JAMBA, INC.
Form 10-Q
May 28, 2009
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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 April 21, 2009

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the transition period from __________ to __________

Jamba, Inc.

(Exact name of registrant as specified in its charter)

Delaware	001-32552	20-2122262
(State or other jurisdiction of incorporation)	(Commission File No.)	(I.R.S. Employer Identification No.)

6475 Christie Avenue, Suite 150, Emeryville, California 94608

(Address of principal executive offices)

Registrant s telephone number, including area code: (510) 596-0100

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 the filing requirements for the past 90 days. Yes x No ¨

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

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

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

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

The number of shares of common stock of Jamba, Inc. issued and outstanding as of May 22, 2009 was 54,690,728.

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JAMBA, INC.

QUARTERLY REPORT ON FORM 10-Q

QUARTERLY PERIOD ENDED APRIL 21, 2009

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PART I - FINANCIAL INFORMATION

ITEM 1. UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

JAMBA, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share and per share amounts)	April 21, 2009	December 30, 2008
ASSETS		
Current assets:		
Cash and cash equivalents	$ 18,437	$ 20,822
Restricted cash	5,804	5,059
Receivables, net of allowances of $302 and $416	2,724	4,594
Inventories	3,392	3,435
Prepaid and refundable income taxes	183	5,670
Prepaid rent	1,396	185
Prepaid expenses and other current assets	1,463	1,328
Total current assets	33,399	41,093
Property, fixtures and equipment, net	86,933	95,154
Trademarks and other intangible assets, net	2,595	2,998
Restricted cash	1,914	2,659
Deferred income taxes	354	354
Other long-term assets	4,784	3,462
Total assets	$ 129,979	$ 145,720
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities:		
Accounts payable	$ 8,167	$ 8,089
Accrued compensation and benefits	8,450	7,667
Workers compensation and health insurance reserves	2,113	1,922
Accrued jambacard liability	26,230	30,764
Current portion of capital lease obligations	231	246
Other accrued expenses	10,954	12,074
Derivative liabilities	1,933	2,098
Total current liabilities	58,078	62,860
Note payable	23,224	22,829
Long-term capital lease obligations	195	281
Long-term workers compensation and health insurance reserves	1,914	2,659
Deferred rent and other long-term liabilities	15,838	16,670
Total liabilities	99,249	105,299
Commitments and contingencies (Note 8)		
Stockholders equity:		
Common stock, $.001 par value, 150,000,000 shares authorized, 54,690,728 shares issued and outstanding	55	55

Additional paid-in capital	358,771	358,258
Accumulated deficit	(328,096)	(317,892)
Total stockholders equity	30,730	40,421
Total liabilities and stockholders equity	$ 129,979	$ 145,720

See accompanying notes to condensed consolidated financial statements.

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JAMBA, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except share and per share amounts)	16 Week Period Ended April 21, 2009	April 22, 2008
Revenue:		
Company stores	$ 87,019	$ 98,632
Franchise and other revenue	1,851	2,921
Total revenue	88,870	101,553
Costs and operating expenses:		
Cost of sales	21,207	26,379
Labor	31,918	37,998
Occupancy	13,748	13,379
Store operating	9,839	13,823
Depreciation and amortization	6,110	7,812
General and administrative	11,723	15,299
Impairment of long-lived assets	3,026	4,036
Other operating	236	2,382
Total costs and operating expenses	97,807	121,108
Loss from operations	(8,937)	(19,555)
Other income (expense):		
Gain from derivative liabilities	165	5,642
Interest income	334	186
Interest expense	(1,749)	(112)
Total other (expense) income	(1,250)	5,716
Loss before income taxes	(10,187)	(13,839)
Income tax (expense) benefit	(17)	7,408
Net loss	$ (10,204)	$ (6,431)
Weighted-average shares used in the computation of loss per share:		
Basic	54,690,728	52,637,131
Diluted	54,690,728	52,637,131
Loss per share:		
Basic	$ (0.19)	$ (0.12)
Diluted	$ (0.19)	$ (0.12)

See accompanying notes to condensed consolidated financial statements.

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JAMBA, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)	16 Week Period Ended April 21, 2009	16 Week Period Ended April 22, 2008
Cash (used in) provided by operating activities:		
Net loss	$ (10,204)	$ (6,431)
Adjustments to reconcile net loss to cash provided by (used in) operating activities:		
Depreciation and amortization	6,110	7,812
Impairment of long-lived assets	3,026	4,036
Store lease termination, closure costs and disposals	477	593
Share-based compensation	513	1,132
Jambacard breakage income and amortization, net	595	(324)
Bad debt and inventory reserves	(206)	48
Deferred rent	51	1,077
Deferred income taxes		(7,437)
Equity loss from joint ventures		107
Gain from derivative liabilities	(165)	(5,642)
Accretion of note payable	395	
Changes in operating assets and liabilities:		
Receivables	1,838	2,174
Inventories	219	(728)
Prepaid rent	(1,211)	2,324
Prepaid and refundable taxes	5,487	141
Prepaid expenses and other current assets	(135)	(1,261)
Other long-term assets	(222)	(11)
Accounts payable	(627)	3,367
Accrued compensation and benefits	783	4,201
Workers compensation and health insurance reserves	(554)	292
Accrued jambacard liability	(5,129)	(4,128)
Other accrued expenses	(1,120)	272
Other long-term liabilities	(708)	
Cash (used in) provided by operating activities	(787)	1,614
Cash used in investing activities:		
Capital expenditures	(1,797)	(13,982)
Proceeds from sale of stores	300	
Decrease in restricted cash		518
Cash used in investing activities	(1,497)	(13,464)
Cash used in financing activities:		
Borrowings on debt facility		398
Payment of debt issuance costs		(448)
Payment on capital leases	(101)	
Cash used in financing activities	(101)	(50)
Net decrease in cash and cash equivalents	(2,385)	(11,900)

Cash and cash equivalents at beginning of period	20,822	23,016
Cash and cash equivalents at end of period	$ 18,437	$ 11,116
Supplemental cash flow information:		
Cash paid for interest	$ 1,829	$ 97
Income taxes paid	5	47

See accompanying notes to condensed consolidated financial statements.

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JAMBA, INC.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

1. BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

Jamba, Inc., a Delaware corporation, and its wholly-owned subsidiary, Jamba Juice Company (the Company), is a retailer of premium quality blended-to-order fruit smoothies, squeezed-to-order juices, blended beverages and healthy snacks. As of April 21, 2009, there were 732 locations consisting of 499 company-owned and operated stores (Company Stores) and 233 franchise stores (Franchise Stores).

Unaudited Interim Financial Information The condensed consolidated balance sheet as of April 21, 2009 and the condensed consolidated statements of operations and cash flows for each of the 16 week periods ended April 21, 2009 and April 22, 2008 have been prepared by the Company, without audit, and have been prepared on the same basis as the Company s audited consolidated financial statements. In the opinion of management, such statements include all adjustments (which include only normal recurring adjustments except as discussed in Note 8) considered necessary to present fairly the financial position as of April 21, 2009 and the results of operations and cash flows for the 16 week periods ended April 21, 2009 and April 22, 2008. The condensed consolidated balance sheet as of December 30, 2008 has been derived from the Company s audited consolidated financial statements. Operating results for the 16 week period ended April 21, 2009 are not necessarily indicative of the results that may be expected for the year ending December 29, 2009. The Company reports its results of operations on a 52-week or 53-week fiscal year, which is comprised of thirteen 4-week periods or twelve 4-week periods and one 5-week period. The first fiscal quarter is sixteen weeks, the second and third fiscal quarters each are twelve weeks, and the fourth quarter is twelve or thirteen weeks.

Certain information and disclosures normally included in the notes to annual financial statements prepared in accordance with accounting principles generally accepted in the United States of America (GAAP) have been omitted from these interim financial statements pursuant to the rules and regulations of the Securities and Exchange Commission (the SEC). Accordingly, these interim financial statements should be read in conjunction with the Company s annual consolidated financial statements and notes thereto in the Company s Annual Report on Form 10-K for the year ended December 30, 2008.

Reclassifications Certain amounts have been reclassified on the condensed consolidated statement of operations to conform to the fiscal 2009 presentation.

Comprehensive Income Comprehensive income is defined as the change in equity during a period from transactions and other events, excluding changes resulting from investments from owners and distributions to owners. Comprehensive income (loss) equals net income (loss) for all periods presented.

Earnings (Loss) Per Share Loss per share is computed in accordance with SFAS No. 128, *Earnings per Share.* Basic earnings (loss) per share is computed based on the weighted-average of common shares outstanding during the period. Diluted earnings (loss) per share is computed based on the weighted-average number of common shares and potentially dilutive securities, which includes outstanding warrants and outstanding options and restricted stock awards granted under the Company s stock option plans. Anti-dilutive shares of 23.1 million and 21.8 million have been excluded from the calculation of diluted weighted-average shares outstanding in the 16 week periods ended April 21, 2009 and April 22, 2008, respectively.

The number of incremental shares from the assumed exercise of warrants and options was calculated by applying the treasury stock method. The following table summarizes the differences between the basic and diluted weighted-average shares outstanding used to compute diluted earnings (loss) per share:

	16 Week Period Ended				
	April 21, 2009	**April 22, 2008**			
Basic weighted-average shares outstanding	54,690,728	52,637,131			
Incremental shares from assumed exercise of warrants and options					
Balance, end of period	$ 15,466		$ 37,299	$ 15,466	$ 37,299

Components of Accumulated Other Comprehensive Income		
Commodity related derivative hedges	$ 15,460	$ 31,476
Interest rate derivative hedges	(1,497)	4,765
Available-for-sale securities	1,503	1,058
Balance, end of period	$ 15,466	$ 37,299

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 Six Months Ended February 28, 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	(97,759)	(168,413)	(20,054)
Issuance of Class G Units to Energy Transfer Equity, LP			1,200,000
General Partner capital contribution	24,489		
Unit-based compensation expense		6,071	
Net income	113,868	219,286	48,992
Balance, February 28, 2007	$ 123,048	$ 1,704,289	$ 1,228,938

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)

	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 617,895	$ 438,058
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(83,085)	(29,946)
Working capital settlement on prior year acquisitions		19,653
Capital expenditures	(542,930)	(255,101)
Advances to and investment in affiliates	(954,397)	
Proceeds from the sale of assets	19,200	3,875
Net cash used in investing activities	(1,561,212)	(261,519)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	2,493,030	1,013,188
Principal payments on debt	(2,428,492)	(1,168,322)
Net proceeds from issuance of limited partner units	1,200,000	132,387
Capital contribution from General Partner	24,489	2,702
Distributions to partners	(286,226)	(146,369)
Debt issuance costs	(9,451)	(1,196)
Net cash provided by (used in) financing activities	993,350	(167,610)
INCREASE IN CASH AND CASH EQUIVALENTS	50,033	8,929
CASH AND CASH EQUIVALENTS, beginning of period	26,041	24,914
CASH AND CASH EQUIVALENTS, end of period	$ 76,074	$ 33,843

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 February 28, 2007 and for the three-month and six-month periods ended February 28, 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 and subsidiaries as of February 28, 2007, and the Partnership s results of operations for the three-month and six-month periods ended February 28, 2007 and 2006, respectively, and cash flows for the six-month periods ended February 28, 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 have 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), a Delaware limited liability company 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 six months ended February 28, 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 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 February 28, 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 $722 for the three and six months ended February 28, 2007.

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 rates ranging from 1.2 percent to 2.86 percent per year. 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 February 28, 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 $830 within deferred assets and a corresponding regulatory liability of $830.

Transwestern accounts for its 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. 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. We plan to adopt this Staff Position beginning September 1, 2007.

