2007 and 2006 we recognized compensation expense related to unit-based compensation plans of $11,395 and $5,375, respectively, as discussed below.

2004 Unit Plan

Our Amended and Restated 2004 Unit Award Plan (the 2004 Unit Plan) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers, and directors. As of May 31, 2007, 1,022,707 ETP Common Units were available for future grants under the 2004 Unit Plan.

Employee Grants

The Compensation Committee, in its discretion, may from time to time grant awards to any employee, upon such terms and conditions as it may determine appropriate and in accordance with general guidelines as defined by the 2004 Unit Plan. All outstanding awards shall fully vest into units upon any Change in Control, as defined by the 2004 Unit Plan, or upon such terms as the Compensation Committee may require at the time the award is granted.

To date, all of the awards granted to employees under the 2004 Unit Plan require the achievement of performance objectives in order for the awards to become vested. The expected life of each grant is assumed to be the minimum vesting period under the performance objectives of each grant. Generally, each award has been structured to provide that, if the performance objectives related to such award are achieved, one third of the units subject to such award will vest each year over a three-year period. The performance criteria are generally based upon the total return (unit price appreciation plus cash distributions) to our Unitholders as

compared to a group of publicly traded partnership peer companies. Management deems it probable that all units will vest; thus, compensation expense was recorded. The issuance of Common Units pursuant to the 2004 Unit Plan is intended to serve as a means of incentive compensation, therefore, no consideration will be payable by the plan participants upon vesting and issuance of the Common Units.

We assumed a weighted average risk-free interest rate of 4.42% for the three and nine months ended May 31, 2007 in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each employee grant. For the employee awards outstanding as of the period ended May 31, 2007, the grant-date average per unit cash distributions were estimated to be $5.15. Upon vesting, ETP Common Units are issued.

The following table shows the activity of the employee grants during the nine months ended May 31, 2007:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of August 31, 2006	357,750	$ 24.96
Awards granted	399,500	43.36
Awards vested	(156,573)	24.15
Awards forfeited	(68,140)	33.57
Unvested awards as of May 31, 2007	532,537	$ 38.05

The total expected compensation expense to be recognized related to the unvested employee awards as of May 31, 2007 is $5,191 for the remainder of fiscal year 2007, $11,513 for fiscal year 2008, $5,525 for fiscal year 2009, $2,298 for fiscal year 2010, $1,188 for fiscal year 2011, and $328 for fiscal year 2012.

Director Grants

Each director who is not also (i) a shareholder or a direct or indirect employee of any parent, or (ii) a direct or indirect employee of ETP LLC, the Partnership, or a subsidiary (Director Participant), who is elected or appointed to the Board for the first time shall automatically receive, on the date of his or her election or appointment, an award of up to 2,000 ETP Common Units (the Initial Director s Grant). Each September 1 that this Plan is in effect, each Director Participant who is in office on such September 1, shall automatically receive an award of Units equal to $25 ($15 prior to October 17, 2006) divided by the fair market value of a Common Unit on such date rounded to the nearest increment of ten Units (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of one third per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a Change in Control, as defined by the Plan, unless voluntarily waived by such Director Participant, and (ii) all awards which have not yet vested on the date a Director Participant ceases to be a director shall vest on such terms as may be determined by the Compensation Committee.

We assumed a weighted average risk-free interest rate of 3.80% for the three and nine months ended May 31, 2007 in estimating the present value of the future cash flows of the distributions during the vesting period on the measurement date of each Director Grant. For the Director Awards granted during the three and nine months ended May 31, 2007, the grant-date average per unit cash distributions were estimated to be $4.95.

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The following table shows the activity of the Director Grants during the nine months ended May 31, 2007:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of August 31, 2006	15,951	$ 22.54
Awards vested	(7,025)	22.45
Awards granted	3,240	41.47
Unvested awards as of May 31, 2007	12,166	$ 27.63

The total expected compensation expense to be recognized related to the unvested Director Awards as of May 31, 2007 is $44 for the remainder of fiscal year 2007, $60 for fiscal year 2008, and $14 for fiscal year 2009.

On October 17, 2006, the Compensation Committee recommended, following its receipt and review of an independent third-party compensation study, and the Board of Directors approved, an amendment to the 2004 Unit Plan to provide that Annual Director s Grants shall be equal to $25 divided by the fair market value of Common Units on that date. All other Annual Director s Grants shall be measured at September 1 of each year.

Long-Term Incentive Grants

The Compensation Committee may, from time to time, grant awards under the Plan to any executive officer or any employee it designates as a participant in accordance with general guidelines under the Plan. As of May 31, 2007, there have been no long-term incentive grants made under the Plan.

Related Party Awards

Through May 31, 2007, a partnership, the general partner of which is owned and controlled by the President of our General Partner, awarded new officers of ETP certain rights related to units of ETE previously issued by ETE to such officer. These rights include the economic benefits of ownership of these units based on a 5-year vesting schedule whereby the employee will vest in the units at a rate of 20% per year. None of the costs related to such awards are paid by ETP or ETE. Based on GAAP covering related party transactions and unit-based compensation arrangements, we are recognizing non-cash compensation expense over the vesting period based on the grant date per unit market value of the ETE units awarded the ETP employees assuming no forfeitures. Awards granted for the nine months ended May 31, 2007 result in a total non-cash compensation expense of approximately $19,258 to be recognized over the related vesting period. For the three and nine month periods ended May 31, 2007, we recognized non-cash compensation expense of $2,256 and $2,610, respectively, as a result of these awards. As these units were outstanding prior to these awards, the awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE. We expect to recognize non-cash compensation expense as follows in future periods related to these awards:

Remainder of fiscal 2007	$ 2,256
Fiscal 2008	6,699
Fiscal 2009	3,878
Fiscal 2010	2,298
Fiscal 2011	1,188
Fiscal 2012	329

15. <u>REGULATORY MATTERS, COMMITMENTS, CONTINGENCIES, AND ENVIRONMENTAL LIABILITIES</u>:

Regulatory Matters

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. On March 9, 2007, Transwestern filed with the FERC its Stipulation and Agreement of Settlement (Stipulation and Agreement) which provides for (i) revised base tariff rates, (ii) the amortization of certain costs, including the Enron Cash Balance Plan, regulatory commission expense, post retirement benefits, the accumulated reserve adjustment regulatory asset, deferred income taxes, and certain non-PCB environmental costs, and (iii) a depreciation rate of 1.20 percent for all transmission plant facilities. On April 27, 2007, FERC approved the Stipulation and Agreement with an effective date of April 1, 2007. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. In addition, on June 26, 2007, the FERC approved the uncontested February 1, 2007 filed settlement, which settlement fully resolves all the issues set for technical conference by the October 31, 2006 Order, except for the gas quality specifications for Wobbe and Btu.

The Phoenix Expansion project, as filed with FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. Total project costs are estimated to be approximately $710,000 with a projected in-service date in the third or fourth calendar quarter of 2008, subject to FERC approval. On April 27, 2007 the FERC issued the draft environmental impact statement to Transwestern. Transwestern has incurred expenditures of $62,312 through May 31, 2007 for the Phoenix Expansion project.

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of MEP. MEP, an approximately 500-mile interstate natural gas pipeline which will originate near Bennington, Oklahoma and terminate at an interconnect with Transco in Butler, Alabama, is currently pending necessary regulatory approvals. On February 14, 2007, MEP initiated public review of the project pursuant to FERC s NEPA pre-filing review process. MEP anticipates filing its application with FERC for a Natural Gas Act Section 7 Certificate of Public Convenience and Necessity by August 27, 2007. The Section 7 Certificate must be granted before construction may commence. The approximately $1,250,000 pipeline project is expected to be in service by February 2009.

Commitments

As a result of the Transwestern acquisition, we have additional non-cancelable operating leases for property and equipment which require annual rental payments of approximately $3,400 through year 2009 and $300 through year 2020. Transwestern is currently negotiating an extension of the operating lease expiring in 2009.

Total rental expense under our operating leases was approximately $9,366 and $21,555 for the three and nine months ended May 31, 2007, respectively, and has been included in operating expenses in the condensed consolidated statements of operations.

In the normal course of our business, we purchase, process and sell natural gas pursuant to long-term contracts and enter into long-term transportation and storage agreements. Such contracts contain terms that are customary in the industry. We believe that such terms are commercially reasonable and will not have a material adverse effect on our financial position or results of operations.

Titan has a long-term purchase contract with Enterprise Products Operating, L.P. (an affiliate of Enterprise GP Holdings, L.P. who owns a 34.9% non-controlling equity interest in LE GP, L.L.C., ETE s General Partner, see Note 17) to purchase substantially all of Titan s propane requirements. The contract continues until March 31, 2010 and contains renewal and extension options. The contract contains various service level agreements between the parties.

On October 3, 2006, we entered into long-term agreements with CenterPoint Energy Resources Corp. (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region commencing on April 1, 2007. These agreements replace a previous agreement with CenterPoint. Under the terms of the new agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel Storage facility. Under the new agreements with CenterPoint, we will no longer need to utilize predominately all of the Bammel Storage facility s working gas capacity for supplying CenterPoint s winter needs. This may reduce our working capital requirements that were necessary to finance the working gas while in storage and may provide us an opportunity to offer storage to third parties.

In connection with the Partnership s acquisition of the ET Fuel System in June 2004, it entered into an eight year transportation agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 115,600 MMBtu per year (reduced to 100,000 MMBtu per year in January, 2006). As of May 31, 2007 and 2006, respectively, the Partnership was entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month periods then ended. As a result, the Partnership recognized approximately $10,800 and $14,700 in additional fees during the three months ended May 31, 2007 and 2006, respectively.

In connection with our acquisition of the HPL System in 2004, we assumed a contract with a service provider which obligated us to obtain certain compression, measurement and other services through 2007 with monthly payments of approximately $1,700. We terminated the measurement portion of this contract in October 2006 for a payment of approximately $7,000. The remaining compression services total approximately $800 per month through October 2007.

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 coverages 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.

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

Transwestern is managing one threatened trespass action related to right of way (ROW) on Tribal or allottee land. The threatened action concerns 5,100 feet of ROW on private allotments within the Laguna Pueblo that expired on December 28, 2002. Transwestern received a letter dated March 19, 2003 from the United States Department of the Interior, Bureau of Indian Affairs (BIA) on behalf of the two allottees asserting trespass. Transwestern s legal exposure related to this matter is not currently determinable. Negotiations are ongoing on this matter.

Another action involves an agreement with the BIA covering 44 miles of ROW on a total of 68 Navajo allotments. This ROW agreement expired on January 1, 2004. One allottee sent a letter dated January 16, 2004 to the BIA claiming Transwestern trespassed and that allotee s claim of trespass has been settled and his consent to use the property has been acquired. Transwestern filed a renewal application with the BIA during October 2002, and has received two grants from the BIA for allotted lands in New Mexico and Arizona, which are effective through December 31, 2023.

At the time of the HPL acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel Storage facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation . Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory. The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters.

Following the natural gas market disruptions and related natural gas price volatility occurring in the Houston Ship Channel market around the times of the hurricanes in the fall of 2005, federal regulatory agencies commenced inquiries into certain activities during this period. Subsequently, the FERC and the Commodity Futures Trading Commission (CFTC) initiated investigations into whether ETP engaged in manipulative or improper trading activities in the Houston Ship Channel market around the times of the hurricanes in the fall of 2005, as well as other prior periods, in order to benefit financially from our commodities derivative positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel market. FERC is also investigating certain of ETP s intrastate transportation activities. In connection with these investigations, we have responded to discovery subpoenas of, and have otherwise provided information to, these agencies concerning our physical sales of natural gas and financial derivatives transactions, along with certain natural gas transportation activities, during the periods covered by the investigations. It is our position that our trading and transportation activities during these periods complied in all material respects with applicable rules and regulations; however, the laws and regulations in this area, particularly as they relate to alleged market manipulation, are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC and CFTC hold substantial enforcement authority, including the ability to assess fines of up to $1 million per day per violation, to order the disgorgement of profits, and to recommend criminal penalties. We have recently engaged in discussions with these agencies related to their views of possible violations of applicable laws and regulations, and potential penalties related thereto, as well as settlement negotiations to resolve these matters. Management believes that these agencies will require a payment in order to conclude these investigations on a negotiated settlement basis. Our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the final outcome of these matters, including whether private rights of action or other proceedings related to the investigation may occur, and whether our existing accrual for financial reporting purposes will be sufficient to resolve all such matters.

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

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

As of May 31, 2007 and August 31, 2006, an accrual of $30,301 and $32,148, respectively, was recorded as accrued and other current liabilities and other non-current liabilities on our condensed consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters.

Environmental

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

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include remediation of several compressor sites on the Transwestern system for presence of polychlorinated biphenyls (PCBs) which are not eligible for recovery in rates. The total accrued future estimated cost of remediation activities expected to continue for several years is $12,937. Transwestern received FERC approval for rate recovery of the portion of soil and groundwater remediation not related to PCBs effective April 1, 2007.

Transwestern continues to incur certain costs related to PCBs that migrated into customers facilities. Because of the continued detection of PCBs in the customers facilities downstream of Transwestern s Topock and Needles stations, Transwestern, as part of ongoing arrangements with customers, continues to incur costs associated with containing and removing the PCBs. Costs of these remedial activities totaled approximately $259 for the period since acquisition. Future costs cannot be reasonably estimated because remediation activities are undertaken as claims are made by customers and former customers, and accordingly, no accrual has been established for these costs at May 31, 2007. However, such future costs are not expected to have a material impact on our financial position, results of operations or cash flows.

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

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

In conjunction with the October 1, 2002 acquisition of the Texas and Oklahoma natural gas gathering and gas processing assets from Aquila Gas Pipeline, Aquila, Inc. (Aquila) agreed to indemnify us for any environmental liabilities that arose from the operation of the assets for the period prior to October 1, 2002. Aquila also agreed to indemnify us for 50% of any environmental liabilities that arose from the operations of Oasis Pipe Line Company prior to October 1, 2002.

We also assumed certain environmental remediation matters related to eleven sites in connection with our acquisition of HPL.

Petroleum-based contamination or environmental wastes are known to be located on or adjacent to six sites on which HOLP presently has, or formerly had, retail propane operations. These sites were evaluated at the time of their acquisition. In all cases, remediation operations have been or will be undertaken by others, and in all six cases, HOLP obtained indemnification rights for expenses associated with any remediation from the former owners or related entities. We have not been named as a potentially responsible party at any of these sites, nor have our operations contributed to the environmental issues at these sites. Accordingly, no amounts have been recorded in our May 31, 2007 or August 31, 2006 condensed consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

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

As of May 31, 2007 and August 31, 2006, an accrual on an undiscounted basis of $17,345 and $4,387, respectively, was recorded in our condensed consolidated balance sheets as accrued and other current liabilities and other non-current liabilities to cover material environmental liabilities related to certain matters assumed in connection with the HPL acquisition, the Transwestern acquisition, and the potential environmental liabilities for three sites that were formerly owned by Titan or its predecessors. A receivable of $388 was recorded in our condensed consolidated balance sheets as of May 31, 2007 and August 31, 2006 to account for a predecessor s share of certain environmental liabilities of ETC OLP.

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

Our operations are subject to regulation by the U.S Department of Transportation (DOT) under the Hazardous Liquids Pipeline Safety Act (HLPSA) pursuant to which the DOT has established regulations relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the DOT, 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. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with these federal regulations and analogous state pipeline integrity requirements for our existing transportation assets other than Transwestern Pipeline will result in capital costs of $15,746 during the period between the remainder of calendar year 2007 through 2008, as well as operating and maintenance costs of $17,927 during that period. During this same time period, we estimate that we will incur pipeline integrity operating and maintenance costs of $8,500 with respect to our Transwestern Pipeline. Through May 31, 2007, a total of $11,800 of capital costs and $12,000 of operating and maintenance costs have been incurred for pipeline integrity testing. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

16. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:
Accounting for Derivative Instruments and Hedging Activities

We apply Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) as amended to account for our derivative financial instruments. This statement requires that all derivatives be recognized in the balance sheet as either an asset or liability measured at fair value. Special accounting for qualifying cash flow hedges allows a derivative s gains and losses to offset related results on the hedged item in the statement of operations and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

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

We use a combination of financial instruments including, but not limited to, futures, price swaps, options and basis swaps to manage our exposure to market fluctuations in the prices of natural gas and NGLs. We enter into these financial instruments with brokers who are clearing members with NYMEX and directly with counterparties in the over-the-counter (OTC) market. We are subject to margin deposit requirements under the OTC agreements and NYMEX positions. NYMEX requires brokers to obtain an initial margin deposit based on an expected volume of the trade when the financial instrument is initiated. This amount is paid to the broker by both counterparties of the financial instrument to protect the broker from default by one of the counterparties when the financial instrument settles. We also have maintenance margin deposits with certain counterparties in the OTC market. The payments on margin deposits occur 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. We had net deposits with derivative counterparties of $46,579 and $87,806 as of May 31, 2007 and August 31, 2006, respectively, reflected as deposits paid to vendors on our consolidated balance sheets.

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Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGL and propane prices. To reduce the impact of this price volatility, we primarily use derivative commodity instruments (futures and swaps) to manage our exposure to fluctuations in commodity prices. We have established a formal risk management policy in which derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction. At inception of a hedge, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness and how any ineffectiveness will be measured and recorded. We also assess, both at the inception of the hedge and on a quarterly basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows. If we determine that a derivative is no longer highly effective as a hedge, we discontinue hedge accounting prospectively by including changes in the fair value of the derivative in current earnings. Furthermore, on a bi-weekly basis, management reviews the creditworthiness of the derivative counterparties to manage against the risk of default.

