Energy Transfer Partners, L.P.
Form 10-Q
August 11, 2008
Table of Contents

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 June 30, 2008

OR

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

Commission file number 1-11727

ENERGY TRANSFER PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

3738 Oak Lawn Avenue

Dallas, Texas 75219

(Address of principal executive offices and zip code)

(214) 981-0700

(Registrant s telephone number, including area code)

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

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

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

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

At August 7, 2008, the registrant had units outstanding as follows:

Energy Transfer Partners, L.P. 151,796,933 Common Units

Table of Contents

FORM 10-Q

INDEX TO FINANCIAL STATEMENTS

Energy Transfer Partners, L.P. and Subsidiaries

		Page
PART I	**FINANCIAL INFORMATION**	
ITEM 1.	FINANCIAL STATEMENTS (Unaudited)	
Condensed Consolidated Balance Sheets June 30, 2008 and December 31, 2007		1
Condensed Consolidated Statements of Operations Three and Six Months Ended June 30, 2008 and May 31, 2007		3
Condensed Consolidated Statements of Comprehensive Income Three and Six Months Ended June 30, 2008 and May 31, 2007		4
Condensed Consolidated Statement of Partners Capital Six Months Ended June 30, 2008		5
Condensed Consolidated Statements of Cash Flows Six Months Ended June 30, 2008 and May 31, 2007		6
Notes to Condensed Consolidated Financial Statements		7
ITEM 2.	MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	39
ITEM 3.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	53
ITEM 4.	CONTROLS AND PROCEDURES	55
PART II	**OTHER INFORMATION**	
ITEM 1.	LEGAL PROCEEDINGS	55
ITEM 1A.	RISK FACTORS	56
ITEM 2.	UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS	58
ITEM 3.	DEFAULTS UPON SENIOR SECURITIES	58
ITEM 4.	SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS	58
ITEM 5.	OTHER INFORMATION	58
ITEM 6.	EXHIBITS	58
SIGNATURES		65

Table of Contents

Forward-Looking Statements

Certain matters discussed in this report, excluding historical information, as well as some statements by Energy Transfer Partners, L.P. (Energy Transfer Partners or the Partnership) in periodic press releases and some oral statements of Energy Transfer Partners officials during presentations about the Partnership, include certain forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Statements using words such as anticipate, believe, intend, project, plan, continue estimate, forecast, may, will, or similar expressions help identify forward-looking statements. Although the Partnership believes such forward-looking statements are based on reasonable assumptions and current expectations and projections about future events, no assurance can be given that every objective will be reached.

Actual results may differ materially from any results projected, forecasted, estimated or expressed in forward-looking statements since many of the factors that determine these results are subject to uncertainties and risks, difficult to predict, and beyond management s control. For additional discussion of risks, uncertainties and assumptions, see Part II Other Information Item 1A, Risk Factors in this Quarterly Report on Form 10-Q as well as the Partnership s Report on Form 10-K as of August 31, 2007 filed with the Securities and Exchange Commission on October 30, 2007.

Definitions

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

/d	per day
Bbls	barrels
Btu	British thermal unit, an energy measurement
Capacity	Capacity of a pipeline, processing plant or storage facility refers to the maximum capacity under normal operating conditions and, with respect to pipeline transportation capacity, is subject to multiple factors (including natural gas injections and withdrawals at various delivery points along the pipeline and the utilization of compression) which may reduce the throughput capacity from specified capacity levels.
Dekatherm	Million British thermal units. A therm factor is used by gas companies to convert the volume of gas used to its heat equivalent, and thus calculate the actual energy used.
Mcf	thousand cubic feet
MMBtu	million British thermal unit
MMcf	million cubic feet
Bcf	billion cubic feet
NGL	natural gas liquid, such as propane, butane and natural gasoline
Tcf	trillion cubic feet
LIBOR	London Interbank Offered Rate
NYMEX	New York Mercantile Exchange
Reservoir	A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