SFAS No. 154, *Accounting Changes and Error Correction A Replacement of APB Opinion No. 20 and FASB Statement No. 3* (SFAS 154). In May 2005, the FASB issued SFAS 154 which requires that the direct effect of voluntary changes in accounting principle be applied retrospectively with all prior period financial statements presented on the new accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Indirect effects of a change should be recognized in the period of the change. SFAS 154 is effective for accounting changes and correction of errors made in fiscal years beginning after December 15, 2005. Management adopted the provisions of SFAS 154 September 1, 2006, as required. The impact of SFAS 154 will depend on the nature and extent of any voluntary accounting changes and correction of errors that occur in the future.

SFAS No. 155, *Accounting for Certain Hybrid Financial Instruments An Amendment of FASB Statements No. 133 and 140* (SFAS 155). SFAS 155 is effective for all financial instruments acquired, issued, or subject to a remeasurement (new basis) event occurring after the beginning of an entity s first fiscal year that begins after September 15, 2006. Early application is permitted only if: (a) it occurs at the beginning of an entity s fiscal year and (b) the entity has not yet issued any interim or annual financial statements for that fiscal year. We intend to adopt this statement when required at the start of fiscal year beginning September 1, 2007. The adoption of this statement is not expected to have a significant impact on us.

SFAS No. 157, *Fair Value Measurement*, (SFAS 157). This new standard provides guidance for using fair value to measure assets and liabilities. The FASB believes the standard also responds to investors requests for expanded information about the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect of fair value measurements on earnings. 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. 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, not just the company s mark-to-model value. SFAS 157 also requires expanded disclosure of the effect on earnings for items measured using unobservable data. Under SFAS 157, fair value refers to the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants in the market in which the reporting entity transacts. In this standard, the FASB clarifies the principle that fair value should be based on the assumptions market participants would use when pricing the asset or liability. In support of this principle, 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 Statement No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans An Amendment of SFAS Statements No. 87, 88, 106 and 132(R)*, (SFAS 158). Issued in September 2006, this statement requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multi-employer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income. SFAS 158 also requires an employer to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. We adopted the recognition and disclosure provisions of SFAS 158 on December 1, 2006 in connection with our acquisition of Transwestern, the effect of which was not material. The measurement provisions of the statement are effective for fiscal years ending after December 15, 2008. Management does not believe the adoption of the measurement provisions of this statement will have a material impact on our financial statements.

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. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings (or another performance indicator if the business entity does not report 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). This guidance is effective for interim and annual reporting periods beginning after December 15, 2006 with earlier application permitted. As a matter of policy, we report such taxes on a net basis. We will adopt this EITF during our 2007 fiscal quarter ending May 31, 2007.

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 are presently reviewing the impact of the adoption of SAB 108. However, we do not expect such adoption to have a material impact on our consolidated financial statements. We expect to adopt SAB 108 by August 31, 2007.

3. SIGNIFICANT ACQUISITIONS:

Fiscal year 2007 acquisitions

In September 2006 we acquired two small 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 acquisitions was financed primarily from advances under the ETP Revolving Credit Facility.

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 and long-term debt assumed	532,377
Other assumed long-term indebtedness	10,097
Current liabilities assumed	40,194
Cash acquired	(7,777)
Acquisition costs incurred	11,753
Total	$ 1,536,775

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During the six months ended February 28, 2007, HOLP and Titan collectively acquired substantially all of the assets of three propane businesses. The aggregate purchase price for these acquisitions totaled $10,608 which included $10,266 of cash paid, net of cash acquired, and liabilities assumed of $342. The cash paid for acquisitions was financed primarily with ETP s and HOLP s Senior Revolving Credit Facilities.

In December 2006 we purchased a 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 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.

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 February 28, 2007, net of cash acquired:

	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Accounts receivable	$	$ 20,101	$ 108
Inventory			43
Prepaid and other current assets		12,602	25
Property, plant, and equipment	47,656	1,254,968	9,222
Intangibles and other assets	23,015	133,880	475
Goodwill		115,224	735
Total assets acquired	70,671	1,536,775	10,608
Accounts payable		(7,432)	
Customer advances and deposits			(26)
Accrued and other current liabilities		(32,762)	
Short-term debt (paid in December 2006)		(13,000)	
Long-term debt		(519,377)	(316)
Other long-term obligations		(10,097)	
Total liabilities assumed		(582,668)	(342)
Net assets acquired	$ 70,671	$ 954,107	$ 10,266

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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 $442,967 at February 28, 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	$ 41,985
AFUDC gross-up	9,570
Environmental reserves	6,623
South Georgia deferred tax receivable	2,581
Other	891
Total Regulatory Assets acquired	$ 61,650

At February 28, 2007, all of Transwestern s regulatory assets are considered probable of recovery in rates.

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

	Midstream and Intrastate Transportation and Storage Acquisitions (Aggregated)	Transwestern Acquisition	Propane Acquisitions (Aggregated)
Contract rights (6 to 15 years)	$ 23,015	$ 47,582	$
Financing costs (7 to 9 years)		13,410	
Other			475
Total amortizable intangible assets	23,015	60,992	475
Goodwill		115,224	735
Total intangible assets and goodwill acquired	$ 23,015	$ 176,216	$ 1,210

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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 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 up to 500,000 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 previously announced 36-inch pipeline extending from the Barnett Shale and interconnecting with our Texoma pipeline near Paris, Texas. The MEP joint venture will be 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 has been 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. As of February 28, 2007, we are waiting on certain information required to reasonably estimate the fair value of one of the assets acquired in the Titan acquisition. We expect to complete the purchase allocation during our third quarter of fiscal year 2007. The Titan operations have been included since the date of acquisition, thus the condensed consolidated results of operations for the three and six months ended February 28, 2007 include the Titan results of operations for the entire period. However, the three and six months ended February 28, 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 six months ended February 28, 2007 and the three and six months ended February 28, 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 February 28, 2007 is not required.

	Six Months Ended February 28, 2007	Three Months Ended February 28, 2006	Six Months Ended February 28, 2006
Revenues	$ 3,509,817	$ 2,504,242	$ 4,981,784
Net income	$ 399,052	$ 260,835	$ 394,193
Limited Partners interest in net income	$ 284,846	$ 227,627	$ 335,857
Basic earnings per Limited Partner Unit	$ 1.85	$ 1.26	$ 2.01
Diluted earnings per Limited Partner Unit	$ 1.84	$ 1.26	$ 2.01

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:

	Six Months Ended February 28, 2007	2006
Net income	$ 382,146	$ 370,593
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	79,169	55,927
Amortization of finance costs charged to interest	2,156	1,369
Provision for loss on accounts receivable	851	473
Non-cash compensation on unit grants and other	6,071	5,827
Deferred income taxes	(2,417)	(861)
(Gain) loss on disposal of assets	1,285	(534)
Undistributed (earnings) losses of equity affiliates, net	(4,373)	168
Minority interests	1,110	2,104
Changes in operating assets and liabilities:		
Accounts receivable	(23,461)	23,170
Accounts receivable from related companies	(370)	3,811
Inventories	193,388	64,218
Deposits paid to vendors	54,837	4,250
Exchanges receivable	(8,700)	16,731
Prepaid expenses and other	16,412	(5,912)
Intangibles and other long-term assets	(951)	112
Regulatory assets	(5,055)	
Accounts payable	(45,624)	(144,105)
Accounts payable to related companies	1,497	(707)
Customer advances and deposits	(62,462)	(113,592)
Exchanges payable	7,274	(6,241)
Accrued and other current liabilities	(13,759)	8,563
Other long-term liabilities	8,393	(4,933)
Income taxes payable	(88)	21,527
Price risk management liabilities, net	30,566	136,100

Net cash provided by operating activities	$ 617,895	$ 438,058

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Supplemental cash flow information is as follows:

	Six Months Ended February 28, 2007	2006
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest, net of $10,543 and $ 2,321 capitalized for February 28, 2007 and 2006, respectively	$ 83,911	$ 10,654
Cash paid during the period for income taxes	$ 5,945	$ 3,007
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 six months ended February 28, 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 six months ended February 28, 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 February 28, 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 ended February 28, 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.

Accounts receivable consisted of the following:

	February 28, 2007	August 31, 2006
Accounts receivable midstream and transportation and storage	$ 532,059	$ 570,569

Accounts receivable propane	190,027	108,976
Less allowance for doubtful accounts	(4,129)	(4,000)
Total, net	$ 717,957	$ 675,545

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The activity in the allowance for doubtful accounts for the retail and wholesale propane segments consisted of the following for the six months ended February 28, 2007:

	February 28, 2007
Balance, beginning of period	$ 4,000
Provision for loss on accounts receivable	851
Accounts receivable written off, net of recoveries	(722)
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:

	February 28, 2007	August 31, 2006
Natural gas, propane and other NGLs	$ 178,024	$ 371,430
Appliances, parts and fittings and other	16,666	15,710
Total inventories	$ 194,690	$ 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.

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

	February 28, 2007	August 31, 2006
Land and improvements	$ 67,450	$ 63,220

Buildings and improvements (10 to 30 years)	104,927	66,739
Pipelines and equipment (10 to 65 years)	2,781,758	1,757,103
Natural gas storage (40 years)	91,282	91,177
Bulk storage, equipment and facilities (3 to 30 years)	455,272	108,834
Tanks and other equipment (5 to 30 years)	504,726	472,944
Vehicles (5 to 10 years)	136,991	120,710
Right-of-way (20 to 65 years)	180,471	104,650
Furniture and fixtures (3 to 10 years)	19,414	16,283
Linepack	38,994	24,821
Pad Gas	55,482	57,327
Other (5 to 10 years)	85,282	27,395
	4,522,049	2,911,203
Less Accumulated depreciation	(316,009)	(242,137)
	4,206,040	2,669,066
Plus Construction work-in-process	891,456	644,583
Property, plant and equipment, net	$ 5,097,496	$ 3,313,649

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Capitalized interest is included for pipeline construction projects. Interest is capitalized based on the current borrowing rate of our revolving credit facility. A total of $10,543 of interest was capitalized for pipeline construction projects during the six months ended February 28, 2007 (excluding AFUDC, see Note 2).

Depreciation expense for the periods is as follows:

Three Months Ended		Six Months Ended	
February 28,		February 28,	
2007	2006	2007	2006
$ 41,278	$ 26,641	$ 72,144	$ 51,205

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 six month period ended February 28, 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				3,777	3,777
Goodwill acquired			115,224	735	115,959
Sale of operations				(1,742)	(1,742)
Balance, end of period	$ 13,409	$ 10,327	$ 115,224	$ 583,443	$ 722,403

The purchase price allocations for the Transwestern and other fiscal 2007 acquisitions (see Note 3) and our Titan acquisition in fiscal 2006 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. We expect to complete the Titan purchase price allocation in our third quarter of fiscal 2007. There is no guarantee that the amounts allocated to goodwill will not change.

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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:

	February 28, 2007		August 31, 2006	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 31,609	$ (15,255)	$ 31,593	$ (13,012)
Customer lists (3 to 15 years)	129,161	(16,206)	87,480	(11,640)
Contract rights (6 to 15 years)	23,015	(226)		
Financing costs (3 to 15 years)	40,302	(6,372)	20,128	(4,441)
Consulting agreements (2 to 7 years)			132	(122)
Other (10 years)	2,677	(745)	2,677	(422)
Total amortizable intangible assets	226,764	(38,804)	142,010	(29,637)
Non-amortizable Trademarks	64,642		64,842	
Total intangible assets	291,406	(38,804)	206,852	(29,637)
Other long-term assets:				
Regulatory assets	61,650			
Investment in affiliates	12,651		41,344	
Long-term price risk management assets	1,726		2,192	
Other	30,831		14,400	
Total intangibles and other assets	$ 398,264	$ (38,804)	$ 264,788	$ (29,637)

Prior to February 28, 2007, the Partnership owned a 50% ownership interest in Mid-Texas Pipeline Company (Mid-Texas), 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 Mid-Texas was dissolved and each partner was assigned its 50% undivided interest in the pipeline. 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 will apply proportionate consolidation prospectively for our interest in the Mid-Texas pipeline. This represents a non-cash transaction.