The market prices used to value our financial derivatives and related transactions have been determined using independent third party prices, readily available market information, broker quotes and appropriate valuation techniques.

Non-trading Activities

We utilize various exchange-traded and over-the-counter commodity financial instrument contracts to limit our exposure to margin fluctuations in natural gas, NGL and propane prices. These contracts consist primarily of futures and swaps and are recorded at fair value on the consolidated balance sheets. If we designate a derivative financial instrument as a cash flow hedge and it qualifies for hedge accounting, a change in the fair value is deferred in Accumulated Other Comprehensive Income (OCI) until the underlying hedged transaction occurs. Any ineffective portion of a cash flow hedge s change in fair value is recognized each period in earnings. Realized gains and losses on derivative financial instruments that are designated as cash flow hedges are included in cost of products sold in the period the hedged transactions occur. Gains and losses deferred in OCI related to cash flow hedges remain in OCI until the underlying physical transaction occurs, unless it is probable that the forecasted transaction will not occur by the end of the originally specified time period or within an additional two-month period of time thereafter. For those financial derivative instruments that do not qualify for hedge accounting the change in market value is recorded in cost of products sold in the consolidated statements of operations. We reclassified into earnings gains of $20,205 and $142,921 for the three and nine months ended May 31, 2007, respectively, and gains of $2,789 and $44,463 for the three and nine months ended May 31, 2006, respectively, related to commodity financial instruments that were previously reported in OCI.

We expect losses of $7,898 to be reclassified into earnings over the next twelve months related to income currently reported in OCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs. The majority of our commodity-related derivatives are expected to settle within the next two years.

In the course of normal operations, we routinely enter into contracts such as forward physical contracts for the purchase and sale of natural gas, propane, and other NGLs, that under SFAS 133, qualify for and are designated as a normal purchase and sales contracts. Such contracts are exempted from the fair value accounting requirements of SFAS 133 and are accounted for using accrual accounting. For contracts that are not designated as normal purchase and sales contracts, the change in market value is recorded in costs of products sold in the consolidated statements of operations. In connection with the HPL acquisition, we acquired certain physical forward contracts that contain embedded options. These contracts have not been designated as normal purchase and sale contracts, and therefore, are marked to market in addition to the financial options that offset them. The Black-Scholes valuation model was used to estimate the value of these embedded options.

Trading Activities

Trading activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain strategies are considered trading for accounting purposes and are executed with the use of a combination of financial instruments including, but not limited to, basis contracts and gas daily contracts. The derivative contracts that are entered into for trading purposes, subject to limits, are recognized on the consolidated balance sheets at fair value. The changes in the fair value of these derivative instruments are recognized in midstream and intrastate transportation and storage revenue in the consolidated statements of operations on a net basis. Net losses associated with trading activities for the three and nine months ended May 31, 2007 were $1,753 and $509, respectively. Included in the trading revenue was unrealized losses of $2,282 and $19,810 for the three and nine months ended May 31, 2007, respectively. For the three and nine months ended May 31, 2006, trading activities consisted of gains of $6,323 and $56,160, respectively, including unrealized losses of $1,064 and $20,181, respectively.

The following table details the outstanding commodity-related derivatives as of May 31, 2007 and August 31, 2006, respectively:

May 31, 2007	**Commodity**	**Notional Volume MMBTU**	**Maturity**	**Fair Value**
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	19,169,697	2007-2009	$ 7,746
Swing Swaps IFERC	Gas	(4,942,500)	2007-2008	365
Fixed Swaps/Futures	Gas	(9,867,500)	2007-2009	(1,705)
Forward Physical Contracts	Gas	(12,584,549)	2007-2008	128
Options	Gas	(1,038,000)	2007-2008	(176)
Propane Swaps - in Gallons	Propane	882,000	2007-2008	12
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,747,500	2007-2008	$ 2,666
Swing Swaps IFERC	Gas	3,300,000	2007	(249)
Forward Physical Contracts	Gas		2007	(352)
Fixed Swaps/Futures	Gas	(300,000)	2007	21
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(21,407,500)	2007-2009	$ (291)
Fixed Swaps/Futures	Gas	(22,332,500)	2007-2009	(1,918)
August 31, 2006				
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	33,711,140	2006-2009	$ (6,247)
Swing Swaps IFERC	Gas	(37,220,448)	2006-2008	2,618
Fixed Swaps/Futures	Gas	3,607,500	2006-2007	(170)
Forward Physical Contracts	Gas	(7,986,000)	2006-2008	(21,653)
Options	Gas	(1,046,000)	2006-2008	21,653
Forward/Swaps - in Gallons	Propane	24,066,000	2006-2007	199
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(2,572,500)	2006-2008	$ 21,995
Swing Swaps IFERC	Gas		2006	(31)
Forward Physical Contracts	Gas	(455,000)	2006	(68)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(34,585,000)	2006-2007	$ (2,987)
Fixed Swaps/Futures	Gas	(37,872,500)	2006-2007	2,043

Estimates related to our gas marketing activities are sensitive to uncertainty and volatility inherent in the energy commodities markets and actual results could differ from these estimates. We also attempt to maintain balanced positions in our non-trading 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 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, will be offset with financial contracts to balance our positions. To the extent open commodity positions exist in our trading and non-trading activities, fluctuating commodity prices can impact our financial results and financial position, either favorably or unfavorably.

During the nine months ended May 31, 2007 and 2006, the Partnership discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified for and designated as cash flow hedges related to forecasted sales of natural gas stored in the Partnership s Bammel storage facilities. The discontinuation resulted from management s determination that the originally forecasted sales of natural gas from the storage facilities were no longer probable of occurring by the end of the originally specified time period, or within an additional two-month period of time thereafter. The determination was made principally due to the unseasonably warm weather that occurred during February and March of 2006 and 2007. One of the key criteria to achieve hedge accounting under SFAS 133 is that the forecasted transaction be probable of occurring as originally set forth in the hedge documentation. As a result, during the three months ended May 31, 2007, the Partnership recognized previously deferred unrealized gains of $19,321 from the discontinued application of hedge accounting, which is included in the reclassification into earnings from OCI. The Partnership recognized previously deferred gains of $37,169 and $84,680 from the discontinued application of hedge accounting during the nine months ended May 31, 2007 and 2006, respectively. The Partnership classified the unrealized gains as costs of products sold in its consolidated statements of operations.

Interest Rate Risk

We are exposed to market risk for changes in interest rates related to our bank credit facilities. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements which allow us to effectively convert a portion of variable rate debt into fixed rate debt. Certain of our interest rate derivatives are accounted for as cash flow hedges. We report the realized gain or loss and ineffectiveness portions of those hedges in interest expense. Gains and losses on interest rate derivatives that are not cash flow hedges are classified in other income beginning in fiscal 2007. Prior to fiscal 2007, such gains or losses were reported in interest expense.

We entered into forward starting interest rate swaps with a notional value of $600,000 during the three months ended May 31, 2007. The fair value of the swaps was recorded as an asset of $15,733 on the consolidated balance sheet as of May 31, 2007. We did not apply hedge accounting to these instruments; therefore, changes in the fair value of these swaps were recorded as other income on the condensed consolidated statements of operations. These swaps were terminated in June 2007 for a gain of approximately $31,500.

We entered into forward starting interest swaps with a notional value of $400,000 during the three months ended August 31, 2006. The fair value of the swaps was recorded as a liability of $8,699 on the condensed consolidated balance sheets as of August 31, 2006. The swaps were accounted for as cash flow hedges under SFAS 133 and recorded as a component of OCI, to be reclassified to interest expense in the future as the related interest payments are made. These interest swaps were terminated in April, 2007 at a cost of approximately $13,400.

We entered into treasury locks and interest rate swaps with a notional amount of $300,000 during the third fiscal quarter of 2006. We elected to not apply hedge accounting to these financial instruments. These instruments settled during the nine months ended May 31, 2007 for a gain of $567.

In connection with the Titan acquisition, we assumed a three year LIBOR interest rate swap with a notional amount of $125,000. The fair value of this swap as of May 31, 2007 and August 31, 2006 was a net asset of $170 and $519, respectively, and was recorded as a component of price risk management assets and liabilities in the condensed consolidated balance sheet. We elected to not apply hedge accounting to these financial instruments. Changes in the fair value of these instruments are recorded as other income on the condensed consolidated statements of operations.

We reclassified into earnings losses of $1,119 and $1,170 for the three and nine months ended May 31, 2007, respectively, related to interest rate swaps that were previously reported in OCI. Gains of $67 and $823 were reclassified into earnings for the three and nine months ended May 31, 2006 related to interest rate swaps

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previously reported in OCI. We expect gains of $417 to be reclassified into earnings over the next twelve months related to income on interest rate financial instruments currently reported in OCI. The amount ultimately realized, however, will differ as interest rates change.

Summary of Derivative Gains and Losses

The following represents gains (losses) on derivative activity for the periods presented:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	**2006**	**2007**	**2006**
Commodity-related				
Unrealized losses recognized in revenues and cost of products sold related to commodity-related derivative activity, excluding ineffectiveness	$ (25,726)	$ (46,317)	$ (9,841)	$ (8,508)
Ineffective portion of derivatives qualifying for hedge accounting	(1,240)	1,430	242	18,753
Realized gains included in revenues and cost of products sold	52,671	57,600	166,537	158,055
Interest rate swaps				
Unrealized gains on interest rate swaps included in other income (2007) and interest expense (2006), excluding ineffectiveness	$ 16,328	$ 9,304	$ 14,755	$ 9,153
Ineffective portion of derivatives qualifying for hedge accounting included in interest expense	(1,377)	75	(1,813)	846
Realized gains (losses) on interest rate swaps included in interest expense	346	(8)	1,483	127

Credit Risk

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

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

17. RELATED PARTY TRANSACTIONS:

On May 7, 2007, Ray Davis, Co-Chairman and Co-Chief Executive Officer of ETP, and Natural Gas Partners VI, L.P. (NGP) and affiliates of each, sold approximately 38.9 million ETE Common Units (17.6% of the outstanding Common Units of ETE) to Enterprise GP Holdings, L.P. (Enterprise or EPE). In addition to the purchase of ETE Common Units, Enterprise also acquired a 34.9% non-controlling equity interest in the General Partner of ETE, LE GP, L.L.C. (LE GP). As a result of these transactions, EPE and its subsidiaries are considered related parties (see Note 15).

Between May 7, 2007 (the purchase date of ETE Units) and May 31, 2007, the Operating Partnerships have made the following purchases from Enterprise and its affiliates:

	Product	Volumes (in thousands)	Dollars
HOLP	Propane-gallons	2,879	$ 3,452

Titan	Propane-gallons	9,492	10,010
ETC OLP	Gas imbalances - MMBtu	185	1,905
Total			$ 15,367

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Additionally, HOLP has a monthly storage contract with TEPPCO Partners, L.P. (an affiliate of Enterprise).

ETC OLP and Enterprise transport gas on each other s systems, share operating expenses on jointly-owned pipelines, and ETC OLP sells gas to Enterprise. As of May 31, 2007, ETC OLP has an accounts receivable balance of approximately $1,800, an accounts payable balance of approximately $200 and an imbalance payable to Enterprise of approximately $11,200.

As of May 31, 2007 and August 31, 2006, we had advances due from a propane joint venture of $11,769 and $3,775, respectively, which are included in intangibles and other long-term assets on our condensed consolidated balance sheets.

Our natural gas midstream and intrastate transportation and storage operations secure compression services from third parties including Energy Transfer Technologies, Ltd., of which Energy Transfer Group, LLC is the General Partner. These entities are collectively referred to as the ETG Entities . Our Co-Chief Executive Officers have an indirect ownership in the ETG Entities. In addition, two of the General Partner s directors serve on the Board of Directors of the ETG Entities. The terms of each arrangement to provide compression services are, in the opinion of independent directors of the General Partner, no less favorable than those available from other providers of compression services. During the nine months ended May 31, 2007 and 2006, we made payments totaling $1,989 and $5,901, respectively, to the ETG Entities for compression services provided to and utilized in our natural gas midstream and intrastate transportation and storage operations. As of May 31, 2007 and August 31, 2006, accounts payable to ETG related to compressor leases were not significant.

18. SUMMARIZED CONDENSED CONSOLIDATING FINANCIAL STATEMENTS:

Our Revolving Credit Facility and Senior Notes are fully and unconditionally guaranteed by ETC OLP and Titan and all of their direct and indirect wholly-owned subsidiaries (the Subsidiary Guarantors). HOLP and its direct and indirect subsidiaries, Heritage Holdings, Inc. and Transwestern do not guarantee our Revolving Credit Facility and Senior Notes. The Subsidiary Guarantors jointly and severally guarantee, on an unsecured senior basis, our obligations under our Revolving Credit Facility and Senior Notes. Following are our unaudited condensed consolidating financial information including our midstream, interstate, and propane Subsidiary Guarantors, our Non-Guarantor Subsidiaries and the Partnership on a consolidated basis. The condensed consolidating financial information presented herein complies with Rule 3-10 of Regulation S-X, is prepared on the equity method, and does not contain related financial statement disclosures that would be required with a complete set of financial statements presented in conformity with GAAP.

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING BALANCE SHEET

As of May 31, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 414	$	$ 13,950	$ 81,246	$	$ 95,610
Marketable securities				3,575		3,575
Accounts receivable, net		500,604	19,224	106,485	(974)	625,339
Inventories		246,470	11,090	40,316		297,876
Deposits paid to vendors		46,579				46,579
Exchanges receivable		27,639		12,906		40,545
Price risk management assets	15,733	9,999	212			25,944
Prepaid expenses and other	886,033	78,472	34,284	19,121	(977,908)	40,002
Total current assets	902,180	909,763	78,760	263,649	(978,882)	1,175,470
PROPERTY, PLANT AND EQUIPMENT, net		3,268,387	182,315	1,827,407		5,278,109
GOODWILL		23,736	258,586	434,121		716,443
LONG-TERM NOTES RECEIVABLE FROM RELATED PARTY	8,996		6,728		(15,724)	
DEFERRED INCOME TAX			4,990		(4,990)	
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	5,011,563	35,951	68,815	394,478	(5,111,477)	399,330
Total assets	$ 5,922,739	$ 4,237,837	$ 600,194	$ 2,919,655	$ (6,111,073)	$ 7,569,352
LIABILITIES AND PARTNERS' CAPITAL						
CURRENT LIABILITIES:						
Accounts payable	$ 155	$ 525,166	$ 2,922	$ 57,167	$ (974)	$ 584,436
Exchanges payable		38,973		9,215		48,188
Customer advances and deposits		6,625	9,387	24,542		40,554
Accrued and other current liabilities	68,873	1,036,764	26,577	107,391	(977,908)	261,697
Price risk management liabilities		1,866				1,866
Current maturities of long-term debt			516	39,252		39,768
Total current liabilities	69,028	1,609,394	39,402	237,567	(978,882)	976,509
LONG-TERM DEBT, net of discount, less current maturities	2,680,364		694	745,550		3,426,608
LONG-TERM NOTES PAYABLE FROM RELATED PARTY	6,728			8,996	(15,724)	
DEFERRED INCOME TAXES		50,579		54,892	(4,990)	100,481
OTHER NONCURRENT LIABILITIES		1,952	2,961	11,906		16,819
COMMITMENTS AND CONTINGENCIES						

	2,756,120	1,661,925	43,057	1,058,911	(999,596)	4,520,417
PARTNERS CAPITAL	3,166,619	2,575,912	557,137	1,860,744	(5,111,477)	3,048,935
Total liabilities and partners capital	$ 5,922,739	$ 4,237,837	$ 600,194	$ 2,919,655	$ (6,111,073)	$ 7,569,352

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING BALANCE SHEET

As of August 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 728	$	$ 2,182	$ 23,131	$	$ 26,041
Marketable securities				2,817		2,817
Accounts receivable, net		570,569	18,154	86,822		675,545
Inventories		289,003	13,507	84,630		387,140
Deposits paid to vendors		87,806				87,806
Exchanges receivable		23,221				23,221
Price risk management assets	629	55,143	367			56,139
Prepaid expenses and other	399,813	41,426	24,511	12,888	(435,543)	43,095
Total current assets	401,170	1,067,168	58,721	210,288	(435,543)	1,301,804
PROPERTY, PLANT AND EQUIPMENT, net		2,596,015	201,893	515,741		3,313,649
GOODWILL		23,736	278,835	301,838		604,409
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	3,848,223	38,864	79,612	229,686	(3,961,234)	235,151
Total assets	$ 4,249,393	$ 3,725,783	$ 619,061	$ 1,257,553	$ (4,396,777)	$ 5,455,013
LIABILITIES AND PARTNERS' CAPITAL						
CURRENT LIABILITIES:						
Accounts payable	$ 1,244	$ 522,191	$ 4,955	$ 74,750	$	$ 603,140
Exchanges payable		24,722				24,722
Customer advances and deposits		16,524	24,623	67,689		108,836
Accrued and other current liabilities	45,261	533,831	22,512	36,235	(435,543)	202,296
Price risk management liabilities	8,699	28,219				36,918
Current maturities of long-term debt			871	39,707		40,578
Total current liabilities	55,204	1,125,487	52,961	218,381	(435,543)	1,016,490
LONG-TERM DEBT, net of discount, less current maturities	2,330,281		679	258,164		2,589,124
DEFERRED INCOME TAXES		51,253		55,589		106,842
OTHER NONCURRENT LIABILITIES		3,838		1,857		5,695
COMMITMENTS AND CONTINGENCIES						
	2,385,485	1,180,578	53,640	533,991	(435,543)	3,718,151
PARTNERS CAPITAL	1,863,908	2,545,205	565,421	723,562	(3,961,234)	1,736,862
Total liabilities and partners capital	$ 4,249,393	$ 3,725,783	$ 619,061	$ 1,257,553	$ (4,396,777)	$ 5,455,013