Aggregate amortization expense of intangible assets is as follows:

	Three Months Ended		Six Months Ended	
	February 28,		February 28,	
	2007	2006	2007	2006
Reported in depreciation and amortization	$ 4,082	$ 2,373	$ 7,025	$ 4,722
Reported in interest expense	$ 1,317	$ 692	$ 2,156	$ 1,369

The estimated aggregate amortization expense for the next five fiscal years is $16,011 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 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 six month periods ended February 28, 2007 and 2006.

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10. ACCRUED AND OTHER CURRENT LIABILITIES:

Accrued and other current liabilities consist of the following:

	February 28, 2007	August 31, 2006
Capital expenditures	$ 53,068	$ 38,002
Employee wages and benefits	43,549	40,236
Operating expenses	12,013	16,839
Interest payable	23,229	13,956
Other accrued expenses	97,914	93,263
Total accrued and other current liabilities	$ 229,773	$ 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 six month periods ended February 28, 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.

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 six months ended February 28, 2007, we recognized current state income tax expense related to the Texas margin tax of $1,854. There was no comparable state tax expense for the periods ended February 28, 2006.

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

	Three Months Ended February 28,		Six Months Ended February 28,	
	2007	2006	2007	2006
Current provision:				
Federal	$ 3,336	$ 12,853	$ 6,487	$ 28,117
State	2,487	950	2,826	1,288
	5,823	13,803	9,313	29,405
Deferred benefit:				
Federal	(2,247)	(9,288)	(2,178)	(2,625)

State	(276)	(501)	(239)	(355)
	(2,523)	(9,789)	(2,417)	(2,980)
Total	$ 3,300	$ 4,014	$ 6,896	$ 26,425

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

	Three Months Ended February 28, 2007	Three Months Ended February 28, 2006	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006
Federal statutory tax rate	35.0%	35.0%	35.0%	35.0%
State income tax rate net of federal benefit	0.7%	3.4%	0.7%	3.4%
Earnings not subject to tax at the Partnership level	(34.7)%	(36.8)%	(33.9)%	(31.8)%
Effective tax rate	1.0%	1.6%	1.8%	6.6%

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 Common and Class G Units outstanding. 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 Common and Class G Units outstanding and of the effect of non-vested restricted units (Unit Grants) granted under the 2004 Unit Plan and predecessor plan computed using the treasury stock method.

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

	Three Months Ended February 28, 2007	Three Months Ended February 28, 2006	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006
Net income	$ 311,114	$ 250,785	$ 382,146	$ 370,593
Adjustments:				
General Partner s equity ownership	(6,222)	(5,016)	(7,643)	(7,412)
General Partner s incentive distributions	(54,345)	(22,679)	(106,225)	(40,767)
Limited Partner s interest in net income for statement of operations reporting	250,547	223,090	268,278	322,414
Additional earnings allocation to General Partner	(68,354)	(75,907)	(23,934)	(94,206)
Net income available to limited partners for income per unit computations	$ 182,193	$ 147,183	$ 244,344	$ 228,208
Weighted average limited partner units basic	136,977,139	107,815,792	128,184,154	107,352,608
Basic net income per limited partner unit	$ 1.33	$ 1.37	$ 1.91	$ 2.13

Weighted average limited partner units	136,977,139	107,815,792	128,184,154	107,352,608
Dilutive effect of Unit Grants	320,567	201,268	308,766	199,104
Weighted average limited partner units, assuming dilutive effect of Unit Grants	137,297,706	108,017,060	128,492,920	107,551,712
Diluted net income per limited partner unit	$ 1.33	$ 1.36	$ 1.90	$ 2.12

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13. DEBT OBLIGATIONS:

Long-term debt 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	(628)
Total long-term debt assumed	$ 519,372

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.

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.

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 February 28, 2007, there was a balance of $783,755 in revolving credit loans (including $63,455 in Swingline loans) and $57,306 in letters of credit. The weighted average interest rate on the total amount outstanding at February 28, 2007, was 5.979%. The total amount available under the ETP Revolving Credit Facility as of February 28, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $658,939. 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.

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 February 28, 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 February 28, 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 February 28, 2007 was $73,998.

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We were in compliance with all of the covenants of our consolidated debt agreements at February 28, 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 Class G Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of February 28, 2007, we had limited partner interests represented by 110,890,596 Common Units and 26,086,957 Class G 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.

Common Units

The change in Common Units during the six month period ended February 28, 2007 is as follows:

Balance, beginning of period	110,726,999
Issuance of restricted Common Units under our unit-based compensation plans	163,597
Balance, end of period	110,890,596

Of the total restricted Common Units issued during the period, 154,239 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 February 28, 2007, there are 1,333 unvested awards remaining under the Restricted Unit Plan (which 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 six month period ended February 28, 2007 is as follows:

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

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 provide that they may be converted to Common Units 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. Prior to conversion of the Class G Units, the Class G Units will share in Partnership distributions and are entitled to all items of Partnership income, gain, loss, deduction and credit as if the Class G Units were Subordinated Units. Upon receiving the requisite approval by our Common Unitholders under a proposal to convert the Class G Units to Common Units, all Class G Units will convert to Common Units on a one-for-one basis. The Class G Units were issued to ETE pursuant to a customary agreement, and registration rights have been granted to ETE.

The Partnership will hold a meeting of its unitholders on May 1, 2007 to seek unitholder approval of the conversion of Class G Units to Common Units (see Note 20).

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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 March 26, 2007, we declared a per unit cash distribution of $0.7875, or $3.15 per Limited Partner Unit annually (a $0.0188 increase per Limited Partner Unit) for the quarter ended February 28, 2007, which will be paid on April 13, 2007 to Unitholders of record at the close of business on April 6, 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 quarterly distribution of $55,151 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 six months ended February 28, 2007 was as follows:

Limited Partners -	
Common Units	$ 172,573
Class E Units	6,242
Class G Units	40,598
General Partners -	
2% Ownership	6,646
Incentive Distribution Rights	106,225
	$ 332,284

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 $2,908 and $5,380 for the three months ended February 28, 2007 and 2006, respectively, and $6,071 and $5,827 for the six months ended February 28, 2007 and 2006, respectively, related to unit-based compensation plans, as discussed below.

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 specific general guidelines as defined by the Plan. All outstanding awards shall fully vest into units upon any Change in Control as defined by the Plan, or upon such terms as the Compensation Committee may require at the time the award is granted.

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Employee grants awarded under the 2004 Unit Plan will vest over a three-year period based upon the achievement of certain performance criteria. The expected life of each grant is assumed to be the minimum vesting period under certain performance criteria of each grant. Vesting occurs based upon the total return to our Unitholders as compared to a group of publicly traded partnership peer companies. One third of the awards will vest and convert to Common Units annually based on achievement of the performance criteria. 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 six months ended February 28, 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 February 28, 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 six months ended February 28, 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	(154,239)	23.78
Awards forfeited	(61,472)	33.38
Unvested awards as of February 28, 2007	541,539	$ 38.02

The total expected compensation expense to be recognized related to the unvested employee awards as of February 28, 2007 is $5,960 for the remainder of fiscal year 2007, $4,885 for fiscal year 2008, and $1,671 for fiscal year 2009.

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 (as of October 2006, see below) divided by the fair market value of a Common Unit on such date (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 six months ended February 28, 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 six months ended February 28, 2007, the grant-date average per unit cash distributions were estimated to be $4.95.

The following table shows the activity of the Director Grants during the six months ended February 28, 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 February 28, 2007	12,166	$ 27.63

The total expected compensation expense to be recognized related to the unvested Director Awards as of February 28, 2007 is expected to be $89 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 February 28, 2007, there have been no Long-Term Incentive Grants made under the Plan.

Related Party Awards

Through February 28, 2007, a partnership controlled by a Director of our General Partner awarded to a new officer of ETP certain rights related to units of ETE previously issued by ETE to such Director. 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 employees assuming no forfeitures. Awards granted for the six months ended February 28, 2007 result in a total non-cash compensation expense of approximately $8,800 to be recognized over the related vesting period. For the three and six month periods ended February 28, 2007, we recognized non-cash compensation expense of $354 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	$ 2,124
Fiscal 2008	2,969
Fiscal 2009	1,717
Fiscal 2010	1,009
Fiscal 2011	508
Fiscal 2012	119

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 October 31, 2006, in

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Docket No. RP06-614 the FERC issued its Order Accepting and Suspending Tariff Sheets Subject to Refund and Establishing a Hearing and Technical Conference (Commission s October 31, 2006 Order). In this Order the Commission accepted and suspended the revised tariff sheets for the maximum five-month statutory period to be effective April 1, 2007, subject to refund, and subject to the outcome of a hearing established by this order. Transwestern and the active parties in this proceeding engaged in settlement negotiations to resolve all issues set for hearing by the Commission s October 31, 2006 Order. On March 9, 2007, Transwestern filed with the FERC its Stipulation and Agreement of Settlement (Stipulation and Agreement) which, if approved by the commission, will settle these matters. The Stipulation 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 August 1, 2002, the FERC issued an Order to Respond (August 1 Order) to Transwestern. The order required Transwestern, within 30 days of the date of the order, to provide written responses stating why the FERC should not find that: (i) Transwestern violated FERC s accounting regulations by failing to maintain written cash management agreements with Enron; and (ii) the secured loan transactions entered into by Transwestern in November 2001 were imprudently incurred and why the costs arising from such transactions should be passed on to ratepayers. On September 2, 2002, Transwestern filed a response to the August 1 Order and subsequently entered into a procedural settlement with the FERC staff that resolved, as to Transwestern, the issues raised by the August 1 Order. The FERC approved this settlement on October 31, 2002; however, a group of Transwestern s customers filed a request for clarification and/or rehearing of the FERC order approving the settlement. This customer group claimed that there is an inconsistency between the language of the settlement agreement and the language of the FERC order approving the settlement. This alleged inconsistency relates to Transwestern s ability to pass through to its ratepayers the costs of any replacement or refinancing of the secured loan transactions entered into by Transwestern in November 2001. Transwestern filed a response to the customer group s request for rehearing and/or clarification and this matter is currently awaiting FERC action. If approved, the March 9, 2007 Stipulation in Docket No. RP06-614 (discussed above) would provide for the termination of this proceeding.

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. Transwestern has incurred expenditures of $31,487 through February 28, 2007 for the Phoenix Expansion project.

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 $5,838 and $12,189 for the three and six months ended February 28, 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.

On October 3, 2006, we entered into a long-term agreement with CenterPoint Energy Resources Corp (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of this agreement, 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 agreement 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. This agreement went into effect on April 1, 2007.

We assumed in our HPL acquisition 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

The Operating Partnerships may, from time to time, be involved in litigation and claims arising out of their respective 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 and our Operating Partnerships 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 Commission. 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 is scheduled for April 24, 2007 regarding Transwestern s Supplemental Brief for Attorneys fees which was filed on January 8, 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 has been acquired. Transwestern resolved this matter by filing a renewal application with the BIA during October 2002. However, discussions are ongoing with the BIA to approve the renewal application.

Effective December 16, 2004, Citicorp North America, Inc. (Citicorp) claimed, in its capacity as the Paying Agent and Co-Administrative Agent, that any recovery in the litigation captioned Enron Corp. et al. v. Citigroup, Inc. et al. (the Litigation), together with legal fees and expenses incurred by Citicorp in defending the Litigation, would be indemnity obligations (the Obligations) of Transwestern under its Credit Agreement dated November 13, 2001. Under the terms of the Purchase Agreement, CCE Holdings, LLC and certain of its subsidiaries are indemnified against the Obligations by Enron and certain of its subsidiaries. In January of 2005, Enron gave notice that it would assume the defense of and indemnify CCE Holdings, LLC, against any action by Citigroup to collect from Transwestern. Discovery is ongoing in the adversary proceeding and Transwestern has not been joined in the litigation. Accordingly, Transwestern does not believe that it has any material liability from Citicorp s claims.