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the three months ended May 31, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 1,344,884	$	$ 61,714	$	$ 1,406,598
Propane and other	357		76,789	231,042		308,188
Total revenue	357	1,344,884	76,789	292,756		1,714,786
COSTS AND EXPENSES:						
Cost of products sold - midstream and transportation and storage		1,095,040				1,095,040
Cost of products sold - propane and other			44,092	148,255		192,347
Operating expenses		60,155	21,280	67,468		148,903
Depreciation and amortization		20,693	3,334	23,375		47,402
Selling, general and administrative	1,057	24,414	333	13,982		39,786
Total costs and expenses	1,057	1,200,302	69,039	253,080		1,523,478
OPERATING INCOME (LOSS)	(700)	144,582	7,750	39,676		191,308
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(44,527)	(5,551)	591	(12,191)	15,529	(46,149)
Equity in earnings (losses) of affiliates	172,648	544		296	(172,649)	839
Gain (loss) on disposal of assets		(2,770)	374	(104)		(2,500)
Interest and other income (expense), net	30,466	2,099	(3)	718	(15,529)	17,751
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	157,887	138,904	8,712	28,395	(172,649)	161,249
Income tax expense	421	2,039	89	1,011		3,560
INCOME BEFORE MINORITY INTERESTS	157,466	136,865	8,623	27,384	(172,649)	157,689
Minority interests				(223)		(223)
NET INCOME	$ 157,466	$ 136,865	$ 8,623	$ 27,161	$ (172,649)	$ 157,466

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the three months ended May 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:					
Midstream and transportation and storage	$	$ 1,211,549	$	$	$ 1,211,549
Propane and other			208,786		208,786
Total revenues		1,211,549	208,786		1,420,335
COSTS AND EXPENSES:					
Cost of products sold - midstream and transportation and storage		1,020,692			1,020,692
Cost of products sold - propane and other			126,675		126,675
Operating expenses		51,535	51,434		102,969
Depreciation and amortization		14,381	13,768		28,149
Selling, general and administrative	3,698	15,858	4,176		23,732
Total costs and expenses	3,698	1,102,466	196,053		1,302,217
OPERATING INCOME (LOSS)	(3,698)	109,083	12,733		118,118
OTHER INCOME (EXPENSE):					
Interest expense, net of interest capitalized	(10,754)	3,343	(6,733)	470	(13,674)
Equity in earnings (losses) of affiliates	126,074	(272)	122	(126,074)	(150)
Gain (loss) on disposal of assets		31	(9)		22
Interest and other income (expense), net	291	1,897	7,954	(470)	9,672
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	111,913	114,082	14,067	(126,074)	113,988
Income tax expense	1	773	1,207		1,981
INCOME BEFORE MINORITY INTERESTS	111,912	113,309	12,860	(126,074)	112,007
Minority interests			(95)		(95)
NET INCOME	$ 111,912	$ 113,309	$ 12,765	$ (126,074)	$ 111,912

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the nine months ended May 31, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 3,842,008	$	$ 119,872	$	$ 3,961,880
Propane and other	357		311,896	891,578		1,203,831
Total revenue	357	3,842,008	311,896	1,011,450		5,165,711
COSTS AND EXPENSES:						
Cost of products sold - midstream and transportation and storage		3,117,732				3,117,732
Cost of products sold - propane and other			184,226	558,588		742,814
Operating expenses		158,087	67,112	189,894		415,093
Depreciation and amortization		55,187	9,291	62,093		126,571
Selling, general and administrative	4,286	65,188	2,735	33,780		105,989
Total costs and expenses	4,286	3,396,194	263,364	844,355		4,508,199
OPERATING INCOME (LOSS)	(3,929)	445,814	48,532	167,095		657,512
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(118,502)	(8,649)	(617)	(32,694)	32,079	(128,383)
Equity in earnings (losses) of affiliates	616,910	(219)		320	(611,799)	5,212
Gain (loss) on disposal of assets		(5,156)		1,371		(3,785)
Interest and other income, net	45,554	5,343	1,153	874	(32,079)	20,845
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	540,033	437,133	49,068	136,966	(611,799)	551,401
Income tax expense (benefit)	421	5,451	(1,265)	5,849		10,456
INCOME BEFORE MINORITY INTERESTS	539,612	431,682	50,333	131,117	(611,799)	540,945
Minority interests				(1,333)		(1,333)
NET INCOME	$ 539,612	$ 431,682	$ 50,333	$ 129,784	$ (611,799)	$ 539,612

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the nine months ended May 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:					
Midstream and transportation and storage	$	$ 5,503,385	$	$	$ 5,503,385
Propane and other			783,386		783,386
Total revenues		5,503,385	783,386		6,286,771
COSTS AND EXPENSES:					
Cost of products sold - midstream and transportation and storage		4,765,113			4,765,113
Cost of products sold - propane and other			481,712		481,712
Operating expenses		154,125	151,211		305,336
Depreciation and amortization		42,742	41,334		84,076
Selling, general and administrative	12,718	54,027	13,241		79,986
Total costs and expenses	12,718	5,016,007	687,498		5,716,223
OPERATING INCOME (LOSS)	(12,718)	487,378	95,888		570,548
OTHER INCOME (EXPENSE):					
Interest expense, net of interest capitalized	(53,822)	(849)	(22,515)	6,577	(70,609)
Equity in earnings (losses) of affiliates	543,165	(289)	(29)	(543,165)	(318)
Gain (loss) on disposal of assets		625	(69)		556
Interest and other income, net	5,881	5,835	7,794	(6,577)	12,933
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	482,506	492,700	81,069	(543,165)	513,110
Income tax expense	1	20,879	7,526		28,406
INCOME BEFORE MINORITY INTERESTS	482,505	471,821	73,543	(543,165)	484,704
Minority interests		(1,349)	(850)		(2,199)
NET INCOME	$ 482,505	$ 470,472	$ 72,693	$ (543,165)	$ 482,505

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the nine months ended May 31, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 404,807	$ 743,550	$ 89,429	$ 154,410	$ (522,923)	$ 869,273
CASH FLOWS FROM INVESTING ACTIVITIES:						
Cash paid for acquisitions, net of cash acquired	(5,205)	(70,671)	(5,319)	(9,678)	3,386	(87,487)
Capital expenditures		(700,870)	(8,611)	(89,764)		(799,245)
Advances to and investment in affiliates	(1,051,237)	(90)		(35,467)	100,000	(986,794)
Proceeds from the sale of assets		9,812	2,698	8,279		20,789
Net cash used in investing activities	(1,056,442)	(761,819)	(11,232)	(126,630)	103,386	(1,852,737)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from borrowings	2,868,310		798	400,649		3,269,757
Principal payments on debt	(2,515,822)	(16,261)	(665)	(447,061)		(2,979,809)
Proceeds from borrowings from affiliates	3,221,121	3,161,991	157,217	386,127	(6,926,456)	
Payments on borrowings from affiliates	(3,676,665)	(2,731,519)	(164,269)	(354,003)	6,926,456	
Net proceeds from issuance of Common Units	1,200,000					1,200,000
Capital contribution from General Partner	24,490			100,000	(100,000)	24,490
Distributions to parent		(395,942)	(59,510)	(58,108)	513,560	
Distributions to partners	(461,180)				9,363	(451,817)
Debt issuance costs	(8,933)			(655)		(9,588)
Net cash provided by (used in) financing activities	651,321	18,269	(66,429)	26,949	422,923	1,053,033
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(314)		11,768	54,729	3,386	69,569
CASH AND CASH EQUIVALENTS, beginning of period	728		2,182	26,517	(3,386)	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 414	$	$ 13,950	$ 81,246	$	$ 95,610

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the nine months ended May 31, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (57,755)	$ 490,121	$ 95,429	$	$ 527,795
CASH FLOWS FROM INVESTING ACTIVITIES:					
Cash paid for acquisitions, net of cash acquired		(17,124)	(18,825)		(35,949)
Working capital settlement on prior year acquisitions		19,653			19,653
Capital invested in subsidiaries	(132,387)			132,387	
Capital expenditures		(476,017)	(34,555)		(510,572)
Proceeds from the sale of assets		2,502	2,049		4,551
Net cash used in investing activities	(132,387)	(470,986)	(51,331)	132,387	(522,317)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	1,388,251		196,806		1,585,057
Proceeds from short term borrowings from affiliates	1,128,579	1,245,649		(2,374,228)	
Principal payments on debt	(1,208,605)		(278,095)		(1,486,700)
Principal payments received from affiliates	(1,245,649)	(1,128,579)		2,374,228	
Distributions to parent	(7,314)	(193,630)	(40,104)	241,048	
Distributions from subsidiaries	233,734		7,314	(241,048)	
Debt issuance costs	(1,295)				(1,295)
Net proceeds from issuance of limited partner units	132,383				132,383
Capital contribution from General Partner	2,702	57,387	75,000	(132,387)	2,702
Unit distributions	(235,894)				(235,894)
Net cash provided by (used in) financing activities	186,892	(19,173)	(39,079)	(132,387)	(3,747)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(3,250)	(38)	5,019		1,731
CASH AND CASH EQUIVALENTS, beginning of period	3,810	38	21,066		24,914
CASH AND CASH EQUIVALENTS, end of period	$ 560	$	$ 26,085	$	$ 26,645

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19. REPORTABLE SEGMENTS:

As of May 31, 2007, our financial statements reflect five reportable segments:

ETC OLP:

- midstream operations
- intrastate transportation and storage operations

ET Interstate:

- interstate transportation operations

HOLP and Titan:

- retail propane operations

HOLP:

- wholesale propane operations, including the operations of MP Energy Partnership

As of December 1, 2006, with the completion of our acquisition of Transwestern, we have a new reporting segment for our interstate transportation operations. As a result, the comparability of the segment operations information is affected by this addition. The volumes and results of operations data for the three months ended May 31, 2007 include the interstate operations for the entire period. However, the three and nine month volumes and results of operations do not include the interstate operations for periods prior to December 1, 2006.

Segments below the quantitative thresholds are classified as other . None of the components of the other segment have ever met any of the quantitative thresholds for determining reportable segments. Management has combined the domestic wholesale propane and foreign wholesale propane segments into one segment for all periods presented in this report. The combined segment is referred to as the wholesale propane segment.

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

The midstream operations focus on the gathering, compression, treating, blending, processing, and marketing of natural gas, primarily on or through the Southeast Texas System, and marketing operations related to our producer services business. Revenue is primarily generated by the volumes of natural gas gathered, compressed, treated, processed, transported, purchased and sold through our pipelines (excluding the transportation pipelines) and gathering systems as well as the level of natural gas and NGL prices.

The intrastate transportation and storage operations focus on transporting natural gas through our Oasis Pipeline, ET Fuel System, East Texas Pipeline System, HPL System and Fort Worth Basin Pipeline. Revenue is typically generated from fees charged to customers to reserve firm capacity on or move gas through the pipeline on an interruptible basis. A monetary fee and/or fuel retention are also components of the fee structure. Excess fuel retained after consumption is typically valued at the first of the month published market prices and strategically sold when market prices are high. The intrastate transportation and storage operations also consist of the HPL System which generates revenue primarily from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies. The use of the Bammel storage reservoir allows us to purchase physical natural gas and then sell financial contracts at a price sufficient to cover its carrying costs and provide a gross profit margin. The HPL System also transports natural gas for a variety of third party customers.

The interstate transportation operations focus on natural gas transportation of Transwestern, which owns and operates approximately 2,400 miles of interstate natural gas pipeline system extending from Texas through the San Juan Basin to the California border. Transwestern is a major natural gas transporter to the California border and delivers natural gas from the east end of its system to Texas intrastate and Midwest markets. The revenues of this segment consist primarily of fees earned from natural gas transportation services and operational gas sales.

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Our retail and wholesale propane segments sell products and services to retail and wholesale customers. Intersegment sales by the foreign wholesale segment to the domestic segment are priced in accordance with the partnership agreement of MP Energy Partnership. We manage our propane segments separately as each segment involves different distribution, sale, and marketing strategies.

We evaluate the performance of our operating segments based on operating income exclusive of general partnership selling, general, administrative expenses, gain (loss) on disposal of assets, minority interests, interest expense, earnings (losses) from equity investments and income tax expense (benefit). Certain overhead costs relating to a reportable segment have been allocated for purposes of calculating operating income. Effective with the Transwestern acquisition on December 1, 2006, we began allocating administration expenses to our operating partnerships. The amounts of such allocations for the three and nine months, respectively, ended May 31, 2007 were approximately $1,171 and $2,860 to midstream, $1,265 and $2,760 to interstate transportation and $2,232 and $4,721 to propane, for a total of approximately $4,668 and $10,341.

The following table presents the financial information by segment for the following periods:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Volumes:				
Midstream				
Natural gas MMBtu/d - sold	1,042,641	1,216,424	948,242	1,423,414
NGLs bbls/d - sold	21,586	10,902	16,373	10,224
Transportation and storage				
Natural gas MMBtu/d transported	6,752,447	4,797,307	5,540,393	4,500,308
Natural gas MMBtu/d sold	1,204,609	1,303,033	1,388,337	1,572,451
Interstate transportation				
Natural gas MMBtu/d transported	1,802,486		1,765,677	
Natural gas MMBtu/d sold	22,247		20,382	
Propane gallons (in thousands)				
Retail	127,612	91,514	521,957	346,010
Wholesale	23,493	19,299	79,204	67,143
Total propane gallons	151,105	110,813	601,161	413,153

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Revenues:				
Midstream	$ 869,079	$ 789,966	$ 2,101,507	$ 3,544,821
Eliminations	(488,188)	(497,807)	(1,142,400)	(2,016,600)
Intrastate transportation and storage	963,993	919,390	2,882,901	3,975,164
Interstate transportation (see Note 3)	61,714		119,872	
Retail propane and other propane related	276,445	185,272	1,101,239	699,450
Wholesale propane	30,746	21,461	98,992	78,361
Other	997	2,053	3,600	5,575
Total revenues	$ 1,714,786	$ 1,420,335	$ 5,165,711	$ 6,286,771
Cost of Sales:				
Midstream	$ 812,815	$ 745,162	$ 1,945,245	$ 3,342,588
Eliminations	(488,188)	(497,807)	(1,142,400)	(2,016,600)
Intrastate transportation and storage	770,413	773,337	2,314,887	3,439,125

Retail propane and other propane related	163,500	106,153	650,214	408,467
Wholesale propane	28,847	19,959	92,072	71,671
Other		563	528	1,574
Total cost of sales	$ 1,287,387	$ 1,147,367	$ 3,860,546	$ 5,246,825

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	Three Months Ended May 31, 2007	Three Months Ended May 31, 2006	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
Depreciation and Amortization:				
Midstream	$ 6,226	$ 4,046	$ 16,410	$ 11,612
Intrastate transportation and storage	14,467	10,334	38,776	31,130
Interstate transportation	9,241		18,895	
Retail propane and other propane related	17,306	13,491	51,835	40,445
Wholesale propane	162	173	530	579
Other		105	125	310
Total depreciation and amortization	$ 47,402	$ 28,149	$ 126,571	$ 84,076

	Three Months Ended May 31, 2007	Three Months Ended May 31, 2006	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
Operating Income (Loss):				
Midstream	$ 30,172	$ 27,225	$ 86,790	$ 148,089
Intrastate transportation and storage	114,410	81,859	359,025	339,289
Interstate transportation	33,789		67,901	
Retail propane and other propane related	13,066	13,007	145,237	93,742
Wholesale propane	310	(442)	1,855	1,765
Other	652	172	1,025	391
Selling general and administrative expenses not allocated to segments	(1,091)	(3,703)	(4,321)	(12,728)
Total operating income	191,308	118,118	657,512	570,548
Other items not allocated by segment:				
Interest expense	(46,149)	(13,674)	(128,383)	(70,609)
Equity in earnings (losses) of affiliates	839	(150)	5,212	(318)
Gain (loss) on disposal of assets	(2,500)	22	(3,785)	556
Interest and other income, net	17,751	9,672	20,845	12,933
Income tax expense	(3,560)	(1,981)	(10,456)	(28,406)
Minority interests	(223)	(95)	(1,333)	(2,199)
	(33,842)	(6,206)	(117,900)	(88,043)
Net income	$ 157,466	$ 111,912	$ 539,612	$ 482,505

	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006
Additions to Property, Plant and Equipment including acquisitions (accrual basis):		
Midstream	$ 126,299	$ 16,737
Intrastate transportation and storage	653,708	475,165
Interstate transportation	1,305,242	
Retail propane and other propane related	54,336	48,058
Wholesale propane	45	314
Other	1,004	3,981
Total	$ 2,140,634	$ 544,255

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	May 31, 2007	August 31, 2006
Total Assets:		
Midstream	$ 748,665	$ 682,652
Intrastate transportation and storage	3,439,189	3,029,124
Interstate transportation	1,609,391	
Retail propane and other propane related	1,609,458	1,619,732
Wholesale propane	24,889	39,816
Other	137,760	83,689
Total	$ 7,569,352	$ 5,455,013

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

(Tabular dollar amounts, except per unit data, 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 fiscal year ended August 31, 2006 filed with the Securities and Exchange Commission on November 13, 2006. Our Management s Discussion and Analysis 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.