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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 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 into certain of ETP s transportation activities. In connection with these investigations, we have responded to discovery subpoenas, 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 fall of 2005 and other periods. It is our position that our trading and transportation activities during these periods complied in all material respects with applicable rules and regulations. We anticipate that we will engage in discussions with these agencies related to their views of possible violations of applicable laws and regulations, and potential penalties related thereto, and that these discussions will involve settlement negotiations to resolve these matters. Management believes that these agencies will require a payment in order to conclude these investigations in 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.

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.

As of February 28, 2007 and August 31, 2006, an accrual of $30,275 and $32,148, respectively, was recorded as accrued and other 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.

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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 $13,100. Transwestern has requested recovery of the portion of soil and groundwater remediation not related to PCBs in the current rate case anticipated to become effective April 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 $200 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 February 28, 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 HOLP, it is believed that HOLP s liability if such action were to be taken by the EPA would not have a material adverse effect on our financial condition or results of operations.

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. agreed to indemnify ETC OLP 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 ETC OLP 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 February 28, 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

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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 February 28, 2007 and August 31, 2006, an accrual on an undiscounted basis of $17,552 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 February 28, 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.

In December 2003, the U.S. Department of Transportation issued a final 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. The final rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002. The final rule was effective as of January 14, 2004. Based on the results of our current pipeline integrity testing programs, we estimate that compliance with this final rule for our existing transportation assets will result in capital costs of $7,006 during the period between the remainder of calendar year 2007 to 2008, as well as operating and maintenance costs of $8,574 during that period. 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 our 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 flow 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 $32,970 and $87,806 as of February 28, 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 $119,548 and $122,716 for the three and six months ended February 28, 2007, respectively, and gains of $142,989 and $41,675 for the three and six months ended February 28, 2006, respectively, related to commodity financial instruments that were previously reported in OCI.

We expect gains of $18,038 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. 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

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consolidated statements of operations on a net basis. Net losses associated with trading activities for the three months ended February 28, 2007 were $1,719 and net gains for the six months ended February 28, 2007 were $1,244. Included in the trading revenue was unrealized losses of $6,329 and $17,529 for the three and six months ended February 28, 2007, respectively. For the three and six months ended February 28, 2006, trading activities consisted of losses of $2,743 and gains of $49,837, respectively, including unrealized losses of $25,530 and $19,117, respectively.

The following table details the outstanding commodity-related derivatives as of February 28, 2007 and August 31, 2006, respectively:

February 28, 2007	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	23,023,316	2007-2009	$ 3,347
Swing Swaps IFERC	Gas	17,592,500	2007-2008	1,275
Fixed Swaps/Futures	Gas	(23,765,000)	2007	25,294
Forward Physical Contracts	Gas	(4,043,550)	2007-2008	(320)
Options	Gas	(602,000)	2007-2008	742
Forward/Swaps in Gallons	Propane	4,452,000	2007	(524)
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(3,880,000)	2007-2008	$ 5,514
Swing Swaps IFERC	Gas	68,200	2007	(6)
Forward Physical Contracts	Gas		2007	(1,141)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,282,500	2007	$ (174)
Fixed Swaps/Futures	Gas	2,330,000	2007	189
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.

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During the three months ended February 28, 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 through March. 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 February 28, 2007 and 2006, the Partnership recognized previously deferred unrealized gains of $17,848 and $84,680 from the discontinued application of hedge accounting, which is included in the reclassification into earnings from OCI during the three and six months ended February 28, 2007 and 2006, respectively. The Partnership classified the $17,848 and $84,680 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.

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. Accordingly, changes in the fair value of these instruments are recorded as interest expense on the consolidated statements of operations. These instruments settled during the six months ended February 28, 2007 for a gain of $567.

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 $14,955 and $8,699 on the consolidated balance sheets as of February 28, 2007 and August 31, 2006, respectively. 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 subsequent to February 28, 2007 at a cost of approximately $13,400.

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 February 28, 2007, and August 31, 2006 was a net liability and asset of $425 and $519, respectively, and was recorded as a component of price risk management assets and liabilities in the consolidated balance sheet. We elected to not apply hedge accounting to these financial instruments. Accordingly, changes in the fair value of these instruments are recorded as interest expense on the condensed consolidated statements of operations.

We reclassified into earnings gains of $2,662 and losses of $51 for the three and six months ended February 28, 2007, respectively, related to interest rate swaps that were previously reported in OCI. Losses of $8 and gains of $756 were reclassified into earnings for the three and six months ended February 28, 2006 related to interest rate swaps previously reported in OCI. We expect gains of $197 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.

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

	Three Months Ended February 28,		Six Months Ended February 28,	
	2007	2006	2007	2006
Commodity-related				
Unrealized gains (losses) recognized in revenues and cost of products sold related to commodity-related derivative activity, excluding ineffectiveness	$ 23,817	$ (35,744)	$ 15,885	$ 37,809
Ineffective portion of derivatives qualifying for hedge accounting	(1,103)	35,645	1,482	17,323
Realized gains included in revenues and cost of products sold	102,889	109,748	113,866	100,455
Interest rate swaps				
Unrealized gains (losses) on interest rate swap included in interest expense, excluding ineffectiveness	$ 339	$	$ (1,573)	$ (151)

Ineffective portion of derivatives qualifying for hedge accounting	2,390		(436)	771
Realized gains (losses) on interest rate swap included in interest expense	345	(8)	1,137	135

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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 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:

As of February 28, 2007 and August 31, 2006, we had advances due from a propane joint venture of $7,804 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 six months ended February 28, 2007 and 2006, we made payments totaling $848 and $1,813, 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 February 28, 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 other than Transwestern (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

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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 February 28, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
ASSETS						
CURRENT ASSETS:						
Cash and cash equivalents	$ 1,710	$	$ 20,666	$ 53,698	$	$ 76,074
Marketable securities				4,026		4,026
Accounts receivable, net		513,597	39,731	164,965	(336)	717,957
Inventories		105,530	14,249	74,911		194,690
Deposits paid to vendors		32,970				32,970
Exchanges receivable		29,838		8,347		38,185
Price risk management assets		14,706	104			14,810
Prepaid expenses and other	675,847	38,645	29,017	19,791	(725,056)	38,244
Total current assets	677,557	735,286	103,767	325,738	(725,392)	1,116,956
PROPERTY, PLANT AND EQUIPMENT, net		3,108,399	182,973	1,806,124		5,097,496
GOODWILL		23,736	257,987	440,680		722,403
LONG-TERM NOTES RECEIVABLE FROM RELATED PARTY	283,815				(283,815)	
DEFERRED TAX ASSET			1,353		(1,353)	
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	5,027,735	29,376	67,152	365,235	(5,130,038)	359,460
Total assets	$ 5,989,107	$ 3,896,797	$ 613,232	$ 2,937,777	$ (6,140,598)	$ 7,296,315
LIABILITIES AND PARTNERS CAPITAL						
CURRENT LIABILITIES:						
Accounts payable	$ 300	$ 407,058	$ 23,164	$ 103,307	$ (336)	$ 533,493
Exchanges payable		31,653		6,873		38,526
Customer advances and deposits		5,366	11,805	29,930		47,101
Accrued and other current liabilities	52,373	803,408	24,888	74,160	(725,056)	229,773
Price risk management liabilities	14,955	4,026	524			19,505
Current maturities of long-term debt			700	39,858		40,558
Total current liabilities	67,628	1,251,511	61,081	254,128	(725,392)	908,956
LONG-TERM DEBT, net of discount, less current maturities	2,728,934		456	458,504		3,187,894
LONG-TERM NOTES PAYABLE FROM RELATED PARTY				283,815	(283,815)	
DEFERRED INCOME TAXES		50,784		55,058	(1,353)	104,489
OTHER NONCURRENT LIABILITIES		2,030	3,478	17,727		23,235
COMMITMENTS AND CONTINGENCIES						

	2,796,562	1,304,325	65,015	1,069,232	(1,010,560)	4,224,574
PARTNERS CAPITAL	3,192,545	2,592,472	548,217	1,868,545	(5,130,038)	3,071,741
Total liabilities and partners capital	$ 5,989,107	$ 3,896,797	$ 613,232	$ 2,937,777	$ (6,140,598)	$ 7,296,315

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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

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the three months ended February 28, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 1,434,680	$	$ 58,158	$	$ 1,492,838
Propane and other			150,422	419,220		569,642
Total revenue		1,434,680	150,422	477,378		2,062,480
COSTS AND EXPENSES:						
Cost of products sold midstream and transportation and storage		1,138,709				1,138,709
Cost of products sold propane and other			87,410	259,697		347,107
Operating expenses		46,247	23,697	63,865		133,809
Depreciation and amortization		17,578	3,093	24,689		45,360
Selling, general and administrative	(407)	24,282	1,210	14,048		39,133
Total costs and expenses	(407)	1,226,816	115,410	362,299		1,704,118
OPERATING INCOME	407	207,864	35,012	115,079		358,362
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(35,522)	(3,331)	95	(14,079)	12,065	(40,772)
Equity in earnings (losses) of affiliates	335,580	(539)		25	(335,580)	(514)
Loss on disposal of assets		(2,422)	(374)	(433)		(3,229)
Interest and other income, net	10,649	1,484	1,165	190	(12,065)	1,423
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	311,114	203,056	35,898	100,782	(335,580)	315,270
Income tax expense (benefit)		1,418	(1,353)	3,235		3,300
INCOME BEFORE MINORITY INTERESTS	311,114	201,638	37,251	97,547	(335,580)	311,970
Minority interests				(856)		(856)
NET INCOME	$ 311,114	$ 201,638	$ 37,251	$ 96,691	$ (335,580)	$ 311,114

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the three months ended February 28, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES:					
Midstream and transportation and storage	$	$ 2,083,303	$	$	$ 2,083,303
Propane and other			366,513		366,513
Total revenues		2,083,303	366,513		2,449,816
COSTS AND EXPENSES:					
Cost of products sold midstream and transportation and storage		1,785,053			1,785,053
Cost of products sold propane and other			223,778		223,778
Operating expenses		48,913	50,783		99,696
Depreciation and amortization		14,942	14,072		29,014
Selling, general and administrative	6,200	19,382	5,873		31,455
Total costs and expenses	6,200	1,868,290	294,506		2,168,996
OPERATING INCOME (LOSS)	(6,200)	215,013	72,007		280,820
OTHER INCOME (EXPENSE):					
Interest expense, net of interest capitalized	(22,464)	(1,872)	(8,052)	3,846	(28,542)
Equity in earnings (losses) of affiliates	275,770	234	(128)	(275,770)	106
Gain on disposal of assets		584	78		662
Interest and other income (expense), net	3,679	2,536	(67)	(3,846)	2,302
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	250,785	216,495	63,838	(275,770)	255,348
Income tax expense		1,101	2,913		4,014
INCOME BEFORE MINORITY INTERESTS	250,785	215,394	60,925	(275,770)	251,334
Minority interests			(549)		(549)
NET INCOME	$ 250,785	$ 215,394	$ 60,376	$ (275,770)	$ 250,785

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the six months ended February 28, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidation Adjustments	Consolidated
REVENUES:						
Midstream and transportation and storage	$	$ 2,497,124	$	$ 58,158	$	$ 2,555,282
Propane and other			235,107	660,536		895,643
Total revenue		2,497,124	235,107	718,694		3,450,925
COSTS AND EXPENSES:						
Cost of products sold midstream and transportation and storage		2,022,692				2,022,692
Cost of products sold propane and other			140,134	410,333		550,467
Operating expenses		97,932	45,832	122,426		266,190
Depreciation and amortization		34,494	5,957	38,718		79,169
Selling, general and administrative	3,229	40,774	2,402	19,798		66,203
Total costs and expenses	3,229	2,195,892	194,325	591,275		2,984,721
OPERATING INCOME (LOSS)	(3,229)	301,232	40,782	127,419		466,204
OTHER INCOME (EXPENSE):						
Interest expense, net of interest capitalized	(73,975)	(3,098)	(1,208)	(20,503)	16,550	(82,234)
Equity in earnings (losses) of affiliates	444,262	(763)		24	(439,150)	4,373
Gain (loss) on disposal of assets		(2,386)	(374)	1,475		(1,285)
Interest and other income, net	15,088	3,244	1,156	156	(16,550)	3,094
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	382,146	298,229	40,356	108,571	(439,150)	390,152
Income tax expense (benefit)		3,412	(1,354)	4,838		6,896
INCOME BEFORE MINORITY INTERESTS	382,146	294,817	41,710	103,733	(439,150)	383,256
Minority interests				(1,110)		(1,110)
NET INCOME	$ 382,146	$ 294,817	$ 41,710	$ 102,623	$ (439,150)	$ 382,146

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the six months ended February 28, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
REVENUES:					
Midstream and transportation and storage	$	$ 4,291,837	$	$	$ 4,291,837
Propane and other			574,599		574,599
Total revenues		4,291,837	574,599		4,866,436
COSTS AND EXPENSES:					
Cost of products sold midstream and transportation and storage		3,744,422			3,744,422
Cost of products sold propane and other			355,036		355,036
Operating expenses		102,590	99,777		202,367
Depreciation and amortization		28,361	27,566		55,927
Selling, general and administrative	9,020	38,169	9,065		56,254
Total costs and expenses	9,020	3,913,542	491,444		4,414,006
OPERATING INCOME (LOSS)	(9,020)	378,295	83,155		452,430
OTHER INCOME (EXPENSE):					
Interest expense, net of interest capitalized	(43,068)	(4,192)	(15,782)	6,107	(56,935)
Equity in earnings (losses) of affiliates	417,091	(17)	(151)	(417,091)	(168)
Gain (loss) on disposal of assets		594	(60)		534
Interest and other income (expense), net	5,590	3,938	(160)	(6,107)	3,261
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTEREST	370,593	378,618	67,002	(417,091)	399,122
Income tax expense		20,106	6,319		26,425
INCOME BEFORE MINORITY INTERESTS	370,593	358,512	60,683	(417,091)	372,697
Minority interests		(1,349)	(755)		(2,104)
NET INCOME	$ 370,593	$ 357,163	$ 59,928	$ (417,091)	$ 370,593

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the six months ended February 28, 2007

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Propane Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY OPERATING ACTIVITIES	$ 275,764	$ 570,542	$ 78,899	$ 44,669	$ (351,979)	$ 617,895
CASH FLOWS FROM INVESTING ACTIVITIES:						
Cash paid for acquisitions, net of cash acquired	(5,535)	(70,670)	(713)	(9,553)	3,386	(83,085)
Capital expenditures		(491,654)	(6,609)	(44,667)		(542,930)
Advances to and investment in affiliates	(1,051,237)			(3,160)	100,000	(954,397)
Proceeds from the sale of assets		9,755	1,662	7,783		19,200
Net cash used in investing activities	(1,056,772)	(552,569)	(5,660)	(49,597)	103,386	(1,561,212)
CASH FLOWS FROM FINANCING ACTIVITIES:						
Proceeds from borrowings	2,392,796		1,489	98,745		2,493,030
Principal payments on debt	(1,991,665)	(10,643)	(473)	(425,711)		(2,428,492)
Proceeds from borrowings from affiliates	2,216,939	2,348,571	91,632	318,965	(4,976,107)	
Payments on borrowings from affiliates	(2,759,168)	(2,092,431)	(87,893)	(36,615)	4,976,107	
Net proceeds from issuance of Common Units	1,200,000					1,200,000
Capital contribution from General Partner	24,489			100,000	(100,000)	24,489
Distributions to parent		(263,470)	(59,510)	(22,757)	345,737	
Distributions to partners	(292,468)				6,242	(286,226)
Debt issuance costs	(8,933)			(518)		(9,451)
Net cash provided by (used in) financing activities	781,990	(17,973)	(54,755)	32,109	251,979	993,350
INCREASE IN CASH AND CASH EQUIVALENTS	982		18,484	27,181	3,386	50,033
CASH AND CASH EQUIVALENTS, beginning of period	728		2,182	26,517	(3,386)	26,041
CASH AND CASH EQUIVALENTS, end of period	$ 1,710	$	$ 20,666	$ 53,698	$	$ 76,074

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ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

UNAUDITED CONDENSED CONSOLIDATING STATEMENTS OF CASH FLOWS

For the six months ended February 28, 2006

(In thousands)

	Parent	Midstream Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
NET CASH FLOWS PROVIDED BY (USED IN) OPERATING ACTIVITIES	$ (49,672)	$ 446,704	$ 41,026	$	$ 438,058
CASH FLOWS FROM INVESTING ACTIVITIES:					
Cash paid for acquisitions, net of cash acquired		(17,124)	(12,822)		(29,946)
Working capital settlement on prior year acquisitions		19,653			19,653
Capital invested in subsidiaries	(132,387)			132,387	
Capital expenditures		(229,751)	(25,350)		(255,101)
Proceeds from the sale of assets		2,412	1,463		3,875
Net cash used in investing activities	(132,387)	(224,810)	(36,709)	132,387	(261,519)
CASH FLOWS FROM FINANCING ACTIVITIES:					
Proceeds from borrowings	824,192		188,996		1,013,188
Proceeds from short term borrowings from affiliates	883,307	729,390		(1,612,697)	
Principal payments on debt	(925,192)		(243,130)		(1,168,322)
Principal payments received from affiliates	(729,390)	(883,307)		1,612,697	
Distributions to parent	(4,193)	(125,402)	(18,812)	148,407	
Distributions from subsidiaries	144,214		4,193	(148,407)	
Debt issuance costs	(1,196)				(1,196)
Equity offering	132,387				132,387
Capital contribution from general partner	2,702	57,387	75,000	(132,387)	2,702
Unit distributions	(146,369)				(146,369)
Net cash provided by (used in) financing activities	180,462	(221,932)	6,247	(132,387)	(167,610)
INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(1,597)	(38)	10,564		8,929
CASH AND CASH EQUIVALENTS, beginning of period	3,810	38	21,066		24,914
CASH AND CASH EQUIVALENTS, end of period	$ 2,213	$	$ 31,630	$	$ 33,843

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19. REPORTABLE SEGMENTS:

As of February 28, 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 February 28, 2007 include the interstate operations for the entire period. However, the three and six 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 and Oklahoma, 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 from excess gas retained.

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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 six months ended February 28, 2007 were approximately $1,700 to midstream, $1,500 to interstate transportation and $2,500 to propane, for a total of approximately $5,700.

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

	Three Months Ended		Six Months Ended	
	February 28,		February 28,	
	2007	2006	2007	2006
Volumes:				
Midstream				
Natural gas MMBtu/d sold	819,611	1,529,856	900,238	1,528,616
NGLs bbls/d sold	15,901	9,537	13,723	9,879
Transportation and storage				
Natural gas MMBtu/d transported	5,030,631	4,231,797	4,918,191	4,349,137
Natural gas MMBtu/d sold	1,655,278	1,868,486	1,481,724	1,709,049
Interstate transportation				
Natural gas MMBtu/d transported	1,728,056		1,728,056	
Propane gallons (in thousands)				
Retail	253,715	165,758	394,346	254,496
Wholesale	32,428	28,243	55,711	47,844
Total gallons	286,143	194,001	450,057	302,340

	Three Months Ended		Six Months Ended	
	February 28,		February 28,	
	2007	2006	2007	2006
Revenues:				
Midstream	$ 624,245	$ 1,205,027	$ 1,232,428	$ 2,754,855
Eliminations	(297,620)	(611,989)	(654,212)	(1,518,793)
Intrastate transportation and storage	1,108,055	1,490,265	1,918,908	3,055,775
Interstate transportation (see Note 3)	58,158		58,158	
Retail propane and other propane related	529,555	332,147	824,794	514,178
Wholesale propane	39,209	32,958	68,246	56,899
Other	878	1,408	2,603	3,522
Total revenues	$ 2,062,480	$ 2,449,816	$ 3,450,925	$ 4,866,436
Cost of Sales:				
Midstream	$ 573,712	$ 1,160,557	$ 1,132,430	$ 2,597,427
Eliminations	(297,620)	(611,989)	(654,212)	(1,518,793)
Intrastate transportation and storage	862,617	1,236,485	1,544,474	2,665,788
Retail propane and other propane related	311,364	193,845	486,714	302,315
Wholesale propane	35,684	29,426	63,225	51,711

Other	59	507	528	1,010
Total cost of sales	$ 1,485,816	$ 2,008,831	$ 2,573,159	$ 4,099,458

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	Three Months Ended February 28, 2007	Three Months Ended February 28, 2006	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006
Depreciation and Amortization:				
Midstream	$ 5,565	$ 3,880	$ 10,184	$ 7,565
Intrastate transportation and storage	12,013	11,061	24,310	20,795
Interstate transportation	9,654		9,654	
Retail propane and other propane related	17,937	13,744	34,528	26,954
Wholesale propane	191	223	368	407
Other		106	125	206
Total depreciation and amortization	$ 45,360	$ 29,014	$ 79,169	$ 55,927

	Three Months Ended February 28, 2007	Three Months Ended February 28, 2006	Six Months Ended February 28, 2007	Six Months Ended February 28, 2006
Operating Income (Loss):				
Midstream	$ 25,048	$ 26,856	$ 56,618	$ 120,864
Intrastate transportation and storage	182,815	188,158	244,614	257,431
Interstate transportation	34,112		34,112	
Retail propane and other propane related	114,314	70,255	132,172	80,734
Wholesale propane	1,247	1,825	1,545	2,207
Other	419	(68)	373	220
Selling general and administrative expenses not allocated to segments	407	(6,206)	(3,230)	(9,026)
Total operating income	358,362	280,820	466,204	452,430
Other items not allocated by segment:				
Interest expense	(40,772)	(28,542)	(82,234)	(56,935)
Equity in earnings (losses) of affiliates	(514)	106	4,373	(168)
Gain (loss) on disposal of assets	(3,229)	662	(1,285)	534
Interest and other income, net	1,423	2,302	3,094	3,261
Income tax expense	(3,300)	(4,014)	(6,896)	(26,425)
Minority interests	(856)	(549)	(1,110)	(2,104)
	(47,248)	(30,035)	(84,058)	(81,837)
Net income	$ 311,114	$ 250,785	$ 382,146	$ 370,593

	2007	2006
Additions to Property, Plant and Equipment, including acquisitions (accrual basis):		
Midstream	$ 114,005	$ 10,245
Intrastate transportation and storage	456,785	235,391
Interstate transportation	1,269,051	
Retail propane and other propane related	44,503	32,554
Wholesale propane	30	298
Other	839	1,973
Total	$ 1,885,213	$ 280,461

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	February 28, 2007	August 31, 2006
Total Assets:		
Midstream	$ 642,660	$ 682,652
Intrastate transportation and storage	3,235,382	3,029,124
Interstate transportation	1,554,586	
Retail propane and other propane related	1,727,385	1,619,732
Wholesale propane	37,009	39,816
Other	99,293	83,689
Total	$ 7,296,315	$ 5,455,013

20. SUBSEQUENT EVENTS:

In March 2007 the Partnership entered into interest rate swaps with an aggregate notional amount of $600,000 with various financial institutions in anticipation of a debt offering in the fourth fiscal quarter of 2007.