Overview

Midstream and Intrastate Transportation and Storage Segments

Through ETC OLP, we own and operate intrastate natural gas gathering and transportation pipelines, natural gas treating and processing assets located in Texas, Louisiana and New Mexico, and three natural gas storage facilities located in Texas. These assets include approximately 12,200 miles of intrastate pipeline in service, with an additional 400 miles of intrastate pipeline under construction.

Our midstream segment results are derived primarily from margins we realize for natural gas volumes that are gathered, transported, purchased and sold through our pipeline systems, processed at our processing and treating facilities, and the volumes of NGLs processed at our facilities. We also market natural gas on our pipeline systems in addition to other pipeline systems to realize incremental revenue on gas purchased, increase pipeline utilization and provide other services that are valued by our customers. In addition and in accordance with our commodity risk management policy, we generate income from limited trading activities. Our trading activities include purchasing and selling natural gas and the use of financial instruments, including basis and gas daily contracts.

Our intrastate transportation and storage segment consists of natural gas gathering and intrastate transportation pipelines as well as three natural gas storage facilities with approximately 74 Bcf in storage capacity. The results from our transportation and storage segment are primarily derived from the fees we charge to transport natural gas on our pipelines, including a fuel retention component. We also generate revenues and margin from the sale of natural gas to electric utilities, independent power plants, local distribution companies, industrial end-users, and other marketing companies on the HPL System. Generally, HPL purchases its natural gas from either the market (including purchases from our midstream segment s producer services) and from producers at the wellhead. To the extent the natural gas comes from producers, it is purchased at a discount to a specified price and resold to customers at the index price.

We also utilize our Bammel storage reservoir to engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. We purchase physical natural gas and then sell financial contracts at a price sufficient to cover our carrying costs and provide for a gross profit margin.

As a result of our trading activities and the use of derivative financial instruments that may not qualify for hedge accounting in our midstream and transportation and storage segments, the degree of earnings volatility that can occur may be significant, favorably or unfavorably, from period to period. We attempt to manage this volatility through the use of daily position and profit and loss reports provided to our risk management committee, which includes members of senior management, and predefined limits and authorizations set forth by our risk management policy as discussed in Note 16 in the accompanying condensed consolidated financial statements.

Interstate Transportation Segment

In connection with the acquisition of Transwestern on December 1, 2006, we also own 2,400 miles of interstate natural gas pipelines. The operating results for Transwestern are included in our results on a consolidated basis as of the acquisition date (December 1, 2006). Our Interstate Transportation Segment also includes our 50 percent interest in Midcontinent Express Pipeline (MEP), a joint development between Kinder Morgan Energy Partners, L.P. and ETP. As of, and for the period ended, May 31, 2007, the activity related to MEP was not material to our condensed consolidated results of operations, financial position or cash flows.

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Transwestern is an open-access natural gas interstate pipeline extending approximately 2,400 miles from the gas producing regions of West Texas, eastern and northwest New Mexico, and southern Colorado primarily to pipeline interconnects off the east end of its system and to the California market. Transwestern has access to three significant gas basins: the Permian Basin in West Texas and eastern New Mexico; the San Juan Basin in northwest New Mexico and southern Colorado; and the Anadarko Basin in the Texas and Oklahoma panhandle.

Natural gas sources from the San Juan basin and surrounding producing areas can be delivered to connecting pipelines and natural gas market hubs in the east as well as markets to the west like California. Transwestern s customers include local distribution companies, producers, marketers, electric power generators and industrial end-users.

Transwestern earns the majority of its revenue by entering into firm transportation contracts, reserving capacity for customers to transport natural gas in its pipelines, whereby customers pay for the transportation capacity on a system regardless of whether it is utilized. It also earns variable revenue from charges assessed on each unit of transportation provided. In addition, to the extent that the gas retained by Transwestern for the operation of its pipeline system is not consumed in its systems compressors, it is sold as operational gas when conditions warrant.

FERC regulates our interstate natural gas pipeline interests. Transwestern transports natural gas in interstate commerce. As a result, Transwestern qualifies as a natural gas company under the Natural Gas Act and is subject to the regulatory jurisdiction of FERC. In general, FERC has authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce, and its authority to regulate those services includes:

- rate structures;
- rates of return on equity;
- recovery of costs;
- the services that our regulated assets are permitted to perform;
- the acquisition, construction and disposition of assets; and
- to an extent, the level of competition in that regulated industry.

Under the Natural Gas Act, FERC has authority to regulate natural gas companies that provide natural gas pipeline transportation services in interstate commerce. Its authority to regulate those services includes the rates charged for the services, terms and conditions of service, certification and construction of new facilities, the extension or abandonment of services and facilities, the maintenance of accounts and records, the acquisition and disposition of facilities, the initiation and discontinuation of services, and various other matters. Natural gas companies may not charge rates that have not been determined to be just and reasonable by FERC. In addition, FERC prohibits natural gas companies from unduly preferring or unreasonably discriminating against any person with respect to pipeline rates or terms and conditions of service.

The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, existing rates may be challenged by complaint and proposed rate increases may be challenged by protest. We cannot assure you that FERC will continue to pursue its approach of pro-competitive policies as it considers matters such as pipeline rates and rules and policies that may affect rights of access to natural gas transportation capacity, transportation and storage facilities. Any successful complaint or protest against Transwestern s FERC-approved rates could have an adverse impact on our revenues associated with providing transmission services on Transwestern s pipelines.

Retail and Wholesale Propane Segments

Our propane related segments are operated by HOLP, Titan and their respective subsidiaries engaged in the sale, distribution and marketing of propane and other related products through their retail and wholesale segments, (the propane segments). HOLP and Titan derive their revenue primarily from the retail propane segment. We believe that we are the third largest retail propane marketer in the United States, based on retail gallons sold. We serve more than one million propane customers from 400 customer service locations extending from coast to coast.

The propane segments are margin-based businesses in which gross profits depend on the excess of sales price over propane supply cost. The market price of propane is often subject to volatile changes as a result of supply or other market conditions over which we have no control. Product supply contracts are generally one-year agreements subject to annual renewal and generally permit suppliers to charge posted prices (plus transportation costs) at the time of delivery or the current prices established at major delivery points. Since rapid increases in the wholesale cost of propane may not be immediately passed on to retail customers, such increases could reduce gross profits. We generally have attempted to reduce price risk by purchasing propane on a short-term basis. We have on occasion purchased for future resale significant volumes of propane for storage during periods of low demand, which generally occur during the summer months, at the then current market price, both at our customer service locations and in major storage facilities. In particular, our propane business is largely seasonal and dependent upon weather conditions in our service areas.

Historically, approximately two-thirds of our retail propane volume and substantially all of our propane-related operating income is attributable to sales during the six-month peak-heating season of October through March. This generally results in higher operating revenues and net income in the propane segments during the period from October through March of each year, and lower operating revenues and either net losses or lower net income during the period from April through September of each year. Consequently, sales and operating profits for the propane segments are concentrated in our first and second fiscal quarters; however, cash flow from operations is generally greatest during our second and third fiscal quarters when customers pay for propane purchased during the six-month peak-heating season. Sales to industrial and agricultural customers are much less weather sensitive.

A substantial portion of our propane is used in the heating-sensitive residential and commercial markets causing the temperatures in our areas of operations, particularly during the six-month peak-heating season, to have a significant effect on the financial performance of our propane operations. In any given area, sustained warmer-than-normal temperatures will tend to result in reduced propane use, while sustained colder-than-normal temperatures will tend to result in greater propane use. We use information about normal temperatures to help us understand how temperatures that are colder or warmer than normal affect historical results of operations and in preparing forecasts related to our future operations.

The retail propane segment s gross profit margins are not only affected by weather patterns, but also vary according to customer mix. Sales to residential customers generate higher margins than sales to certain other customer groups, such as commercial or agricultural customers. The wholesale propane segment s margins are substantially lower than retail margins. In addition, propane gross profit margins vary by geographical region. Accordingly, a change in customer or geographic mix can affect propane gross profit without necessarily affecting total revenues.

Amounts discussed below reflect 100% of the results of MP Energy Partnership, a Canadian general partnership in which HOLP owns a 60% interest.

Trends and Outlook

We believe our natural gas operations are positioned to provide increasing operating results based on the current levels of contracted and expected capacity to be taken by our customers, our expansion activity completed during the fiscal 2007 period, additional capacity resulting from pipeline projects expected to be completed within the next twelve to eighteen months, and incremental earnings related to the recently acquired Transwestern operations.

We expect our propane-related segment to realize overall volume increases during fiscal year 2007 due to the effects of the Titan acquisition. However, continued warmer than normal weather will negatively impact volumes. We expect to be able to offset the impact of weather-related reduced volumes with reduced operating costs and improved gross margins to the extent our marketplace will allow it. We also plan to continue our active propane acquisition strategy and to expand our internal growth initiatives.

Recent Developments

Transwestern Pipeline. On November 1, 2006, pursuant to agreements entered into with GE Energy Financial Services (GE) and Southern Union Company (Southern Union), we acquired the member interests in CCE Holdings, LLC (CCEH) from GE and certain other investors for $1.0 billion. We financed a portion of the CCEH purchase price with the proceeds from our issuance of approximately 26.1 million Class G Units to Energy Transfer Equity, L.P. simultaneous with the closing on November 1, 2006. The member interests acquired represented a 50% ownership in CCEH.

On December 1, 2006, in a second and related transaction, CCEH redeemed ETP s 50% interest ownership in CCEH in exchange for 100% ownership of Transwestern Pipeline Company, LLC which owns the Transwestern

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Pipeline, a 2,400 mile interstate natural gas pipeline. Following the final step, Transwestern became a new operating subsidiary and separate segment of ETP. Our total acquisition cost for Transwestern, including assumed debt, was approximately $1.536 billion, including our basis of $956.3 million in CCEH (see Note 3 to the condensed consolidated financial statements).

Midcontinent Express Pipeline. On December 13, 2006, we announced that we had entered into an agreement with Kinder Morgan Energy Partners, L.P. for a 50/50 joint development of MEP. The approximately 500-mile interstate natural gas pipeline, which will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco in Butler, Alabama, will have an initial capacity of 1.4 Bcf per day. Pending necessary regulatory approvals, the approximately $1.3 billion pipeline project is expected to be in service by February 2009. MEP has prearranged binding commitments from multiple shippers for more than 800,000 dekatherms per day which includes a binding commitment from Chesapeake Energy Marketing, Inc., an affiliate of Chesapeake Energy Corporation, for 500,000 dekatherms per day. MEP has executed a firm capacity lease agreement for approximately 280,000 dekatherms per day of capacity on the Oklahoma intrastate pipeline system of Enogex, a subsidiary of OGE Energy, to provide transportation capacity from various locations in Oklahoma into and through MEP. The new pipeline will also interconnect with Natural Gas Pipeline Company of America, a wholly-owned subsidiary of Kinder Morgan, Inc., and with our Texoma pipeline near Paris, Texas.

42-inch Pipeline Project. On March 29, 2007 the Partnership announced the completion of the final phase of its 42-inch pipeline construction project. This final phase connects the Partnership s 36-inch North Texas Pipeline (NTP), the Partnership s Barnett Shale pipeline system, and the Partnership s Bethel Storage Facility to the Carthage Hub and other intrastate and interstate pipelines. This phase completes the previously announced 243 mile 42-inch pipeline project and provides the Partnership and its customers with over 1 Bcf of additional take-away capacity out of the Barnett Shale and Bossier Sands producing areas of Texas.

The completion of the 42-inch pipeline establishes the Partnership as the leader in the intrastate pipeline arena with connections to Texas major marketing hubs including Katy, Waha, Carthage, Houston Ship Channel and Agua Dulce, as well as to the city gates of Texas major cities, including Houston, San Antonio, Austin and Dallas-Ft. Worth. The 42-inch pipeline provides cities, Ship Channel markets, power plants and other consumers throughout the State with significantly greater access to the major producing regions in Texas including the Permian Basin, the Gulf Coast, the Barnett Shale, the Austin Chalk and the Bossier Sands. With this 42-inch completion, the Partnership is capable of providing producers in Texas with unprecedented market flexibility to access both intrastate and interstate pipelines.

The Partnership will begin construction this summer of its next previously announced 42-inch pipeline project, the Southeast Bossier 42-inch Expansion. This project consists of approximately 157 miles of predominately 42-inch pipe connecting the Partnership s 30-inch and 42-inch pipelines with the 30-inch Texoma line north of Beaumont. The Southeast Bossier 42-inch Expansion is expected to be completed by the 1st calendar quarter of 2008.

North Texas Gathering System. In December 2006 we purchased a natural gas gathering system in north Texas for $32 million. The purchase and sale agreement for the gathering system in north Texas also has a contingent payment not to exceed $21 million to be determined two years after the closing date. We will record the required adjustment to the purchase price allocation when the amount of the actual contingent consideration is determinable beyond a reasonable doubt. The gathering system consists of approximately 36 miles of pipeline and has an estimated capacity of 70 MMcf/d. We expect the gathering system will allow us to continue expanding in the Barnett Shale area of north Texas.

Rate Case. 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. On March 9, 2007, Transwestern filed with the FERC its Stipulation and Agreement of Settlement (Stipulation and Agreement) which provides for (i) revised base tariff rates, (ii) the amortization of certain costs, including the Enron Cash Balance Plan, regulatory commission expense, post retirement benefits, the accumulated reserve adjustment regulatory asset, deferred income taxes, and certain non-PCB environmental costs, and (iii) a depreciation rate of 1.20 percent for all transmission plant facilities. On April 27, 2007, the FERC approved the Stipulation and Agreement with an effective date of April 1, 2007. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. In addition, on June 26, 2007, the FERC approved the uncontested February 1, 2007 filed settlement, which settlement fully resolves all the issues set for technical conference by the October 31, 2006 Order, except for the gas quality specifications for Wobbe and Btu.

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Retirement of Officer. On June 11, 2007, ETP and ETE jointly announced that Ray C. Davis, the Co-Chief Executive Officer and Co-Chairman of ETP, and Co-Chairman of ETE will retire from these positions following a transition period to transfer his duties to other members of the management team. Mr. Davis will continue to serve as a director of ETP and ETE. Kelcy L. Warren, currently the Co-Chief Executive Officer and Co-Chairman of ETP and Co-Chairman of ETE, will become the sole Chief Executive Officer and sole Chairman of ETP and the sole Chairman of ETE upon the effective date of Mr. Davis retirement.

Analytical Analysis

The comparability of our condensed consolidated financial statements is affected by our 100% acquisition of Transwestern on December 1, 2006 and our purchases of 50% of CCEH in November 2006 and Titan in June 2006 (see Note 3 to our condensed consolidated financial statements). The comparability is also affected by natural gas prices, mainly in our producer services revenues and natural gas sales on our HPL system. Excluding the impact from volumetric changes, our revenues in these areas are affected by changes in natural gas prices. Since we buy and sell natural gas primarily based on either first of month index prices, gas daily average prices or a combination of both, our revenues tend to be higher when natural gas prices are high and our revenues tend to be lower when natural gas prices are lower. However, a change in natural gas prices is only one of several elements that impact our overall margin. Other factors include, but are not limited to, volumetric changes, our hedging strategies and the use of financial instruments, fee-based revenues, trading activities, and basis differences between market hubs.

The acquisition of Transwestern resulted in a significant increase in our property, plant and equipment, intangible assets and goodwill from August 31, 2006 to May 31, 2007 (see Note 3 to the condensed consolidated financial statements). The increase from August 31, 2006 to May 31, 2007 in our long-term debt was also due to debt assumed in the Transwestern acquisition.

Operating Data

Comparative Results for the Three and Nine Months Ended May 31, 2007 and 2006

Volumes of natural gas sales, NGL sales including propane, and natural gas transported by our midstream, intrastate transportation and storage, interstate transportation, retail propane, and wholesale propane segments are as follows:

Midstream

	Three Months Ended May 31, 2007	Three Months Ended May 31, 2006	Increase (Decrease)	Nine Months Ended May 31, 2007	Nine Months Ended May 31, 2006	Increase (Decrease)
Natural gas MMBtu/d	1,042,641	1,216,424	(173,783)	948,242	1,423,414	(475,172)
NGLs Bbls/d	21,586	10,902	10,684	16,373	10,224	6,149

For the three months ended May 31, 2007, the decrease in natural gas volumes sold was principally due to less favorable market conditions during the fiscal 2007 period resulting in lower sales volumes conducted by our producer services operations. Our NGL sales volumes vary due to our ability to by-pass our processing plants when conditions exist that make it less favorable to process and extract NGLs from our processing plants. The increase in NGL sales volumes is principally due to the completion of our Johnson County processing plants during the 2007 fiscal period and favorable market conditions to process and extract NGLs during the three months ended May 31, 2007 compared to the same period last year.

For the nine months ended May 31, 2007, the decrease in natural gas volumes sold was principally due to less favorable market conditions during the fiscal 2007 period resulting in lower sales volumes conducted by our producer services operations. The increase in NGL sales volumes is principally due to the completion of our Johnson County processing plants in the 2007 fiscal period and favorable market conditions to process and extract NGLs during the 2007 fiscal period compared to the same period last year.