On May 1, 2007, the Partnership will hold a special meeting of its Common Unitholders, entitled to vote as of the record date of April 2, 2007, to approve (i) a change in the terms of the Partnership s Class G Units to provide that each Class G Unit is convertible into one Common Unit and (ii) the issuance of additional Common Units upon such conversion.

The conversion of these Class G Units would be on a one-to-one basis, resulting in a greater number of Common Units outstanding, but not an increase in the overall number of ETP units. Accordingly, on an overall basis, the conversion would not be dilutive to the Partnership s existing Common Unitholders. The Board of Directors has recommended that the Partnership s Common Unitholders approve these matters.

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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 and Louisiana, and three natural gas storage facilities located in Texas. These assets include approximately 12,200 miles of intrastate pipeline in service, with an additional 500 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 78 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 pipelines. The operating results for Transwestern are included in our results on a consolidated basis as of the acquisition date (December 1, 2006).

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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, Oklahoma, 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 Permin 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 been determined not 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 442 customer service locations in 41 states.

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 plans that we expect to complete in fiscal year 2007, 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 (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. Our total acquisition cost for Transwestern, including assumed debt, was approximately $1.537 billion, including our basis of $956.3 million in CCEH (see Note 3 to the condensed consolidated financial statements).

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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 the Midcontinent Express Pipeline (MEP). The approximately 500-mile 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 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 up to 500,000 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 previously announced 36-inch pipeline extending from the Barnett Shale and interconnecting 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 Partnerships 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 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 October 31, 2006, in Docket No. RP06-614 the FERC issued its Order Accepting and Suspending Tariff Sheets Subject to Refund and Establishing a Hearing and Technical Conference (Commission s October 31, 2006 Order). In this Order the Commission accepted and suspended the revised tariff sheets for the maximum five-month statutory period to be effective April 1, 2007, subject to refund, and subject to the outcome of a hearing established by this order. Transwestern and the active parties in this proceeding, engaged in settlement negotiations to resolve all issues set for hearing by the Commission s October 31, 2006 Order. On March 9, 2007, Transwestern filed with the FERC its Stipulation and Agreement of Settlement (Stipulation and Agreement) which, if approved by the commission, will settle these matters. The Stipulation 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.

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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 February 28, 2007 (see Note 3 to the condensed consolidated financial statements). The increase from August 31, 2006 to February 28, 2007 in our long-term debt was also due to the Transwestern acquisition.

Operating Data

Comparative Results for the Three and Six Months Ended February 28, 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 February 28,		Increase	Six Months Ended February 28,		Increase
	2007	2006	(Decrease)	2007	2006	(Decrease)
Natural gas MMBtu/d	819,611	1,529,856	(710,245)	900,238	1,528,616	(628,378)
NGLs Bbls/d	15,901	9,537	6,364	13,723	9,879	3,844

For the three months ended February 28, 2007, the decrease in natural gas volumes 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 favorable market conditions to process and extract NGLs during the three months ended February 28, 2007 compared to the same period last year and the completion of our Johnson County processing plants during the 2007 fiscal period.

For the six months ended February 28, 2007, the decrease in natural gas volumes was principally due to less favorable market conditions during the fiscal 2007 period. The increase in NGL sales volumes is principally due to favorable market conditions to process and extract NGLs during the 2007 fiscal period compared to the same period last year and the completion of our Johnson County processing plants in the 2007 fiscal period.

Intrastate Transportation and Storage

	Three Months Ended February 28,		Increase	Six Months Ended February 28,		Increase
	2007	2006	(Decrease)	2007	2006	(Decrease)
Natural gas MMBtu/d -transported	5,030,631	4,231,797	798,834	4,918,191	4,349,137	569,054
Natural gas MMBtu/d -sold	1,655,278	1,868,486	(213,208)	1,481,724	1,709,049	(227,325)

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For the three months ended February 28, 2007, transported natural gas volumes increased principally due to the increased volumes experienced on the ET Fuel system and East Texas Pipeline system as a result of the continued efforts to secure long-term shipper contracts and the completion of phase I of the 42-inch pipeline project in late August 2006 and phase II in December 2006. Natural gas sales volumes on the HPL System for the three months ended February 28, 2007 decreased principally due to less volumes sold to east Texas markets as a result of lower price differentials.

For the six months ended February 28, 2007, transported natural gas volumes increased due to the increased volumes transported on the ET Fuel System and East Texas Pipeline system as a result of our continued efforts to secure more long-term shipper contracts and the completion of phase I and II of the 42-inch pipeline project. Natural gas sales volumes on the HPL System for the six months ended February 28, 2007 decreased principally due to less volumes sold to east Texas markets as a result of lower price differentials.

Interstate Transportation

	Three Months Ended February 28,			Six Months Ended February 28,		
	2007	2006	Increase	2007	2006	Increase
Natural gas MMBtu/d -transported	1,728,056		1,728,056	1,728,056		1,728,056

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

Propane

	Three Months Ended February 28,			Six Months Ended February 28,		
	2007	2006	Increase	2007	2006	Increase
Propane gallons sold						
(in thousands)						
Retail	253,715	165,758	87,957	394,346	254,496	139,850
Wholesale	32,428	28,243	4,185	55,711	47,844	7,867

Retail Propane. The retail propane operations continue to reflect significant increases in gallons sold in the three and six months ended February 28, 2007 as compared to the three and six months ended February 28, 2006 due to the Titan acquisition in June 2006. Synergies and blending operations have taken place over the course of the past six months with this acquisition to gain efficiencies and cost savings. Titan locations that are identifiable as operating on a stand-alone basis contributed 71.8 million and 112.9 million of the net gallon increase in retail propane gallons sold for the three and six months ended February 28, 2007, respectively, compared to the three and six months ended February 28, 2006. The remainder of the increased volumes is attributed to the increased volumes in the blended locations from the Titan acquisition, other acquisition related volumes, colder weather experienced during the second quarter and to a lesser extent, internal growth. The overall weather in our areas of operations during the three months ended February 28, 2007 was 4.8% colder than the three months ended February 28, 2006 and 4.7% warmer than normal. For the six months ended February 28, 2007, weather was 6.8% colder than the six months ended February 28, 2006 and 4.4% warmer than normal. Our diversified West to East operations throughout the United States allows us to help balance weather patterns capturing the favorable heating degree days as the colder weather travels across the country.

Wholesale Propane. For the three months ended February 28, 2007, sales of wholesale propane gallons increased by 4.2 million gallons compared to the three months ended February 28, 2006. The increase is due to an increase of 5.3 million gallons in our Canadian wholesale operations related to increased marketing efforts in our Canadian operations, offset by a decrease of 1.1 million gallons sold in our U.S. wholesale operations.

For the six months ended February 28, 2007, wholesale propane gallons increased by 7.9 million gallons compared to the same period in 2006. Of this increase, 10.4 million is due to an increase in gallons sold in our foreign wholesale operations related to increased marketing efforts, offset by a 2.5 million gallon decrease in our U.S. wholesale operations.

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Results of Operations

Consolidated Results

	Three Months Ended February 28, 2007	2006	Change	Six Months Ended February 28, 2007	2006	Change
Revenues	$ 2,062,480	$ 2,449,816	$ (387,336)	$ 3,450,925	$ 4,866,436	$ (1,415,511)
Cost of sales	1,485,816	2,008,831	(523,015)	2,573,159	4,099,458	(1,526,299)
Gross margin	576,664	440,985	135,679	877,766	766,978	110,788
Operating expenses	133,809	99,696	34,113	266,190	202,367	63,823
Selling, general and administrative	39,133	31,455	7,678	66,203	56,254	9,949
Depreciation and amortization	45,360	29,014	16,346	79,169	55,927	23,242
Consolidated operating income	358,362	280,820	77,542	466,204	452,430	13,774
Interest expense	(40,772)	(28,542)	(12,230)	(82,234)	(56,935)	(25,299)
Equity in earnings (losses) of affiliates	(514)	106	(620)	4,373	(168)	4,541
Gain (loss) on disposal of assets	(3,229)	662	(3,891)	(1,285)	534	(1,819)
Interest and other income, net	1,423	2,302	(879)	3,094	3,261	(167)
Income tax expense	(3,300)	(4,014)	714	(6,896)	(26,425)	19,529
Minority interests	(856)	(549)	(307)	(1,110)	(2,104)	994
Net income	$ 311,114	$ 250,785	$ 60,329	$ 382,146	$ 370,593	$ 11,553

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

Interest Expense. For the three months ended February 28, 2007 compared to the three months ended February 28, 2006, interest expense increased principally due to a net $11.6 million increase in interest expense related to increased borrowings on the Partnership s Senior Notes and Revolving Credit Facility, offset by a decrease of $2.7 million related to interest rate swaps. The increased borrowings were a result of the CCEH and Titan acquisitions. Interest related to debt of Transwestern represents $5.1 million of the increased interest expense during the three months ended February 28, 2007. Propane related interest decreased $2.2 million due primarily to the scheduled debt payments that have occurred between the three month periods.

For the six months ended February 28, 2007 compared to the six months ended February 28, 2006, interest expense increased principally due to a net $21.1 million increase in interest expense related to increased borrowings on the Partnership s Senior Notes and Revolving Credit Facility, and a net increase of $1.0 million related to interest rate swaps. The increased borrowings were a result of the CCEH and Titan acquisitions. Interest related to debt of Transwestern represents $5.1 million of the increased interest expense. Propane related interest decreased $2.2 million due primarily to the scheduled debt payments that have occurred between the six month periods.

Equity in Earnings (Losses) of Affiliates. The increased loss in equity in earnings (losses) of affiliates for the three months ended February 28, 2007 compared to the three months ended February 28, 2006 was due to increased losses from our ownership of a joint venture that was terminated February 28, 2007.

The increase in equity in earnings (losses) of affiliates for the six months ended February 28, 2007 compared to the six months ended February 28, 2006 was due primarily to 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 February 28, 2007 was principally due to the sale of a compressor station in February 2007.

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 decreased expense for the three and six months ended February 28, 2007 was attributed principally to higher income from trading gains recognized by a taxable subsidiary during the periods ended February 28, 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.

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Three and Six Month Operating Results by Segment

Midstream

	Three Months Ended February 28, 2007	2006	Change	Six Months Ended February 28, 2007	2006	Change
Revenues	$ 624,245	$ 1,205,027	$ (580,782)	$ 1,232,428	$ 2,754,855	$ (1,522,427)
Cost of sales	573,712	1,160,557	(586,845)	1,132,430	2,597,427	(1,464,997)
Gross margin	50,533	44,470	6,063	99,998	157,428	(57,430)
Operating expenses	8,906	7,104	1,802	17,793	14,342	3,451
Selling, general and administrative	11,014	6,630	4,384	15,403	14,657	746
Depreciation and amortization	5,565	3,880	1,685	10,184	7,565	2,619
Segment operating income	$ 25,048	$ 26,856	$ (1,808)	$ 56,618	$ 120,864	$ (64,246)

Gross Margin. For the three months ended February 28, 2007, midstream s gross margin increased as a result of the following factors:

Increase in processing margin and fee-based revenue from our gathering assets. The increase was due to increased volumes from the completion of our Johnson County plant in the first quarter of 2007, the acquisition of two gathering systems in North Texas during the first fiscal quarter of 2007 and one in the second fiscal quarter of 2007, and favorable processing conditions during the second fiscal quarter of 2007 compared to the same period last year.

Decrease in non-trading margin from our marketing activities. Market conditions, including lower basis differentials between the west and east Texas markets during the fiscal 2007 period, resulted in lower sales volumes conducted by our producer services operations. Included in this decrease was a $3.7 million decrease in non-trading mark-to-market gains resulting from market price fluctuations on open derivative positions at February 28, 2007 compared to February 28, 2006.

For the six months ended February 28, 2007, midstream s gross margin decreased by $57.4 million primarily due to the following factors:

Decrease in net trading revenues. During the fiscal 2006 period we recognized trading gains resulting from market anomalies created by the hurricanes that struck Texas and Louisiana in August and September 2005. There were no significant weather anomalies during the six months ended February 28, 2007.