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Intrastate Transportation and Storage

	Three Months Ended May 31, 2007	2006	Increase (Decrease)	Nine Months Ended May 31, 2007	2006	Increase (Decrease)
Natural gas MMBtu/d - transported	6,752,447	4,797,307	1,955,140	5,540,393	4,500,308	1,040,085
Natural gas MMBtu/d - sold	1,204,609	1,303,033	(98,424)	1,388,337	1,572,451	(184,114)

For the three months ended May 31, 2007, transported natural gas volumes increased principally due to our continued efforts to secure long-term shipper contracts and the completion of the 42-inch pipeline project. The 42-inch pipeline was completed in three phases with phase I completed in August 2006, phase II completed in December 2006 and phase III completed in March 2007. We also experienced higher transportation volumes on our Oasis Pipeline during the 2007 period. Natural gas sales volumes on the HPL System for the three months ended May 31, 2007 decreased principally due to less volumes sold to east Texas markets as a result of lower price differentials and due to the new CenterPoint contract that commenced on April 1, 2007. Under the previous contract, we sold and delivered natural gas to CenterPoint for a bundled price. Under the terms of the new agreement, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas capacity in our Bammel storage facility.
For the nine months ended May 31, 2007, transported natural gas volumes increased due to our continued efforts to secure more long-term shipper contracts and the completion of the 42-inch pipeline project. Natural gas sales volumes on the HPL System for the nine months ended May 31, 2007 decreased principally due to less volumes sold to east Texas markets as a result of lower price differentials and due to the new CenterPoint contract that commenced on April 1, 2007.

Interstate Transportation

	Three Months Ended May 31, 2007	2006	Increase	Nine Months Ended May 31, 2007	2006	Increase
Natural gas MMBtu/d - transported	1,802,486		1,802,486	1,765,677		1,765,677
Natural gas MMBtu/d - sold	22,247		22,247	20,382		20,382

The increase was due to the 100% acquisition of Transwestern on December 1, 2006.

Propane

	Three Months Ended May 31, 2007	2006	Increase	Nine Months Ended May 31, 2007	2006	Increase
Propane gallons sold						
(in thousands)						
Retail	127,612	91,514	36,098	521,957	346,010	175,947
Wholesale	23,493	19,299	4,194	79,204	67,143	12,061

Retail Propane. The retail propane operations continue to reflect significant increases in gallons sold in the three and nine months ended May 31, 2007 as compared to the three and nine months ended May 31, 2006 due to the Titan acquisition in June 2006. The combination of below normal degree days, customer conservation, and the slow down of new home construction in our propane markets has contributed to a decrease in expected volumes sold and hindered internal growth. The overall weather in our areas of operations during the three months ended May 31, 2007 was 14.9% warmer than the three months ended May 31, 2006 and 6.5% warmer than normal. Although the sales gallons during the latter part of our fiscal third quarter are less sensitive to the heating degree days, the year-to-date heating degree days have averaged 6.65% below normal which has negatively impacted our expected sales volumes by 8.2%.

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Wholesale Propane. For the three months ended May 31, 2007, sales of wholesale propane gallons increased by 4.2 million gallons compared to the three months ended May 31, 2006. Our wholesale gallons sold through our U.S. operation remained flat while our wholesale gallons sold through our Canadian wholesale operations contributed to the 4.2 million gallon increase.

For the nine months ended May 31, 2007, wholesale propane gallons increased by 12.1 million gallons compared to the same period in 2006. Of this increase, 14.7 million is due to an increase in gallons sold in our Canadian wholesale operations related to increased marketing efforts, offset by a 2.6 million gallon decrease in our U.S. wholesale operations.

Results of Operations

Consolidated Results

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 1,714,786	$ 1,420,335	$ 294,451	$ 5,165,711	$ 6,286,771	$ (1,121,060)
Cost of sales	1,287,387	1,147,367	140,020	3,860,546	5,246,825	(1,386,279)
Gross margin	427,399	272,968	154,431	1,305,165	1,039,946	265,219
Operating expenses	148,903	102,969	45,934	415,093	305,336	109,757
Selling, general and administrative	39,786	23,732	16,054	105,989	79,986	26,003
Depreciation and amortization	47,402	28,149	19,253	126,571	84,076	42,495
Consolidated operating income	191,308	118,118	73,190	657,512	570,548	86,964
Interest expense	(46,149)	(13,674)	(32,475)	(128,383)	(70,609)	(57,774)
Equity in earnings (losses) of affiliates	839	(150)	989	5,212	(318)	5,530
Gain (loss) on disposal of assets	(2,500)	22	(2,522)	(3,785)	556	(4,341)
Interest and other income, net	17,751	9,672	8,079	20,845	12,933	7,912
Income tax expense	(3,560)	(1,981)	(1,579)	(10,456)	(28,406)	17,950
Minority interests	(223)	(95)	(128)	(1,333)	(2,199)	866
Net income	$ 157,466	$ 111,912	$ 45,554	$ 539,612	$ 482,505	$ 57,107

See the detailed discussion of revenues, costs of sales, margin and operating expense by operating segment below.

Interest Expense. Of the increase in interest expense for the three months ended May 31, 2007 compared to the three months ended May 31, 2006, $21.2 million related to increased borrowings on the Partnership s Senior Notes and Revolving Credit Facility. Borrowings increased primarily due to the financing of our growth capital expenditures and the CCEH and Titan acquisitions. Debt assumed in the Transwestern acquisition resulted in $2.0 million of increased interest expense during the three months ended May 31, 2007. During the three months ended May 31, 2006, gains of $9.3 million related to interest rate swaps were recorded as a reduction to interest expense. Such gains were not recognized in interest expense in the three months ended May 31, 2007; rather, such gains are included in other income in fiscal 2007. Interest expense also increased due to $1.4 million of hedge ineffectiveness charges during fiscal 2007. The increase was partially offset by propane related interest which decreased $1.5 million due primarily to the scheduled debt payments that have occurred between the three month periods.

The increase in interest expense for the nine months ended May 31, 2007 compared to the nine months ended May 31, 2006, was principally due to a net $42.7 million increase in interest expense related to increased borrowings on the Partnership s Senior Notes and Revolving Credit Facility and the effect of the May 31, 2006 gains of $9.2 million on interest rate swaps, as described above. Debt assumed in the Transwestern acquisition represents $7.1 million of the increased interest expense. Hedge ineffectiveness charges increased interest expense by $1.8 million in fiscal 2007, compared to gains of $0.8 million in fiscal 2006. Propane related interest decreased $3.7 million due primarily to the scheduled debt payments that have occurred between the nine month periods.

Equity in Earnings of Affiliates. The increase in equity in earnings of affiliates for the nine months ended May 31, 2007 compared to the nine months ended May 31, 2006 was due primarily to $5.1 million of equity income from our 50% ownership of CCEH for the month of November

2006. We did not have an investment in CCEH last year. We redeemed our investment in CCEH in connection with our Transwestern acquisition.

Gain (Loss) on Disposal of Assets. The loss on disposal of assets reflected in the three months ended May 31, 2007 was principally due to losses resulting from the sale of a compressor station.

Interest and Other Income, net. The increase in interest and other income in the three and nine month periods ended May 31, 2007 is due primarily to gains on interest rate swaps that are not accounted for as hedges. Such gains were included in interest expense in fiscal 2006.

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Income Tax Expense. As a partnership, we are not subject to income taxes. However, certain wholly-owned subsidiaries are corporations that are subject to income taxes. The increase in income tax expense for the three months ended May 31, 2007 was primarily related to the Texas margin tax that was not effective until January 1, 2007. The decreased expense for the nine months ended May 31, 2007 was attributed principally to higher income from trading gains recognized by a taxable subsidiary during the periods ended May 31, 2006, than was realized by such subsidiary in the current periods. The decrease was partially offset by the Texas margin tax in the period subsequent to January 1, 2007.

Three and Nine Month Operating Results by Segment

Midstream

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 869,079	$ 789,966	$ 79,113	$ 2,101,507	$ 3,544,821	$ (1,443,314)
Cost of sales	812,815	745,162	67,653	1,945,245	3,342,588	(1,397,343)
Gross margin	56,264	44,804	11,460	156,262	202,233	(45,971)
Operating expenses	10,797	8,089	2,708	28,590	22,431	6,159
Selling, general and administrative	9,069	5,444	3,625	24,472	20,101	4,371
Depreciation and amortization	6,226	4,046	2,180	16,410	11,612	4,798
Segment operating income	$ 30,172	$ 27,225	$ 2,947	$ 86,790	$ 148,089	$ (61,299)

Gross Margin. For the three months ended May 31, 2007, midstream s gross margin increased $11.5 million as a result of the following factors:

- Increase in processing margin and fee-based revenue from our gathering assets. The increase was due to incremental volumes from the completion of our Johnson County plant in the first quarter of 2007, the acquisition of three natural gas gathering systems during the first six months of the 2007 fiscal year, and favorable processing conditions during the third fiscal quarter of 2007 compared to the same period last year at our Southeast Texas processing plant.

- Increase in non-trading margin from our marketing activities of $4.2 million. Despite lower volumes by our producer services operations, margins were higher due to more favorable market conditions in the three months ended May 31, 2007 compared to the same period last year.

- Decrease in net trading revenues of $8.1 million principally due to less favorable results on positions entered into during the three months ended May 31, 2007 compared to the same period last year.

For the nine months ended May 31, 2007, midstream s gross margin decreased by $46.0 million primarily due to the following factors:

- Decrease in net trading revenues of $56.7 million. During the fiscal 2006 period, we recognized trading gains resulting from market anomalies created by the hurricanes that struck the Texas and Louisiana coasts in August and September 2005. There were no significant weather anomalies during the nine months ended May 31, 2007.

- Decrease in non-trading margin from our marketing activities of $25.9 million. Market conditions, including lower basis differentials between the west and east Texas markets, resulted in lower sales volumes conducted by our producer services operations.

- Increase in processing margin and fee-based revenue. The increase was due to the completion of our Johnson County plant in the first quarter of 2007, the acquisition of three gathering systems during the fiscal 2007 period, and favorable processing conditions during the fiscal 2007 period compared to the same period last year at our Southeast Texas processing plant.

Operating Expenses. Midstream operating expenses increased $2.7 million for the three months ended May 31, 2007 compared to the same period ended May 31, 2006. The increase was primarily driven by increased compressor rentals of $1.1 million, increased pipeline and compressor maintenance of $0.8 million, and increased electricity costs of $0.5 million. The increases were primarily driven by the Johnson County plant addition and the acquisition of three gathering systems during the first six months of the fiscal 2007 period.

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Midstream operating expenses increased $6.2 million for the nine months ended May 31, 2007 compared to the same period ended May 31, 2006. The increase was primarily driven by increased compressor rental expense of $2.7 million, increased pipeline and compressor maintenance of $1.8 million and increased employee-related costs, such as salaries, incentive compensation and healthcare costs, of $1.2 million. The increases were primarily driven by the Johnson County plant addition and the acquisition of three gathering systems during the first six months of the fiscal 2007 period.

Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses for the three months ended May 31, 2007 increased $3.6 million compared to the three months ended May 31, 2006. The increase was attributable to $3.8 million of legal costs associated with the regulatory inquiries. There also was a $4.9 million increase in employee-related costs such as salaries, incentive compensation and healthcare costs. These increases were offset by a $0.5 million increase in overhead costs capitalized to capital expansion projects and a $4.8 million decrease due to more corporate overhead being allocated to the transportation segment. The allocation of departmental costs is based on factors such as headcount, number of meters, payroll, margin and on-going projects and is intended to fairly present the segment s operating results.

Midstream general and administrative expenses for the nine months ended May 31, 2007 increased $4.4 million compared to the nine months ended May 31, 2006. The increase was attributable to $8.6 million of legal costs associated with regulatory inquiries, a $1.9 million allocation of administrative expenses for overhead costs which previously had not been allocated, and increases of $6.1 million in employee-related costs such as salaries, incentive compensation and healthcare costs. The increase was offset by increases of $6.7 million in departmental costs allocated to the transportation and storage operating segment, an increase of $1.8 million in overhead costs capitalized to capital expansion projects, and a one-time $0.9 million reimbursement of administrative costs related to the North Side Loop pipeline project from the project partner.

Depreciation and Amortization. Midstream depreciation and amortization expense increased $2.2 million for the three months ended May 31, 2007 compared to the same three month period in 2006 principally due to plant and equipment placed into service subsequent to May 31, 2006, the completion of our Johnson County plant in the first fiscal quarter of 2007, and the acquisitions of three gathering systems in the first and second fiscal quarters of 2007.

The increase of $4.8 million for the nine months ended May 31, 2007 compared to the same nine month period in 2006 is principally due to plant and equipment placed into service subsequent to May 31, 2006, the completion of our Johnson County plant in the first fiscal quarter of 2007, and the acquisitions of three gathering systems in the first and second fiscal quarters of 2007.

Intrastate Transportation and Storage

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 963,993	$ 919,390	$ 44,603	$ 2,882,901	$ 3,975,164	$ (1,092,263)
Cost of sales	770,413	773,337	(2,924)	2,314,887	3,439,125	(1,124,238)
Gross margin	193,580	146,053	47,527	568,014	536,039	31,975
Operating expenses	49,358	43,445	5,913	129,497	131,694	(2,197)
Selling, general and administrative	15,345	10,415	4,930	40,716	33,926	6,790
Depreciation and amortization	14,467	10,334	4,133	38,776	31,130	7,646
Segment operating income	$ 114,410	$ 81,859	$ 32,551	$ 359,025	$ 339,289	$ 19,736

Gross Margin. For the three months ended May 31, 2007 as compared to three months ended May 31, 2006, intrastate transportation and storage gross margin increased by $47.5 million, principally due to the net effect of the following:

- Volumes. Overall volumes on our transportation pipelines were higher during the third fiscal quarter compared to the same period last year due to the completion of the final phase of the 42-inch pipeline in March 2007, continued efforts to secure long-term shipper contracts, and the completion of various growth projects during 2007.

- Higher natural gas prices. Excluding the impact of volumetric changes, our fuel retention fees are directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and decreases in natural gas prices tend to decrease our fuel retention fees. Our average natural gas prices for retained fuel increased from a range of $5.00 to $6.00/MMBtu during the three months ended May 31, 2006 to $6.00 to $7.00/MMBtu during the same period this year.

- Increase in storage margin. The increase was due to the recognition of gains from the discontinuation of hedge accounting resulting from our determination that originally forecasted sales of natural gas from the Partnership s Bammel storage facility were no longer probable to occur by the specified time period, or within an additional two-month time period thereafter. As a result, we recognized previously deferred unrealized gains of approximately $19.3 million during the three months ended May 31, 2007. There were no such gains recognized during the three months ended May 31, 2006.

- We recognized revenue of $10.8 million and $14.7 million during the three months ended May 31, 2007 and 2006, respectively, related to a transportation contract with a major customer on our ET Fuel System. In connection with our acquisition of the ET Fuel System in June 2004, we entered into an eight year transportation agreement with TXU Portfolio Management Company, LP (TXU Shipper) to transport a minimum of 115,600 MMBtu per year, reduced to 100,000 MMBtu per year beginning in January 2006. As of May 31, 2007 and 2006, respectively, we were entitled to receive additional fees for the difference between actual volumes transported by TXU Shipper on the ET Fuel System and the minimum amount as stated above during the twelve-month period ended May 31, 2007 and 2006.

For the nine months ended May 31, 2007 as compared to the nine months ended May 31, 2006, intrastate transportation and storage gross margin increased by $32.0 million, principally due to the net effect of the following:

- Volumes. Overall volumes on our transportation pipelines were higher during the 2007 fiscal period compared to the same period last year due to the completion of the 42-inch pipeline, continued efforts to secure long-term shipper contracts, and a colder winter in fiscal 2007.

- Lower natural gas prices. Excluding the impact of volumetric changes, our fuel retention fees are directly impacted by changes in natural gas prices. Increases in natural gas prices tend to increase our fuel retention fees and decreases in natural gas prices tend to decrease our fuel retention fees. Our average natural gas prices for retained fuel decreased from a range of $7.00 to $12.00/MMBtu during the nine months ended May 31, 2006 to $4.00 to $7.00/MMBtu during the same period this year resulting in lower revenue by $36.0 million.

- Increase in storage margin of $53.9 million. The increase was due to $31.4 million recognized on 7.5 Bcf more volume withdrawn from our Bammel storage facility than in 2006 and a significant loss on settled derivatives during the fiscal 2006 period. These increases were offset by a $47.5 million decrease in gains from the discontinuation of hedge accounting and approximately $18.0 million in margin on gas sold from our Bammel facility and delivered to a customer in September 2005. There were no similar sales during the nine months ended May 31, 2007.

- Decrease in margin of $21.7 million related to well head volumes. As discussed above, we purchase natural gas from producers at a discount to a specified price and resell to customers at an index price. We experienced lower volumes and lower natural gas prices during the nine months ended May 31, 2007 compared to the same period last year.

Operating Expenses. Intrastate transportation and storage operating expenses increased $5.9 million when comparing the three months ended May 31, 2007 to the corresponding three month period in 2006. The increase was primarily attributable to an increase of $4.7 million in compressor and pipeline maintenance and $1.3 million in electric utilities costs. These increases are due to ongoing pipeline integrity projects as well as increased compression requirements due to the growth of the transportation assets.

Intrastate transportation and storage operating expenses decreased $2.2 million when comparing the nine months ended May 31, 2007 to the same prior period ended May 31, 2006. The decrease was principally attributable to a decrease of $18.6 million in fuel consumption offset by increases of $10.7 million in pipeline and compressor maintenance and compressor rentals, $3.9 million in property taxes, and $1.6 million in employee-related costs such as salaries, incentive compensation and healthcare costs.

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Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased $4.9 million for the three months ended May 31, 2007 compared to the three months ended May 31, 2006 principally due to an increase in certain departmental costs allocated from the midstream segment. The increase in allocated departmental costs is primarily due to the significance of the operations added to the intrastate transportation segment from the various construction projects completed.

Intrastate transportation and storage general and administrative expenses increased $6.8 million for the nine months ended May 31, 2007 compared to the nine months ended May 31, 2006 principally due to an increase in certain departmental costs allocated from the midstream segment. The increase in allocated departmental costs is primarily due to the significance of the operations added to the intrastate transportation segment from the various construction projects.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased $4.1 million for the three months ended May 31, 2007 compared to the three months ended May 31, 2006, principally due to plant and equipment placed into service subsequent to May 31, 2006.

Intrastate transportation and storage depreciation and amortization expense increased $7.6 million from the nine months ended May 31, 2006 to the nine months ended May 31, 2007. The increase was principally due to plant and equipment placed into service subsequent to May 31, 2006 offset by $1.1 million of depreciation expense recorded in the second fiscal quarter of 2006 for a purchase price allocation related to HPL.

Interstate Transportation

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 61,714	$	$ 61,714	$ 119,872	$	$ 119,872
Operating expenses	13,159		13,159	21,680		21,680
Selling, general and administrative	5,525		5,525	11,396		11,396
Depreciation and amortization	9,241		9,241	18,895		18,895
Segment operating income	$ 33,789	$	$ 33,789	$ 67,901	$	$ 67,901

The increase in all categories was due to the acquisition of 100% of Transwestern on December 1, 2006.

Retail Propane

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Retail propane revenues	$ 252,584	$ 168,767	$ 83,817	$ 1,017,926	$ 643,187	$ 374,739
Other propane related revenues	23,861	16,505	7,356	83,313	56,263	27,050
Retail propane cost of sales	158,167	101,889	56,278	630,420	392,950	237,470
Other propane related cost of sales	5,333	4,264	1,069	19,794	15,517	4,277
Gross margin	112,945	79,119	33,826	451,025	290,983	160,042
Operating expenses	74,425	48,957	25,468	230,759	145,043	85,716
Selling, general and administrative	8,148	3,664	4,484	23,194	11,753	11,441
Depreciation and amortization	17,306	13,491	3,815	51,835	40,445	11,390
Segment operating income	$ 13,066	$ 13,007	$ 59	$ 145,237	$ 93,742	$ 51,495

Revenues. Retail fuel revenues for the three and nine months ended May 31, 2007 mainly increased in relation to the increased volumes from the Titan acquisition described above and, to a lesser extent, other propane acquisitions and higher selling prices over the same period last year. Other propane related revenues increased $7.4 million and $27.1 million for the three and nine months ended May 31, 2007, respectively as compared to the same periods for fiscal 2006 due to the Titan acquisition in June, 2006 and other propane acquisitions and enhanced fee generating programs in servicing customers.

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Costs of Sales. During the three and nine months ended May 31, 2007 compared to the three and nine months ended May 31, 2006, retail propane cost of sales increased by $56.3 million and $237.5 million, respectively, which is mainly the result of an overall increase in cost of sales related to the gallons sold by customer service locations added through the Titan acquisition. Cost of sales also increased in relation to other increased volumes as described above, and, to a lesser extent, increases in the cost of fuel for the three and nine month periods ended May 31, 2007 as compared to the same periods for May 31, 2006.

Gross Margin. The overall increase in gross margin for the three and nine-month comparable periods ended May 31, 2007 and 2006 is primarily related to the Titan acquisition in June 2006. The propane margin remained strong during the three and nine months ended May 31, 2007 during the periods of warmer weather and higher fuel prices. Optimization of the margins is influenced by market opportunities, independent competitors and concerns for long term retention of customers.

Operating Expenses. During the three and nine months ended May 31, 2007, operating expenses increased by $25.5 million and $85.7 million, respectively, compared to the same three and nine-month periods last year. These increases were mainly due to a $21.3 million and $67.1 million increase for the three and nine months ended May 31, 2007, respectively, directly due to the identifiable Titan operations. Other increases in operating expenses relate to higher vehicle fuel costs and other vehicle expenses, and general increases in other operating expenses including safety training costs of the newly acquired employees from the Titan acquisition, and other acquisition costs related to blends and mergers of propane locations to gain forward synergies and cost savings.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses for the comparable three and nine-month periods of May 31, 2007 and 2006 is primarily due to increases from administrative expense allocations, increases in administrative bonuses, salaries and deferred compensation expense related to increases in staffing and additional restricted unit awards outstanding and the addition of administrative employees from the Titan acquisition. The increase also includes increases in our IT costs as we continue to enhance our current infrastructure for our administrative and propane systems. Effective with the Transwestern acquisition in December 2006, an allocation of administrative expenses is now made to the operating partnerships, which increased the retail propane selling, general and administrative expenses by $2.2 million and $4.7 million for the three and nine months ended May 31, 2007, respectively.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense for the three and nine months ended May 31, 2007 as compared to 2006 is due primarily to the acquisition of Titan on June 1, 2006.

Wholesale Propane

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 30,746	$ 21,461	$ 9,285	$ 98,992	$ 78,361	$ 20,631
Cost of sales	28,847	19,959	8,888	92,072	71,671	20,401
Gross margin	1,899	1,502	397	6,920	6,690	230
Operating expenses	819	1,265	(446)	2,645	2,868	(223)
Selling, general and administrative	608	506	102	1,890	1,478	412
Depreciation and amortization	162	173	(11)	530	579	(49)
Segment operating income (loss)	$ 310	$ (442)	$ 752	$ 1,855	$ 1,765	$ 90

Revenues. Of the $9.3 million increase in wholesale revenue for the three months ended May 31, 2007 compared to the same three months in 2006, $8.7 million is related to the increase in gallons sold to new customers of our Canadian operations and the increased selling prices in that area.

Of the increase of $20.6 million in wholesale revenue from the nine months ended May 31, 2007 compared to the same nine-month period last year, $23.9 million is related to the increase in gallons sold to new customers of our Canadian operations and the increased selling prices in that area, offset by a decrease of $3.3 million in our U.S. wholesale operations.

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Costs of Sales. For the three and nine months ended May 31, 2007 compared to the corresponding three and nine months ended May 31, 2006, total cost of sales increased by $8.9 million and $20.4 million, respectively. Foreign wholesale cost of sales increased $8.3 million and $22.3 million for the three and nine months ended May 31, 2007 due to the increased volumes sold and to a lesser extent due to the increase in fuel cost per gallon sold. U.S. wholesale cost of sales increased $0.6 million and decreased $1.9 million for the three and nine months ended May 31, 2007 as compared to the three and nine months ended May 31, 2006.

Gross Margin. The overall gross margin in the wholesale operations for the three and nine months ended May 31, 2007 as compared to the three and nine months ended May 31, 2006 remained effectively unchanged. Wholesale operations normally are a low margin segment in which increases in the cost of fuel cannot always be passed to a customer due to predetermined sales contracts.

Other

	Three Months Ended May 31,			Nine Months Ended May 31,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 997	$ 2,053	$ (1,056)	$ 3,600	$ 5,575	$ (1,975)
Cost of sales		563	(563)	528	1,574	(1,046)
Operating expenses	345	1,213	(868)	1,922	3,300	(1,378)
Depreciation and amortization		105	(105)	125	310	(185)
Other operating income	$ 652	$ 172	$ 480	$ 1,025	$ 391	$ 634
Unallocated selling, general and administrative expenses	$ 1,091	$ 3,703	$ (2,612)	$ 4,321	$ 12,728	$ (8,407)

Unallocated Selling, General and Administrative Expenses. Selling, general and administrative expenses that relate to the administration and general operations of the Partnership were, prior to December 2006, not allocated to our segments. In conjunction with the Transwestern acquisition, selling, general and administrative expenses are now allocated to the operating partnerships. For the three and nine months ended May 31, 2007, a net $4.7 million and $10.3 million was allocated to the operating partnerships, which constituted the decrease in total unallocated selling general and administrative expenses from the three and nine-month periods ended May 31, 2006. The decrease in the unallocated selling, general and administrative expenses due to the allocations now in place to the operating partnerships, is offset by increases in expenses primarily related to management incentive plans.

Income Taxes

As a Partnership we generally are not subject to income tax. We are, however, subject to a statutory requirement that our non-qualifying income (including income such as derivative gains from trading activities, service income, tank rentals and others) cannot exceed 10% of our total gross income, determined on a calendar year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualified income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the three and nine months ended May 31, 2007 and 2006, our non-qualifying income was not expected to, or did not, exceed the statutory limit.

The difference between the statutory rate and the effective rate is summarized as follows:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Federal statutory tax rate	35.0%	35.0%	35.0%	35.0%
State income tax rate net of federal benefit	2.1%	2.9%	1.1%	3.1%
Earnings not subject to tax at the Partnership level	(34.9%)	(36.2%)	(34.2%)	(32.6%)

Effective tax rate	2.2%	1.7%	1.9%	5.5%

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Income tax expense consists of the following current and deferred amounts:

	Three Months Ended May 31,		Nine Months Ended May 31,	
	2007	2006	2007	2006
Current provision (benefit):				
Federal	$ 492	$ (2,111)	$ 6,979	$ 26,006
State	3,462	479	6,288	1,767
	3,954	(1,632)	13,267	27,773
Deferred provision (benefit):				
Federal	(394)	3,603	(2,572)	978
State		10	(239)	(345)
	(394)	3,613	(2,811)	633
Total	$ 3,560	$ 1,981	$ 10,456	$ 28,406

We do not expect our tax payments in any year to differ significantly from our current tax provisions.

A consolidated subsidiary acquired in the Titan acquisition has net operating loss carry forwards of approximately $13.0 million, which carry forwards expire at varying times through December 31, 2026. We established a deferred tax asset of approximately $4.0 million in the Titan purchase price allocation for loss carry forwards as of the date of acquisition.

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the three and nine months ended May 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $2.8 million and $4.7 million, respectively. There is no comparable state tax expense for the periods ended May 31, 2006.

Liquidity and Capital Resources

Our ability to satisfy our obligations and pay distributions to our partners 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.

Future capital requirements will generally consist of:

maintenance capital expenditures, which include capital expenditures made to connect additional wells to our natural gas systems in order to maintain or increase throughput on existing assets for which we expect to expend approximately $21.4 million for the remainder of the fiscal year and capital expenditures to extend the useful lives of our propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet, for which we expect to expend approximately $5.0 million for the remainder of the fiscal year;

growth capital expenditures, mainly for constructing new pipelines, processing plants and treating plants for which we expect to expend approximately $380.4 million for the remainder of the fiscal year, including $141.3 million related to Transwestern; and customer propane tanks for which we expect to expend approximately $3.0 million for the remainder of the fiscal year; and acquisition capital expenditures including acquisition of new pipeline systems and propane operations.

We believe that cash generated from the operations of our businesses will be sufficient to meet anticipated maintenance capital expenditures. We will initially finance all capital requirements by cash flows from operating activities. To the extent that our future capital requirements exceed cash flows from operating activities:

maintenance capital expenditures may be financed by the proceeds of borrowings under the existing credit facilities described below, which will be repaid by subsequent seasonal reductions in inventory and accounts receivable;

growth capital expenditures may be financed by the proceeds of borrowings under the existing credit facilities and the issuance of additional Common Units or a combination thereof; and

acquisition capital expenditures may be financed by the proceeds of borrowings under the existing credit facilities, other lines of credit, long-term debt, the issuance of additional Common Units or a combination thereof.

On October 3, 2006, we entered into long-term agreements with CenterPoint Energy Resources Corp. (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region commencing on April 1, 2007. These agreements replace a previous agreement with CenterPoint. Under the terms of the new agreements, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas storage capacity in our Bammel Storage facility. Under the new agreements with CenterPoint, we will no longer need to utilize predominately all of the Bammel Storage facility s working gas capacity for supplying CenterPoint s winter needs. This may reduce our working capital requirements that were necessary to finance the working gas while in storage and may provide us an opportunity to offer storage to third parties.

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 level of success in integrating our acquisitions, including the recently acquired Transwestern and Titan operations, and other factors.

Operating Activities. Cash provided by operating activities during the nine months ended May 31, 2007, was $869.3 million as compared to cash provided by operating activities of $527.8 million for the nine months ended May 31, 2006. The net cash provided by operations for the nine months ended May 31, 2007 consisted of net income of $539.6 million, non-cash charges of $139.6 million, principally depreciation and amortization, unit based compensation expense, and deferred taxes, and cash from changes in operating assets and liabilities of $190.1 million. Various components of operating assets and liabilities changed significantly from the prior period due to factors such as the variance in the timing of accounts receivable collections, payments on accounts payable, and the timing of the purchase and sale of inventories related to the propane and intrastate transportation and storage operations.

Investing Activities. Cash used in investing activities during the nine months ended May 31, 2007 of $1.9 billion is comprised primarily of cash paid for our investment in CCEH of $1.0 billion (net of the receipt of $49.0 million from CCEH as per the terms of our acquisition agreement), other acquisitions of $87.5 million and $736.8 million invested for growth capital expenditures (including the payment of $35.9 million accrued in prior periods) of which $711.8 million related to midstream and transportation assets and $25.0 million to propane assets. We also incurred $62.4 million in maintenance expenditures needed to sustain operations of which $42.5 million related to midstream and transportation assets and $19.9 million to propane assets.

Financing Activities. Cash provided by financing activities was $1.1 billion for the nine months ended May 31, 2007. We received $1.2 billion in proceeds from the sale of Class G Units to ETE and our General Partner contributed $24.5 million to maintain its two percent ownership in us. We used $1.0 billion of the proceeds to fund the purchase of the member interests of CCEH and the remainder was used to repay the indebtedness we incurred in connection with the Titan acquisition as discussed above in Note 3 to our condensed consolidated financial statements. On October 23, 2006, we received net proceeds of $791.0 million from the issuance of senior notes (see Note 13 to our condensed consolidated financial statements above) which we used to repay borrowings under the Partnership s revolving credit facility. In January and February 2007, we borrowed a total of approximately $307.0 million on our Revolving Credit Facility to fund required pre-payments of the debt we assumed in connection with our acquisition of Transwestern. In May 2007, Transwestern issued $307.0 million principal of Senior Unsecured Series Notes which we used $295.0 million to repay borrowings and accrued interest outstanding under the Partnership s revolving credit facility and $12.0 million for general partnership purposes. During the nine months ended May 31, 2007, we paid distributions of $451.8 million to our partners.

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Financing and Sources of Liquidity

On October 23, 2006, we closed the issuance, under our $1.5 billion S-3 Registration Statement, of $400.0 million of 6.125% senior notes due 2017 and $400.0 million of 6.625% senior notes due 2036. We used the net proceeds of approximately $791.0 million from the issuance of the Notes to repay borrowings and accrued interest outstanding under our Revolving Credit Facility, to pay expenses associated with the offering and for general partnership purposes. Interest on the 2017 senior notes is payable semiannually on February 15 and August 15 of each year, beginning February 15, 2007, and interest on the 2036 senior notes is payable semiannually on April 15 and October 15 of each year, beginning April 15, 2007. All of the Partnership s obligations under the Notes are fully and unconditionally guaranteed by ETC OLP and Titan and substantially all of their present and future wholly-owned subsidiaries.

During fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1.0 billion aggregate offering price of Common Units representing our Limited Partner interests. Through May 31, 2007, we have not made any sales under this Registration Statement.

Description of Indebtedness

Energy Transfer Partners Facilities

Our indebtedness as of May 31, 2007 consists of $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012, $400.0 million in principal amount of 6.125% Senior Notes due 2017, $400.0 million in principal amount of 6.625% Senior Notes due 2036 and a Revolving Credit Facility that allows for borrowings of up to $1.5 billion available through June 29, 2011. We also currently maintain separate credit facilities for HOLP. The terms of our indebtedness and our Operating Partnerships are described in more detail in our Annual Report on Form 10-K for fiscal 2006 filed with the Securities and Exchange Commission on November 13, 2006.

We have a $1.5 billion Amended and Restated Revolving Credit Facility (the ETP Revolving Credit Facility) available through June 29, 2011. Amounts borrowed under the ETP Revolving Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. There is also a Swingline loan option with a maximum borrowing of $75.0 million at a daily rate based on LIBOR. The commitment fee payable on the unused portion of the facility varies based on our credit rating with a maximum fee of 0.175%. As of May 31, 2007, there was a balance of $735.1 million in revolving credit loans (including $68.1 million in Swingline loans) and $57.3 million in letters of credit. The weighted average interest rate on the total amount outstanding at May 31, 2007, was 5.994%. The total amount available under the ETP Revolving Credit Facility as of May 31, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $707.6 million. The ETP Revolving Credit Facility is fully and unconditionally guaranteed by ETC OLP and Titan and all of their direct and indirect wholly-owned subsidiaries. The ETP Revolving Credit Facility is unsecured and has equal rights to holders of our other current and future unsecured debt.

On October 18, 2006 we paid and retired a $250.0 million unsecured Revolving Credit Facility which matured under its terms on December 1, 2006. Amounts borrowed under this facility bore interest at a rate based on either a Eurodollar rate or a base rate. The maximum commitment fee payable on the unused portion of the facility was 0.25%. The $250.0 million Revolving Credit Facility was fully and unconditionally guaranteed by ETC OLP and all of the direct and indirect wholly-owned subsidiaries of ETC OLP.