Decrease in non-trading margin from our marketing activities. Market conditions, including lower basis differentials between the west and east Texas markets, resulted in lower sales volumes conducted by our producer services operations. Included in this decrease was a $19.6 million decrease in non-trading mark-to-market gains due to fewer open positions and lower average prices in 2007 as compared to 2006.

Increase in processing margin and fee-based revenue. The increase was due to favorable processing conditions, the completion of our Johnson County plant in the first quarter of 2007, and the acquisition of two gathering systems in North Texas in the first fiscal quarter of 2007 and one in the second fiscal quarter of 2007.

Operating Expenses. Midstream operating expenses increased $1.8 million for the three months ended February 28, 2007 compared to the same period ended February 28, 2006. The increase was primarily driven by increased compressor rentals of $0.8 million, increased pipeline and compressor maintenance of $0.5 million, and increased employee-related costs, such as salaries, incentive compensation and healthcare costs, of

$0.5 million.

Midstream operating expenses increased $3.5 million for the six months ended February 28, 2007 compared to the same period ended February 28, 2006. The increase was primarily driven by increased compressor rental expense of $1.6 million, increased pipeline and compressor maintenance of $1.0 million and increased employee-related costs, such as salaries, incentive compensation and healthcare costs, of $0.9 million.

Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses for the three months ended February 28, 2007 increased $4.4 million compared to the three months ended February 28, 2006. The increase was attributable to $4.4 million of legal costs associated with the regulatory inquiries. In addition, effective with the Transwestern acquisition on December 1, 2006, administrative expenses are now allocated to the operating partnerships. This resulted in an allocation of $1.7 million in administrative expenses which previously had not been allocated. There also was a $1.0 million increase in employee-related costs such as salaries, incentive

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compensation and healthcare costs. These increases were offset by a $0.9 million increase in overhead costs capitalized to capital expansion projects, a $0.5 million decrease of allocated overhead due to more corporate overhead being allocated to the transportation segment, and a $1.3 million decrease in other general and administrative expenses. 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 six months ended February 28, 2007 increased $0.8 million compared to the six months ended February 28, 2006. The increase was attributable to $4.4 million of legal costs associated with regulatory inquiries, a $1.7 million allocation of administrative expenses for overhead costs which previously had not been allocated, and increases of $1.2 million in employee-related costs such as salaries, incentive compensation and healthcare costs. The increase was offset by increases of $1.8 million in departmental costs allocated to the transportation and storage operating segment, an increase of $1.3 million in overhead costs capitalized to capital expansion projects, a one-time $0.9 million reimbursement of administrative costs related to the North Side Loop pipeline project from the project partner, and a $2.5 million decrease in other general and administrative expenses.

Depreciation and Amortization. Midstream depreciation and amortization expense increased $1.7 million for the three months ended February 28, 2007 compared to the same three month period in 2006 principally due to additions to property and equipment subsequent to February 28, 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 $2.6 million for the six months ended February 28, 2007 compared to the same six month period in 2006 is principally due to additions to property and equipment subsequent to February 28, 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 February 28,			Six Months Ended February 28,		
	2007	**2006**	**Change**	**2007**	**2006**	**Change**
Revenues	$ 1,108,055	$ 1,490,265	$ (382,210)	$ 1,918,908	$ 3,055,775	$ (1,136,867)
Cost of sales	862,617	1,236,485	(373,868)	1,544,474	2,665,788	(1,121,314)
Gross margin	245,438	253,780	(8,342)	374,434	389,987	(15,553)
Operating expenses	37,341	41,809	(4,468)	80,139	88,249	(8,110)
Selling, general and administrative	13,269	12,752	517	25,371	23,512	1,859
Depreciation and amortization	12,013	11,061	952	24,310	20,795	3,515
Segment operating income	$ 182,815	$ 188,158	$ (5,343)	$ 244,614	$ 257,431	$ (12,817)

Gross Margin. For the three months ended February 28, 2007 as compared to three months ended February 28, 2006, intrastate transportation and storage gross margin decreased by $8.3 million, principally due to the following:

Volumes. Although low price differentials between the Waha and Katy market hubs decreased demand for West-to-East transport business, overall volumes on our transportation pipelines were higher during the second fiscal quarter compared to the same period last year due to continued efforts to secure long-term shipper contracts, a colder winter in fiscal 2007 and the completion of Phase I and II of the 42-inch pipeline. We expect our volumes to continue to increase during the next six months of our fiscal year due to the completion of the last phase of our 42-inch pipeline project in March 2007, the completion of various growth projects during the second fiscal quarter of 2007 and the demand for natural gas during the summer months to supply natural gas to electric generating power plants.

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 $9.00/MMBtu during the three months ended February 28, 2006 to $6.00 to $7.00/MMBtu during the same period this year resulting in lower revenue.

Margin decrease on HPL. HPL s margin decreased between the two periods principally due to a $66.9 million decrease in gains from the discontinuation of hedge accounting resulting from our determination

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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 $84.7 million during the quarter ended February 28, 2006 and approximately $17.8 million during the same period in 2007. This decrease was offset by an increase in margin related to additional sales of natural gas from our storage facility of 6.4 Bcf due to colder temperatures during the second quarter of 2007 and improved optimization of the pipeline assets.

For the six months ended February 28, 2007 as compared to the six months ended February 28, 2006, intrastate transportation and storage gross margin decreased by $15.5 million, principally due to the following:

Volumes. Although low price differentials between the Waha and Katy market hubs decreased demand for West-to-East transport business, overall volumes on our transportation pipelines were higher during the 2007 fiscal period compared to the same period last year due to continued efforts to secure long-term shipper contracts, a colder winter in fiscal 2007 and the completion of Phase I and II of the 42-inch pipeline. We expect our volumes to continue to increase during the next six months of our fiscal year due to the completion of the last phase of our 42-inch pipeline project in March 2007, the completion of various growth projects during the second fiscal quarter of 2007 and the demand for natural gas during the summer months to supply natural gas to electric generating power plants.

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 six months ended February 28, 2006 to $4.00 to $7.00/MMBtu during the same period this year resulting in lower revenue.

Margin decrease on HPL. HPL s margin decreased $6.4 million between the two periods primarily due to a $66.9 million decrease in gains from the discontinuation of hedge accounting, approximately $18 million in increased margin on gas sold from our Bammel facility and delivered to a customer in September 2005, and lower margins on gas sales due primarily to lower volumes and lower natural gas prices. These decreases were offset by a significant loss on settled derivatives during the fiscal 2006 period.

Operating Expenses. Intrastate transportation and storage operating expenses decreased $4.4 million when comparing the three months ended February 28, 2007 to the corresponding three month period in 2006. The decrease was primarily attributable to a decrease of $8.5 million in fuel consumption and $1.2 million of cost savings as a result of the EMS contract buyout during the three months ended November 30, 2006 offset by increases of $1.7 million in compressor rental expense, $2.0 million in pipeline maintenance, $0.5 million in property taxes, and $1.0 million in other operating expenses.

Intrastate transportation and storage operating expenses decreased $8.1 million when comparing the six months ended February 28, 2007 to the same prior period ended February 28, 2006. The decrease was principally attributable to a decrease of $16.8 million in fuel consumption and a decrease of $2.0 million in compressor maintenance expense. These decreases were offset by increases of $3.7 million in compressor rentals, $2.4 million in property taxes, $2.3 million in pipeline maintenance, and $1.1 million in employee-related costs such as salaries, incentive compensation and healthcare costs.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased $0.5 million for the three months ended February 28, 2007 compared to the three months ended February 28, 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.

Intrastate transportation and storage general and administrative expenses increased $1.9 million for the six months ended February 28, 2007 compared to the six months ended February 28, 2006 principally due to an increase in certain departmental costs allocated from the midstream segment. The increase in allocated departmental costs is due to the increase in employee headcount resulting primarily from the HPL acquisition.

Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased $1.0 million for the three months ended February 28, 2007 compared to the three months ended February 28, 2006, principally due to additions to property and equipment subsequent to February 28, 2006 offset by $1.1 million of depreciation expense recorded in second fiscal quarter of 2006 for a purchase price allocation related to HPL.

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Intrastate transportation and storage depreciation and amortization expense increased $3.5 million from the six months ended February 28, 2006 to the six months ended February 28, 2007. The increase was principally due to additions to property and equipment subsequent to February 28, 2006 offset by $1.1 million of depreciation expense recorded in second fiscal quarter of 2006 for a purchase price allocation related to HPL.

Interstate Transportation

	Three Months Ended February 28,			Six Months Ended February 28,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 58,158	$	$ 58,158	$ 58,158	$	$ 58,158
Operating expenses	8,521		8,521	8,521		8,521
Selling, general and administrative	5,871		5,871	5,871		5,871
Depreciation and amortization	9,654		9,654	9,654		9,654
Segment operating income	$ 34,112	$	$ 34,112	$ 34,112	$	$ 34,112

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

Retail Propane

	Three Months Ended February 28,			Six Months Ended February 28,		
	2007	2006	Change	2007	2006	Change
Retail propane revenues	$ 499,252	$ 312,227	$ 187,025	$ 765,342	$ 474,420	$ 290,922
Other propane related revenues	30,303	19,920	10,383	59,452	39,758	19,694
Retail propane cost of sales	304,634	188,679	115,955	472,253	291,061	181,192
Other propane related cost of sales	6,730	5,166	1,564	14,461	11,254	3,207
Gross margin	218,191	138,302	79,889	338,080	211,863	126,217
Operating expenses	77,346	49,004	28,342	156,334	96,087	60,247
Selling, general and administrative	8,594	5,299	3,295	15,046	8,088	6,958
Depreciation and amortization	17,937	13,744	4,193	34,528	26,954	7,574
Segment operating income	$ 114,314	$ 70,255	$ 44,059	$ 132,172	$ 80,734	$ 51,438

Revenues. Of the total increase in retail propane revenue of $187.0 million between the three months ended February 28, 2007 and 2006, $143.8 million is due to the increase in volumes sold by customer service locations added through the identifiable Titan locations. Revenues also increased in relation to the increased volumes from the blended locations as discussed above, the increase in volumes sold by customer service locations added through other propane acquisitions and, to a lesser extent, higher selling prices over the same period last year. Other propane related revenues increased $10.4 million for the three months ended February 28, 2007 compared to 2006 of which $6.6 million is due to the Titan acquisition in June, 2006 and $3.8 million is due to other propane acquisitions and enhanced fee generating programs in servicing customers.

Of the total increase in retail propane revenue of $290.9 million between the six months ended February 28, 2007 and 2006, $221.9 million is due to the increase in volumes sold by customer service locations added through the identifiable Titan locations. The remaining increase of $69.0 million is due to higher selling prices to retain margin during times of rising fuel costs and from the volumes related to other acquisitions and internal growth. Other propane related revenues increased $19.7 million for the six months ended February 28, 2007 compared to the same six-month period last year primarily due to an increase of $13.2 million from other propane related revenues from the identifiable Titan locations. The remaining increase of $6.5 million in other propane related revenues is due to other propane acquisitions and enhanced fee generating programs in servicing customers.

Costs of Sales. During the three months ended February 28, 2007 compared to the three months ended February 28, 2006, retail propane cost of sales increased by $116.0 million of which $86.1 million is a result of an overall increase in the cost of sales related to the gallons sold by the identifiable 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 quarter ended February 28, 2007 as compared to the quarter ended February 28, 2006.

During the six months ended February 28, 2007 compared to the six months ended February 28, 2006, retail propane cost of sales increased by $181.2 million of which $137.4 million is a result of an overall increase in the cost of sales related to the gallons sold by the identifiable customer service locations added through the Titan acquisition, and $43.8 million is due to higher cost of fuel and the other increase in volumes sold as described above.