Transwestern Debt

Long-term debt as of December 1, 2006 we assumed in connection with the Transwestern acquisition is as follows:

5.39% Notes due November 17, 2014	$ 270,000
5.54% Notes due November 17, 2016	250,000
Total long-term debt outstanding	520,000
Unamortized debt discount	(623)
Total long-term debt assumed	$ 519,377

No principal payments are required under any of the debt agreements prior to their respective maturity dates. However, in connection with our acquisition of Transwestern, due to a change in control provision in

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Transwestern s debt agreements, Transwestern was required to pre-pay approximately $307.0 million of long-term debt, $292.0 million in February 2007 and $15.0 million in March 2007. These payments were financed with borrowings from ETP s Revolving Credit Facility.

In May 2007, Transwestern issued a total of $307 million aggregate principal amount of Senior Unsecured Series Notes (Unsecured Series Notes) comprised of the following:

Principal	Interest Rate	Maturity Date
$ 82,000	5.64%	May 24, 2017
150,000	5.89%	May 24, 2022
75,000	6.16%	May 24, 2037

The Partnership used $295.0 million of the proceeds received to repay borrowings and accrued interest outstanding under the ETP Revolving Credit Facility and $12.0 million for general partnership purposes. Interest is payable semi-annually, and the Unsecured Series Notes rank pari passu with Transwestern s other unsecured debt. The Unsecured Series Notes are prepayable at any time in whole or pro rata in part, subject to a premium or upon a change of control event, as defined.

Transwestern s credit agreements contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets and the payment of dividends and require certain debt to capitalization ratios.

HOLP Facilities

A $75.0 million Senior Revolving Facility (the HOLP Facility) is available through June 30, 2011. The HOLP Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the agreement related to the HOLP Facility, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility. As of May 31, 2007, there was no balance outstanding on the revolving credit loans. A Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Facility. There were outstanding Letters of Credit of $1.0 million at May 31, 2007. The sum of the loans made under the HOLP Facility plus the Letter of Credit Exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Facility. The amount available under the HOLP Facility at May 31, 2007 was $74.0 million.

We were in compliance with all of the covenants of our debt agreements as of May 31, 2007.

Cash Distributions

We will use our cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders as well as to our General Partner in respect of its 2% general partner interest and its incentive distribution rights. Under the Partnership Agreement, we will distribute to our partners within 45 days after the end of each fiscal quarter, an amount equal to all of our Available Cash 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.

On October 16, 2006, we paid a quarterly distribution of $0.75 per Common Unit ($3.00 per unit on an annualized basis) to Unitholders of record at the close of business on October 5, 2006. On January 15, 2007, we paid a quarterly distribution of $0.7688 per limited partner unit ($3.075 per unit on an annualized basis) to Unitholders of record at the close of business on January 4, 2007. On April 13, 2007, we paid a quarterly distribution of $0.7875 ($3.15 per unit on an annualized basis) to Unitholders of record at the close of business on April 6, 2007. On June 20, 2007, we declared a per unit cash distribution of $0.80625 ($3.225 per unit on an annualized basis) for the quarter ended May 31, 2007, which will be paid on July 16, 2007 to Unitholders of record at the close of business on July 2, 2007.

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On October 16, 2006, we paid a quarterly distribution of $42.6 million in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. On January 15, 2007, we paid a quarterly distribution of $55.2 million in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. On April 13, 2007, we paid a quarterly distribution of $57.7 million in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. On July 16, 2007, we will pay a quarterly distribution of $60.3 million in the aggregate in respect of our General Partner s 2% general partner interest and its incentive distribution rights. Our General Partner s incentive distributions rights entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis). These incentive distributions entitle our General Partner to increasing percentages of our cash distributions based upon exceeding incentive distribution thresholds specified in our Partnership Agreement, which incentive distribution rights entitle our General Partner to receive 50% of our cash distributions in excess of $0.4125 per unit. At current distribution levels, our General Partner is entitled to receive cash distributions at the highest incentive distribution level of 50% with respect to our distributions in excess of $0.4125 per unit.

Contractual Obligations

Total payments due for the remainder of fiscal year 2007 increased due to the Transwestern acquisition as we assumed additional operating lease obligations. This increase was approximately $3.4 million resulting in a total obligation of approximately $12.2 million.

New Accounting Standards

See Note 2 to our condensed consolidated financial statements.

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 August 31, 2006, in addition to the interim unaudited condensed 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.

The following table provides a summary of our commodity-related price risk management assets and liabilities as of May 31, 2007:

May 31, 2007	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	19,169,697	2007-2009	$ 7,746
Swing Swaps IFERC	Gas	(4,942,500)	2007-2008	365
Fixed Swaps/Futures	Gas	(9,867,500)	2007-2009	(1,705)
Forward Physical Contracts	Gas	(12,584,549)	2007-2008	128
Options	Gas	(1,038,000)	2007-2008	(176)
Propane Swaps - in Gallons	Propane	882,000	2007-2008	12
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,747,500	2007-2008	$ 2,666
Swing Swaps IFERC	Gas	3,300,000	2007	(249)
Forward Physical Contracts	Gas		2007	(352)
Fixed Swaps/Futures	Gas	(300,000)	2007	21
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	(21,407,500)	2007-2009	$ (291)
Fixed Swaps/Futures	Gas	(22,332,500)	2007-2009	(1,918)

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Credit Risk

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

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact 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. Based on our policies, exposures, credit and other reserves, management does not anticipate a material adverse effect on financial position or results of operations as a result of counterparty performance.

Sensitivity Analysis

The table below summarizes our commodity-related financial derivative instruments and fair values as of May 31, 2007. It also assumes a hypothetical 10% change in the underlying price of the commodity and its effect.

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Fixed Swaps/Futures	(32,200,000)	$ (3,623)	$ 27,440
Basis Swaps IFERC/NYMEX	(2,237,803)	7,455	750
Swing Swaps IFERC	(4,942,500)	365	605
Options	(1,038,000)	(176)	77
Forward Physical Contracts	(12,584,549)	128	2,344
Propane Forwards/Swaps (in Gallons)	882,000	12	19
Trading Derivatives			
Fixed Swaps/Futures	(300,000)	21	228
Swing Swaps IFERC	3,300,000	(249)	22
Basic Swaps IFERC/NYMEX	2,747,500	2,666	126
Forward Physical Contracts		(352)	2,269

The fair values of the commodity-related financial positions have been determined using independent third party prices, readily available market information, broker quotes 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 percent 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 our consolidated results of operations or in accumulated other comprehensive income. In the event of an actual 10 percent change in prompt month natural gas prices, the fair value of our total derivative portfolio may not change by 10 percent 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

We are exposed to market risk for changes in interest rates related to our bank credit facilities. We manage a portion of our interest rate exposures by utilizing interest rate swaps and similar arrangements which allow us to effectively convert a portion of variable rate debt into fixed rate debt.

In connection with the Titan acquisition, we assumed a three year LIBOR interest rate swap with a notional amount of $125.0 million. The fair value of this swap as of May 31, 2007 and August 31, 2006 was a net asset of $0.2 million and $0.5 million, respectively, and was recorded as a component of price risk management assets and liabilities in the consolidated balance sheet. A hypothetical change of 1% on the underlying interest rate would have an effect of $2.1 million on the value of the swap as of May 31, 2007.

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In March 2007 the Partnership entered into interest rate swaps with an aggregate notional amount of $600.0 million with various financial institutions in anticipation of a debt offering in the fourth fiscal quarter of 2007. The fair value of these swaps at May 31, 2007 was $15.7 million and was recorded as component of price risk assets on the condensed consolidated balance sheet. The Partnership did not apply hedge accounting to these swaps and changes in fair value were recorded in other income. These swaps subsequently settled in June 2007 for a gain of $31.5 million.

ITEM 4. CONTROLS AND PROCEDURES

An evaluation was performed under the supervision and with the participation of our management, including the Co-Chief Executive Officers and Chief Financial Officer of our General Partner, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rule 13a 15(e) and 15d 15(e) of the Securities Exchange Act of 1934, as amended) as of May 31, 2007. Our management, including the Co-Chief Executive Officers and Chief Financial Officer does not expect that our disclosure controls and procedures or our internal controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. The inherent limitations in all control systems include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Based upon the evaluation, our management, including the Co-Chief Executive Officers and Chief Financial Officer of our General Partner, concluded that our disclosure controls and procedures are adequate and effective to ensure that information required to be disclosed by us in our periodic filings under the Securities and Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission s rules and forms.

Other than changes resulting from the Titan and Transwestern acquisitions, there have been no changes in our internal controls over financial reporting (as defined in Rule 13(a) 15 or Rule 15d 15(f) of the Exchange Act) during the three months ended May 31, 2007, that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

We continue to evaluate Titan s business and are making various changes to its operating and organizational structure based on our business plan. We are in the process of implementing our internal control structure over the operations of Titan. We expect that this effort will continue into future fiscal quarters of 2007 due to the magnitude of the business.

We closed the acquisition of Transwestern on December 1, 2006 and have begun the integration of the internal control structure of Transwestern into our processes and controls. We expect that integration effort to continue during the remainder of our fiscal year 2007 and into fiscal year 2008, which may result in changes to Transwestern s operating and organizational structure. As permitted by the SEC rules, we intend to exclude Transwestern from our evaluation of the effectiveness of internal control over financial reporting for the year ending August 31, 2007, due to its size and complexity.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended August 31, 2006 and Note 15 - Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Form 10-Q for the quarter ended May 31, 2007.

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ITEM 1A. RISK FACTORS

In addition to the risks described in our Annual Report on Form 10-K for the year ended August 31, 2006, we are subject to the following additional risks:

The pipeline businesses are subject to competition.

The interstate pipeline business of Transwestern competes with those of other interstate and intrastate pipeline companies in the transportation of natural gas. The principal elements of competition among pipelines are rates, terms of service and the flexibility and reliability of service. Natural gas competes with other forms of energy available to our customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas and other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the capability to convert to alternate fuels and other factors, including weather and natural gas storage levels, affect the demand for natural gas in the areas served by Transwestern.

The success of the pipelines depends on the continued development of additional natural gas reserves in the vicinity of our facilities and our ability to access additional reserves to offset the natural decline from existing wells connected to our systems.

The amount of revenue generated by Transwestern depends substantially upon the volume of natural gas transported. As the reserves available through the supply basins connected to Transwestern s systems naturally decline, a decrease in development or production activity could cause a decrease in the volume of natural gas available for transmission. Investments by third parties in the development of new natural gas reserves connected to Transwestern s facilities depend on many factors beyond Transwestern s control.

The inability to continue to access Tribal lands could adversely affect Transwestern s ability to operate its pipeline system and the inability to recover the cost of right-of-way grants on tribal lands could adversely affect its financial results.

Transwestern s ability to operate its pipeline system on certain Tribal lands (lands held in trust by the United States for the benefit of a Native American Tribe) will depend on its success in maintaining existing right-of-way and obtaining new right-of-way on those Tribal lands. Securing additional right-of-way is also critical to Transwestern s ability to pursue expansion projects including Transwestern s proposed expansion of its San Juan lateral in New Mexico. We cannot assure that Transwestern will be able to acquire new right-of-way on Tribal lands or maintain access to existing right-of-way upon the expiration of the current grants. Our financial position could be adversely affected if the costs of new or extended right-of-way grants cannot be recovered in rates.

Transwestern is subject to FERC rate-making policies that could have an adverse impact on our ability to establish rates that would allow us to recover the full cost of operating the pipeline.

In general, rate-making policies by FERC could affect Transwestern s ability to establish rates, or to charge rates that would cover future increases in its costs, or even to continue to collect rates that cover current costs. Natural gas companies may not charge rates that have been determined not to be just and reasonable by FERC. The rates, terms and conditions of service provided by natural gas companies are required to be on file with FERC in FERC-approved tariffs. Pursuant to FERC s jurisdiction over rates, tariff rates may be challenged by complaint and proposed rate increases may be challenged by protest. Further, other than for rates set under market-based rate authority, the FERC may order refunds of amounts collected under rates that were in excess of a just and reasonable level when taking into consideration our pipeline system s cost of service. In addition, shippers (other than shippers who have agreed not to challenge our tariff rates through 2010 pursuant to our recent settlement agreement with these shippers) may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint. Any successful complaint or protest against Transwestern s rates could reduce our revenues associated with providing transmission services. We cannot assure you that we will be able to recover all of Transwestern s costs through existing or future rates.

The ability of regulated pipelines held in pass-through entities, like us, to include an allowance for income taxes has been subject to extensive litigation before FERC and the courts, and the FERC s current policy is subject to future review by the FERC and the courts.

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The ability of regulated pipelines held in tax-pass-through entities, like us, to include an allowance for income taxes has been subject to extensive litigation before FERC and the courts for a number of years. In its *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In July 2004, the D.C. Circuit issued its opinion in *BP West Coast Products, LLC v. FERC*, which upheld, among other things, the FERC s determination that certain rates of an interstate petroleum products pipeline, SFPP, were grandfathered rates under the Energy Policy Act of 1992 but vacated the portion of the FERC s decision applying the *Lakehead* policy. In the *Lakehead* decision, the FERC allowed an oil pipeline publicly traded partnership to include in its cost-of-service an income tax allowance to the extent that its unitholders were corporations subject to income tax. In May and June 2005, the FERC issued a statement of general policy, as well as an order on remand of *BP West Coast*, respectively, in which the FERC stated it will permit pipelines to include in cost of service a tax allowance to reflect actual or potential tax liability on their public utility income attributable to all partnership or limited liability company interests, if the ultimate owner of the interest has an actual or potential income tax liability on such income. Whether a pipeline s owners have such actual or potential income tax liability will be reviewed by the FERC on a case-by-case basis. Although the new policy is generally favorable for pipelines that are organized as pass-through entities, it still entails rate risk due to the case-by-case review requirement. In December 2005, the FERC issued its first case-specific oil pipeline review of the income tax allowance issues in the SFPP proceeding, reaffirming its new income tax allowance policy and directing SFPP to provide certain evidence necessary for the pipeline to determine its income allowance. Further, in the December 2005 order, the FERC concluded that for tax allowance purposes, the FERC would apply a rebuttable presumption that corporate partners of pass-through entities pay the maximum marginal tax rate of 35% and that non-corporate partners of pass-through entities pay a marginal rate of 28%. The FERC indicated that it would address the income tax allowance issues further in the context of SFPP s compliance filing submitted in March 2006. In December 2006, the FERC ruled on some of the issues raised as to the March 2006 SFPP compliance filing, upholding most of its determinations in the December 2005 order. FERC did revise its rebuttable presumption as to corporate partners marginal tax rate from 35% to 34%. The FERC s *BP West Coast* remand decision and the new tax allowance policy were appealed to the D.C. Circuit. In May 2007, the D.C. Circuit affirmed FERC s favorable tax allowance policy. As a result, we remain eligible to include an allowance in the tariff rates we charge for natural gas transportation on our Transwestern interstate pipeline system, subject to our ability to demonstrate compliance with FERC s policy. The specific terms and application of that policy remain subject to future review by FERC and the courts.

Transwestern is subject to regulation by FERC in addition to FERC rules and regulations related to the rates it can charge for its services.

FERC s regulatory authority also extends to:

- operating terms and conditions of service;
- the types of services Transwestern may offer to its customers;
- construction of new facilities;
- acquisition, extension or abandonment of services or facilities;
- accounts and records; and
- relationships with affiliated companies involved in all aspects of the natural gas and energy businesses.

FERC action in any of these areas or modifications of its current regulations can impair Transwestern s ability to compete for business, the costs it incurs in its operations, the construction of new facilities or its ability to recover the full cost of operating its pipeline. For example, the development of uniform interstate gas quality standards by FERC could create two distinct markets for natural gas an interstate market subject to uniform minimum quality standards and an intrastate market with no uniform minimum quality standards. Such a bifurcation of markets could make it difficult for our pipelines to compete in both markets or to attract certain gas supplies away from the intrastate market. The time FERC takes to approve the construction of new facilities could raise the costs of our projects to the point where they are no longer economic.

FERC has authority to review pipeline contracts. If FERC determines that a term of any such contract deviates in a material manner from a pipeline s tariff, FERC typically will order the pipeline to remove the term from the contract and execute and refile a new contract with FERC or, alternatively, to amend its tariff to include the deviating term, thereby offering it to all shippers. If FERC audits a pipeline s contracts and finds deviations that appear to be unduly discriminatory, FERC could conduct a formal enforcement investigation, resulting in serious penalties and/or onerous ongoing compliance obligations.

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Should Transwestern fail to comply with all applicable FERC administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the recently enacted Energy Policy Act of 2005, FERC has civil penalty authority under the Natural Gas Act to impose penalties for current violations of up to $1.0 million per day for each violation.

Finally, we cannot give any assurance regarding the likely future regulations under which we will operate Transwestern or the effect such regulation could have on our business, financial condition, and results of operations.

We are under investigation by the FERC and CFTC relating to certain trading and transportation activities.

As described in Note 16, Regulatory Matters, Commitment, Contingencies, and Environmental Matters Litigation and Contingencies, we are under investigation by the FERC and CFTC with respect to whether ETP engaged in manipulation or improper trading activities in the Houston Ship Channel market around the times of the hurricanes in the fall of 2005 and other prior periods in order to benefit financially from our commodities derivative positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel market. The FERC is also investigating certain of our intrastate transportation activities. Management believes that these agencies will require a payment in order to conclude these investigations on a negotiated settlement basis. It is also possible that third parties will assert claims for damages related to these matters. Our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the outcome of these matters; however, it is possible that the amount we become obligated to pay as a result of the final resolution of these matters, whether on a negotiated settlement basis or otherwise, will exceed the amount of our existing accrual related to these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available for distributions either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

The risk of competition with affiliates of our General Partner has increased.