Gross Margin. The overall increase in gross margins for the three and six-month comparable periods ended February 28, 2007 and 2006 is primarily related to the Titan acquisition in June 2006. The propane margin remained strong during the six months ended February 28, 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 six months ended February 28, 2007, operating expenses increased by $28.3 million and $60.2 million, respectively, compared to the same three and six month periods last year. These increases were due to a $23.7 million and $45.8 million increase for the three and six months ended February 28, 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, enhancements to our IT infrastructure, and other acquisition related costs.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses for the comparable three and six-month periods of February 28, 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. 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 $2.5 million for the three and six months ended February 28, 2007.

Depreciation and Amortization Expense. The increase in depreciation and amortization expense for the three and six months ended February 28, 2007 as compared to 2006 is due primarily to the acquisition of Titan on June 1, 2006.

Wholesale Propane

	Three Months Ended February 28,			Six Months Ended February 28,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 39,209	$ 32,958	$ 6,251	$ 68,246	$ 56,899	$ 11,347
Cost of sales	35,684	29,426	6,258	63,225	51,711	11,514
Gross margin	3,525	3,532	(7)	5,021	5,188	(167)
Operating expenses	1,295	916	379	1,826	1,603	223
Selling, general and administrative	792	568	224	1,282	971	311
Depreciation and amortization	191	223	(32)	368	407	(39)
Segment operating income	$ 1,247	$ 1,825	$ (578)	$ 1,545	$ 2,207	$ (662)

Revenues. Of the $6.3 million increase in wholesale revenue for the three months ended February 28, 2007 compared to the same three months in 2006, $8.2 million is related to the increase in gallons sold to new customers in our eastern wholesale and Canadian operations and increased selling prices, offset by a decrease in the U.S. wholesale revenues due to decrease volumes.

Of the increase of $11.3 million in wholesale revenue from the six months ended February 28, 2007 compared to the same six month period last year, $15.2 million is primarily related to the increase in gallons sold to new customers in our eastern wholesale and Canadian operations and increased selling prices, offset by a decrease of $3.8 million in our U.S. wholesale operations.

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Costs of Sales. For the three and six months ended February 28, 2007 compared to the corresponding three and six months ended February 28, 2006, total cost of sales increased by $6.3 million and $11.5 million, respectively. Foreign wholesale cost of sales increased $7.3 million and $14.1 million for the three and six months ended February 28, 2007 due to the increased volumes sold and to a lesser extent due to the increase in fuel cost per gallon sold. These increases were offset by a decrease in the cost of sales in the U.S. wholesale of $1.0 million and $2.6 million for the three and six months ended February 28, 2007 as compared to the three and six months ended February 28, 2006.

Gross Margin. The overall gross margin in the wholesale operations for the three and six months ended February 28, 2007 as compared to the three and six months ended February 28, 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 February 28,			Six Months Ended February 28,		
	2007	2006	Change	2007	2006	Change
Revenues	$ 878	$ 1,408	$ (530)	$ 2,603	$ 3,522	$ (919)
Cost of sales	59	507	(448)	528	1,010	(482)
Operating expenses	400	863	(463)	1,577	2,086	(509)
Depreciation and amortization		106	(106)	125	206	(81)
Other operating income (loss)	$ 419	$ (68)	$ 487	$ 373	$ 220	$ 153
Unallocated selling, general and administrative expenses	$ (407)	$ 6,206	$ (6,613)	$ 3,230	$ 9,026	$ (5,796)

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 six months ended February 28, 2007, a net $5.7 million was allocated to the operating partnerships, which constituted the decrease in total unallocated selling general and administrative expenses from the three and six month periods ended February 28, 2006.

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 six months ended February 28, 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 February 28,		Six Months Ended February 28,	
	2007	2006	2007	2006
Federal statutory tax rate	35.0%	35.0%	35.0%	35.0%
State income tax rate net of federal benefit	0.7%	3.4%	0.7%	3.4%
Earnings not subject to tax at the Partnership level	(34.7)%	(36.8)%	(33.9)%	(31.8)%
Effective tax rate	1.0%	1.6%	1.8%	6.6%

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

	Three Months Ended February 28,		Six Months Ended February 28,	
	2007	2006	2007	2006
Current provision:				
Federal	$ 3,336	$ 12,853	$ 6,487	$ 28,117
State	2,487	950	2,826	1,288
Deferred benefit:				
Federal	(2,247)	(9,288)	(2,178)	(2,625)
State	(276)	(501)	(239)	(355)
Total income tax expense	$ 3,300	$ 4,014	$ 6,896	$ 26,425

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

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 six months ended February 28, 2007, we recognized current state income tax expense related to the Texas margin tax of $1.8 million. There is no comparable state tax expense for the periods ended February 28, 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 $37.3 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 $5.6 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 $773.3 million for the remainder of the fiscal year, including $204.3 million related to Transwestern; and customer propane tanks for which we expect to expend approximately $8.5 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.

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On October 3, 2006, we entered into a long-term agreement with CenterPoint Energy Resources Corp (CenterPoint) to provide the natural gas utility with firm transportation and storage services on our HPL System located along the Texas gulf coast region. Under the terms of this agreement, 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 agreement 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. This agreement went into effect beginning April 1, 2007.

Cash Flows

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

Operating Activities. Cash provided by operating activities during the six months ended February 28, 2007, was $617.9 million as compared to cash provided by operating activities of $438.1 million for the six months ended February 28, 2006. The net cash provided by operations for the six months ended February 28, 2007 consisted of net income of $382.1 million, non-cash charges of $83.9 million, principally depreciation and amortization, unit based compensation expense, and deferred taxes, and cash from changes in operating assets and liabilities of $151.9 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 transportation and storage operations.

Investing Activities. Cash used in investing activities during the six months ended February 28, 2007 of $1.6 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 $83.1 million and $542.9 million invested for growth capital expenditures and maintenance expenditures needed to sustain operations.

Financing Activities. Cash provided by financing activities was $999.3 million for the six months ended February 28, 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 proceeds of $800.0 million from the issuance of senior notes (see Note 12 to our condensed consolidated financial statements above) of which we used approximately $791.0 million to repay borrowings under the Partnership s revolving credit facility. In January 2007, we borrowed approximately $290.0 million on our Revolving Credit Facility to fund a required pre-payment of the debt we assumed in connection with our acquisition of Transwestern. During the six months ended February 28, 2007, we paid distributions of $286.2 million to our partners.

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 February 28, 2007, we have not made any sales under this Registration Statement.

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Description of Indebtedness

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	(628)
Total long-term debt assumed	$ 519,372

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 $307.0 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.

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. We were in compliance with all our consolidated debt covenants as of February 28, 2007.

Our indebtedness as of February 28, 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.

Energy Transfer Partners Facilities

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 February 28, 2007, there was a balance of $783.8 million in revolving credit loans (including $63.5 million in Swingline loans) and $57.3 million in letters of credit. The weighted average interest rate on the total amount outstanding at February 28, 2007, was 5.979%. The total amount available under the ETP Revolving Credit Facility as of February 28, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $658.9 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.

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 February 28, 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 February 28, 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 February 28, 2007 was $74.0 million.

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 March 26, 2007, we declared a per unit cash distribution of $0.7875 ($3.15 per unit on an annualized basis) for the quarter ended February 28, 2007, which will be paid on April 13, 2007 to Unitholders of record at the close of business on April 6, 2007.

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. 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.

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The following table provides a summary of our commodity-related price risk management assets and liabilities as of February 28, 2007:

February 28, 2007	Commodity	Notional Volume MMBTU	Maturity	Fair Value
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	23,023,316	2007-2009	$ 3,347
Swing Swaps IFERC	Gas	17,592,500	2007-2008	1,275
Fixed Swaps/Futures	Gas	(23,765,000)	2007	25,294
Forward Physical Contracts	Gas	(4,043,550)	2007-2008	(320)
Options	Gas	(602,000)	2007-2008	742
Forward/Swaps in Gallons	Propane	4,452,000	2007	(524)
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(3,880,000)	2007-2008	$ 5,514
Swing Swaps IFERC	Gas	68,200	2007	(6)
Forward Physical Contracts	Gas		2007	(1,141)
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,282,500	2007	$ (174)
Fixed Swaps/Futures	Gas	2,330,000	2007	189

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 February 28, 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	(21,435,000)	$ 25,483	$ 15,862
Basis Swaps IFERC/NYMEX	25,305,816	3,173	597
Swing Swaps IFERC	17,592,500	1,275	242
Options	(602,000)	742	130
Forward Physical Contracts	(4,043,550)	(320)	7,662
Propane Forwards/Swaps (in Gallons)	4,452,000	(524)	442

Trading Derivatives			
Swing Swaps IFERC	68,200	(6)	256
Basic Swaps IFERC/NYMEX	(3,880,000)	5,514	230
Forward Physical Contracts		(1,141)	3,002

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).

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.

We entered into forward starting interest rate swaps with a notional value of $400.0 million during the three months ended August 31, 2006. The fair value of the swaps was recorded as a liability of $15.0 million and $8.7 million on the consolidated balance sheets as of February 28, 2007 and August 31, 2006. A hypothetical change of 1% on the underlying interest rate would have an effect of $31.8 million on the value of the swap as of February 28, 2007. These interest rate swaps were settled subsequent to February 28, 2007 at a cost of approximately $13.4 million.

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 February 28, 2007 and August 31, 2006 was a net liability and asset of $0.4 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 $2.4 million on the value of the swap as of February 28, 2007.

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.

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 February 28, 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 six months ended February 28, 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.

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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, 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.

ITEM 1A. RISK FACTORS

The December 1, 2006 acquisition of Transwestern and operations in the interstate transportation business results in additional risk factors, including the following:

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.

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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.

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, existing 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 may challenge the lawfulness of tariff rates that have become final and effective. The FERC may also investigate such rates absent shipper complaint. 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 capacity and transportation facilities. 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 FERC s ratemaking methodologies may limit our ability to set rates based on our true costs or may delay the use of rates that reflect increased costs.

The potential for a challenge to our tariff rates creates the risk that the FERC might find some of our tariff rates to be in excess of a just and reasonable level that is, a level justified by our cost of service. In such an event, the FERC would order us to reduce any such rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

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, Santa Fe Pacific Pipeline (SFPP), were grandfathered rates under the Energy Policy Act of 1992 and that SFPP s shippers had not demonstrated substantially changed circumstances that would justify modification to those rates. The Court also 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 it rebuttable presumption as to corporate partners marginal tax rate from 35% to 34%. The FERC s *BP West Coast* remand decision, the new tax allowance policy and the December 2005 order have been appealed to the D.C. Circuit. Oral argument was held in December 2006. As a result, the ultimate outcome of these proceedings is not certain and could result in changes to the FERC s treatment of income tax allowances in cost of service, which in turn could reduce the tariff rates we charge for natural gas transportation on our Transwestern interstate pipeline system.

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;

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- 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.

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 $1,000,000 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.

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

Not applicable.

ITEM 5. OTHER INFORMATION

Not applicable.

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.

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	Exhibit Number	Description
(1)	3.1	Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(21)	3.1.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(21)	3.1.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(34)	3.1.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Heritage Propane Partners, L.P.
(35)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of 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.
(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.

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		Exhibit Number	Description
(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.
(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.
(25)	**	10.6.4	2004 Unit Plan.
(26)	**	10.6.5	Form of Grant Agreement.

(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.

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	Exhibit Number	Description
(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.
(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.
(*)	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.
(52)	10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.

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	Exhibit Number	Description
(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.
(*)	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.
(*)	99.1	Energy Transfer Partners GP, L.P. unaudited condensed consolidated Balance Sheet as of February 28, 2007.
(*)	99.2	Energy Transfer Partners, L.L.C. unaudited condensed consolidated Balance Sheet as of February 28, 2007.

* 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.

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(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.

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(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.

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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: April 9, 2007

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