Except as provided in our Partnership Agreement, affiliates of our General Partner are not prohibited from engaging in other businesses or activities, including those that might be in direct competition with us. On May 7, 2007, Enterprise GP Holdings, L.P. acquired a 34.9% non-controlling equity interest in LE GP, L.L.C., ETE s General Partner. Enterprise GP Holdings, L.P. and its subsidiaries are a North American midstream energy business. As a result, there is greater risk that competition with affiliates of our General Partner could occur.

We treat each purchaser of Common Units as having the same tax benefits without regard to the actual Common Units purchased. The IRS may challenge this treatment, which could result in a Unitholder owing more tax and may adversely affect the value of the Common Units.

To maintain the uniformity of the economic and tax characteristics of our Common Units, we have adopted certain depreciation and amortization positions that are inconsistent with existing Treasury Regulations. These positions may result in an understatement of deductions and losses and an overstatement of income and gain to our Unitholders. For example, we do not amortize certain goodwill assets, the value of which has been attributed to certain of our outstanding units. A subsequent holder of those units is entitled to an amortization deduction attributable to that goodwill under Internal Revenue Code Section 743(b). But, because we cannot identify these units once they are traded by the initial holder, we do not give any subsequent holder of a unit any such amortization deduction. This approach understates deductions available to those Unitholders who own those units and may result in those Unitholders believing that they have a higher tax basis in their units than is actually the case. This, in turn, may result in those Unitholders reporting less gain or more loss on a sale of their units than is actually the case.

The IRS may challenge the manner in which we calculate our Unitholder s basis adjustment under Section 743(b). If so, because neither we nor a Unitholder can identify the units to which this issue relates once the initial holder has traded them, the IRS may assert adjustments to all Unitholders selling units within the period under audit as if all Unitholders owned such units.

Any position we take that is inconsistent with applicable Treasury Regulations may have to be disclosed on our federal income tax return. This disclosure increases the likelihood that the IRS will challenge our positions and propose adjustments to some or all of our Unitholders.

A successful IRS challenge to this position or other positions we may take could adversely affect the amount of taxable income or loss allocated to our Unitholders. It also could affect the gain from a Unitholder s sale of Common Units and could have a negative impact on the value of the Common Units or result in audit adjustments to our Unitholders tax returns without the benefit of additional deductions. Moreover, because one of our subsidiaries that is organized as a C corporation for federal income tax purposes owns units in us, a successful IRS challenge could result in this subsidiary having more tax liability than we anticipate and, therefore, reduce the cash available for distribution to our partnership and, in turn, to you.

We have adopted certain valuation methodologies that may result in a shift of income, gain, loss and deduction between us and our public Unitholders. The IRS may challenge this treatment, which could adversely affect the value of our Common Units.

When we issue additional units or engage in certain other transactions, we determine the fair market value of our assets and allocate any unrealized gain or loss attributable to such assets to the capital accounts of our Unitholders and our General Partner. Although we may from time to time consult with professional appraisers regarding valuation matters, including the valuation of our assets, we make many of the fair market value estimates of our assets ourselves using a methodology based on the market value of our Common Units as a means to measure the fair market value of our assets. Our methodology may be viewed as understating the value of our assets. In that case, there may be a shift of income, gain, loss and deduction between certain Unitholders and our General Partner, which may be unfavorable to such Unitholders. Moreover, under our current valuation methods, subsequent purchasers of our Common Units may have a greater portion of their Internal Revenue Code Section 743(b) adjustment allocated to ETP s intangible assets and a lesser portion allocated to our tangible assets. The IRS may challenge our valuation methods, or our allocation of Section 743(b) adjustment attributable to our tangible and intangible assets, and allocations of income, gain, loss and deduction between the General Partner and certain of our Unitholders.

A successful IRS challenge to these methods or allocations could adversely affect the amount of taxable income or loss being allocated to our Unitholders. It also could affect the amount of gain on the sale of Common Units by our Unitholders and could have a negative impact on the value of our Common Units or result in audit adjustments to the tax returns of our Unitholders without the benefit of additional deductions.

The sale or exchange of 50% or more of our capital and profit interests during any twelve-month period will result in the termination of our partnership for federal income tax purposes.

Our partnership will be considered to have terminated for federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in our capital and profits within a twelve-month period. In order to determine whether a sale or exchange of 50% or more of the total interests in our capital and profits has occurred, we review information available to us related to transactions involving transfers of all our partnership interests, including reported transfers of Common Units by our affiliates and sales of Common Units pursuant to trading activity in the public markets. Moreover, a technical termination of ETE would cause a deemed sale or exchange of all of our partnership interests held by ETE. Therefore, we also review such transactions related to common units in ETE. However, the information we are able to obtain does not provide all of the information necessary to make a definitive determination, on a current basis, of whether there have been sales and exchanges of 50% or more of our capital and profits interests within the prior twelve-month period, and we may not have all of the information necessary to make this determination until several months following the time of the transfers that would cause the 50% threshold to be exceeded. Based on the information currently available to us, we believe that transfers of our capital and profits interests is approaching the 50% threshold, and, if there are any significant additional sales of our Common Units or the common units in ETE in the near future, we expect that this 50% threshold will be exceeded. It is possible that the 50% threshold has already been exceeded, although we do not believe that to be the case based upon available information.

If a termination of our partnership for federal income tax purposes occurs, the termination will, among other things, result in the closing of our taxable year for all unitholders and could result in a significant deferral of the depreciation deductions allowable in computing our taxable income. If this occurs, you will be allocated an increased amount of taxable income as a percentage of the cash distributed to you. Although the amount of increase cannot be estimated because it depends upon numerous factors including the timing of the termination, the amount could be material. Our termination would not affect our classification as a partnership for federal income tax purposes, but instead, we would be treated as a new partnership for tax purposes. If treated as a new partnership, we must make new tax elections and could be subject to penalties if we are unable to determine that a termination occurred.

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

Not Applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

The Partnership held a special meeting of its Common Unitholders on May 1, 2007. The meeting was held to act on a proposal to approve a change in the terms of the Partnership s Class G Units to provide that each Class G Unit was converted into one of the Partnership s Common Units and the issuance of additional Common Units upon such conversion upon the request of the holder of the Class G Units. The following votes were cast with respect to the proposal:

FOR	***AGAINST***	***ABSTAIN***	***BROKER NON VOTES***
74,618,825	552,040	358,819	0

ITEM 5. OTHER INFORMATION

On May 24, 2007, Transwestern issued a total of $307,000,000 aggregate principal amount of Senior Unsecured Series Notes (Unsecured Series Notes) comprised of the following:

Principal	**Interest Rate**	**Maturity Date**
$ 82,000,000	5.64%	May 24, 2017
150,000,000	5.89%	May 24, 2022
75,000,000	6.16%	May 24, 2037

The Partnership used $295,000,000 of the proceeds received to repay borrowings and accrued interest outstanding under the ETP Revolving Credit Facility and $12,000,000 for general partnership purposes. Interest is payable semi-annually, and the Unsecured Series Notes rank pari passu with Transwestern s other unsecured debt. The Unsecured Series Notes are prepayable at any time in whole or pro rata in part, subject to a premium or upon a change of control event, as defined.

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**
(1)	3.1	Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)

(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(21)	3.1.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)

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	Exhibit Number	Description
(21)	3.1.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(34)	3.1.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(35)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(49)	3.1.9	Amendment No. 9 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(47)	3.1.10	Amendment No. 10 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(1)	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(21)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(21)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(*)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(*)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(17)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.
(21)	4.2	Unitholder Rights Agreement dated January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.
(27)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(28)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors names therein and Wachovia Bank, National Association, as trustee.
(37)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(29)	4.7	Registration Rights Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(39)	4.8	Joinder to Registration Rights Agreement, dated February 24, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(41)	4.9	Third Supplemental Indenture dated as of July 29, 2005 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(42)	4.10	Registration Rights Agreement, dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers thereto.
(43)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(43)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.

	Exhibit Number		Description
(53)		4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(46)		4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(47)		4.15	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(1)		10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)		10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
(3)		10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
(5)		10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.
(6)		10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(9)		10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)		10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(11)		10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(1)		10.3	Form of Contribution, Conveyance and Assumption Agreement among Heritage Holdings, Inc., Heritage Propane Partners, L.P. and Heritage Operating, L.P.
(15)	**	10.6.3	Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
(26)	**	10.6.5	Form of Grant Agreement.
*	**	10.6.6	Amended and Restated 2004 Unit Plan.
(4)		10.16	Note Purchase Agreement dated as of November 19, 1997.
(5)		10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.
(6)		10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(7)		10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(8)		10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(11)		10.16.5	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(22)		10.16.6	Sixth Amendment Agreement dated as of November 18, 2003 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(8)		10.17	Contribution Agreement dated June 15, 2000 among U.S. Propane, L.P., Heritage Operating, L.P. and Heritage Propane Partners, L.P.
(8)		10.17.1	Amendment dated August 10, 2000 to June 15, 2000 Contribution Agreement.

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	Exhibit Number	Description
(8)	10.18	Subscription Agreement dated June 15, 2000 between Heritage Propane Partners, L.P. and individual investors.
(8)	10.18.1	Amendment dated August 10, 2000 to June 15, 2000 Subscription Agreement.
(13)	10.18.2	Amendment Agreement dated January 3, 2001 to the June 15, 2000 Subscription Agreement.
(14)	10.18.3	Amendment Agreement dated October 5, 2001 to the June 15, 2000 Subscription Agreement.
(8)	10.19	Note Purchase Agreement dated as of August 10, 2000.
(11)	10.19.1	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)	10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.
(22)	10.19.3	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(15)	10.26	Assignment, Conveyance and Assumption Agreement between U.S. Propane, L.P. and Heritage Holdings, Inc., as the former General Partner of Heritage Propane Partners, L.P. dated as of February 4, 2002.
(15)	10.27	Assignment, Conveyance and Assumption Agreement between U.S. Propane, L.P. and Heritage Holdings, Inc., as the former General Partner of Heritage Operating, L.P., dated as of February 4, 2002.
(18)	10.28	Assignment for Contribution of Assets in Exchange for Partnership Interest dated December 9, 2002 amount V-1 Oil Co., the shareholders of V-1 Oil Co., Heritage Propane Partners, L.P. and Heritage Operating, L.P.
(19)	10.30	Acquisition Agreement dated November 6, 2003 among the owners of U.S. Propane, L.P. and U.S. Propane, L.L.C. and La Grange Energy, L.P.
(19)	10.31	Contribution Agreement dated November 6, 2003 among La Grange Energy, L.P. and Heritage Propane Partners, L.P. and U.S. Propane, L.P.
(20)	10.31.1	Amendment No. 1 dated December 7, 2003 to Contribution Agreement dated November 6, 2003 among La Grange Energy, L.P. and Heritage Propane Partners, L.P. and U.S. Propane, L.P.
(19)	10.32	Stock Purchase Agreement dated November 6, 2003 among the owners of Heritage Holdings, Inc. and Heritage Propane Partners, L.P.
(23)	10.35	Purchase and Sale Agreement between TXU Fuel Company and Energy Transfer Partners, L.P. dated April 25, 2004.
(23)	10.35.1	First Amendment to Purchase and Sale Agreement and Closing Agreement between TXU Fuel Company and Energy Transfer Partners, L.P. dated June 1, 2004.
(24)	10.36	Third Amended and Restated Credit Agreement among Heritage Operating L.P. and the Banks dated March 31, 2004.
(30)	10.40	Credit Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Fleet National Bank, as syndication agent, BNP Paribas and The Royal Bank of Scotland, PLC, as co-documentation agents, and other lenders party thereto.

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	Exhibit Number		Description
(40)		10.40.1	First Amendment, dated as of February 24, 2005, to Credit Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Fleet National Bank, as syndication agent, BNP Paribas and The Royal Bank of Scotland, PLC, as co-documentation agents, and other lenders party thereto.
(31)		10.41	Guaranty, dated January 18, 2005, by the Subsidiary Guarantors in favor of Wachovia Bank, National Association, as the administrative agent for the lenders.
(40)		10.41.1	Guaranty Supplement dated February 24, 2005.
(32)		10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(33)		10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(36)		10.44	Loan Agreement, dated as of January 26, 2005 between La Grange Acquisition, L.P., as Borrower, and La Grange Energy, L.P., as Lender.
(53)	**	10.45	Summary of Director Compensation.
(44)		10.46	Credit Agreement, effective as of December 13, 2005, among the Partnership, Wachovia Bank, National Association as administrative agent, LC issuer and swingline lender, Bank of America, N.A. and Citibank, N.A., as co-syndication agents. BNP Paribas and The Royal Bank of Scotland PLC New York Branch, as co-documentation agents, and the other lenders party thereto.
(45)		10.47	Guaranty, effective as of December 13, 2005, by the Subsidiary Guarantors in favor of Wachovia Bank, National Association, as administrative agent for the lenders.
(48)		10.48	Credit Agreement dated as of May 31, 2006, among Energy Transfer Partners, L.P., as the Borrower, Credit Suisse, Cayman Islands Branch as administrative agent, and the other lenders party hereto Credit Suisse Securities (USA) LLC and Banc of America Securities, LLC, as joint lead arrangers and co-documentation and syndication agents.
(48)		10.49	Amended and Restated Credit Agreement dated as of June 29, 2006, among Energy Transfer Partners, L.P., as the Borrower, Wachovia Bank, National Association as administrative agent, LC issuer and swingline lender, Bank of America, N.A. and Citibank, N.A. as co-syndication agents, BNP Paribas and The Royal Bank of Scotland, plc, as co-documentation agents, Deutsche Bank Securities, Inc., Credit Suisse, Cayman Islands Branch, UBS Securities, LLC, JPMorgan Chase Bank, N.A. and SunTrust Bank as senior managing agents and the other lenders party hereto Wachovia Capital Markets, LLC as sole lead arranger and sole book manager.
(54)		10.49.1	First Amendment to Amended and Restated Credit Agreement, dated as of February 21, 2007, among Energy Transfer Partners, L.P. and Wachovia Bank, National Association, as the Administrative Agent under the Amended and Restated Credit Agreement, dated as of June 29, 2006, among Energy Transfer Partners, L.P., as the Borrower, and the other parties thereto.
(48)		10.50	Guarantee for the Amended and Restated Credit Agreement dated as of June 29, 2006.
(50)		10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(51)		10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.

	Exhibit Number	Description
(52)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.
(53)	10.54	Fourth Amended and Restated Credit Agreement dated as of August 31, 2006 between and among Heritage Operating L.P., as the Borrower, and the Banks now or hereafter signatory parties hereto, as lenders Banks and Bank of Oklahoma, National Association as administrative agent and joint lead arranger for the Banks, JPMorgan Chase Bank, N.A., as syndication agent for the Banks, and J.P. Morgan Securities Inc., as joint lead arranger for the Banks.
(*)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(*)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(*)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(54)	21.1	List of Subsidiaries.
(*)	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.

* Filed herewith.
** Denotes a management contract or compensatory plan or arrangement.
(1) Incorporated by reference to the same numbered Exhibit to Registrant s Registration Statement of Form S-1, File No. 333-04018, filed with the Commission on June 21, 1996.
(2) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1996.
(3) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended February 28, 1997.
(4) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended May 31, 1998.
(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1998.
(6) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1999.
(7) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2000.
(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated August 23, 2000.
(9) File as Exhibit 10.16.3.
(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.

(11) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(13) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2001.
(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated February 4, 2002.
(18) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated January 6, 2003.
(19) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2003.
(20) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 2003.
(21) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(22) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(23) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed June 14, 2004.
(24) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2004.
(25) Incorporated by reference to Annex A of the Registrant s Schedule 14A Proxy Statement filed May 18, 2004.
(26) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed November 1, 2004.
(27) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed January 19, 2005.
(28) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed January 19, 2005.
(29) Incorporated by reference to Exhibit 4.3 to the Registrant s Form 8-K filed January 19, 2005.
(30) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed January 19, 2005.
(31) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed January 19, 2005.
(32) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed February 1, 2005.
(33) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed February 1, 2005.

(34) Incorporated by reference to Exhibit 3.1.7 to the Registrant s Form 8-K filed March 16, 2005.
(35) Incorporated by reference to Exhibit 3.1.8 to the Registrant s Form 8-K filed February 9, 2006.
(36) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed March 17, 2005.
(37) Incorporated by reference to Exhibit 10.45 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(39) Incorporated by reference to Exhibit 10.39.1 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(40) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(41) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed August 2, 2005.
(42) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed August 2, 2005.
(43) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K/A for the year ended August 31, 2005.
(44) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed December 16, 2005.
(45) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed December 16, 2005.
(46) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed October 25, 2006.
(47) Incorporated by reference to Exhibit 3.1.10 to the Registrant s Form 8-K filed November 3, 2006.
(48) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2006.
(49) Incorporated by reference to Exhibit 3.1.9 to the Registrant s Form 8-K filed May 3, 2006.
(50) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed September 18, 2006.
(51) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed September 18, 2006.
(52) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed September 18, 2006.
(53) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2006.
(54) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2007.

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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: July 10, 2007

By: /s/ Brian J. Jennings
Brian J. Jennings
(Chief Financial Officer duly authorized to sign on behalf of the registrant)