Table of Contents

PART I FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	June 30, 2008	December 31, 2007
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 58,546	$ 56,467
Marketable securities	16,831	3,002
Accounts receivable, net of allowance for doubtful accounts	1,047,478	822,027
Accounts receivable from related companies	19,529	24,438
Inventories	179,235	361,954
Exchanges receivable	66,825	37,321
Deposits paid to vendors	60,383	42,273
Prepaid expenses and other current assets	72,462	62,477
Total current assets	1,521,289	1,409,959
PROPERTY, PLANT AND EQUIPMENT, net	7,457,490	6,433,788
ADVANCES TO AND INVESTMENT IN AFFILIATES	1,281	86,167
GOODWILL	746,377	728,109
INTANGIBLES AND OTHER LONG-TERM ASSETS, net	369,276	350,138
Total assets	$ 10,095,713	$ 9,008,161

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED BALANCE SHEETS

(Dollars in thousands)

(unaudited)

	June 30, 2008	December 31, 2007
LIABILITIES AND PARTNERS CAPITAL		
CURRENT LIABILITIES:		
Accounts payable	$ 1,006,824	$ 672,388
Accounts payable to related companies	26,052	48,483
Exchanges payable	68,863	40,382
Customer advances and deposits	83,112	75,831
Accrued and other current liabilities	176,653	180,465
Accrued capital expenditures	173,776	87,622
Interest payable	77,006	63,254
Current maturities of long-term debt	43,712	47,036
Total current liabilities	1,655,998	1,215,461
LONG-TERM DEBT, less current maturities	4,870,077	4,297,264
DEFERRED INCOME TAXES	105,845	102,762
OTHER LONG-TERM LIABILITIES	15,282	13,483
COMMITMENTS AND CONTINGENCIES (Note 12)		
Total liabilities	6,647,202	5,628,970
PARTNERS CAPITAL:		
General Partner	145,780	160,193
Limited Partners:		
Common Unitholders (142,830,540 and 142,069,957 units authorized, issued and outstanding at June 30, 2008 and December 31, 2007, respectively)	3,293,585	3,192,092
Class E Unitholders (8,853,832 units authorized, issued and outstanding held by subsidiary and reported as treasury units)		
	3,439,365	3,352,285
Accumulated other comprehensive income, per accompanying statements	9,146	26,906
Total partners capital	3,448,511	3,379,191
Total liabilities and partners capital	$ 10,095,713	$ 9,008,161

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Dollars in thousands, except per unit data)

(unaudited)

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
REVENUES:				
Natural gas operations	$ 2,375,637	$ 1,406,598	$ 4,383,484	$ 2,899,436
Retail propane	249,449	252,584	847,587	751,836
Other	28,390	55,604	61,776	125,994
Total revenues	2,653,476	1,714,786	5,292,847	3,777,266
COSTS AND EXPENSES:				
Cost of products sold natural gas operations	1,952,569	1,095,040	3,529,837	2,233,749
Cost of products sold retail propane	163,962	158,167	556,517	462,801
Cost of products sold other	7,541	34,180	17,436	76,653
Operating expenses	197,143	148,903	376,113	282,712
Depreciation and amortization	62,421	47,402	121,249	92,762
Selling, general and administrative	44,011	39,786	92,380	78,919
Total costs and expenses	2,427,647	1,523,478	4,693,532	3,227,596
OPERATING INCOME	225,829	191,308	599,315	549,670
OTHER INCOME (EXPENSE):				
Interest expense, net of interest capitalized	(68,416)	(46,149)	(123,965)	(86,921)
Equity in earnings (losses) of affiliates	(169)	839	(95)	325
Gain (loss) on disposal of assets	515	(2,500)	(936)	(5,729)
Other income, net	17,957	17,751	35,594	19,174
INCOME BEFORE INCOME TAX EXPENSE AND MINORITY INTERESTS	175,716	161,249	509,913	476,519
Income tax expense	10,042	3,560	15,904	6,860
INCOME BEFORE MINORITY INTERESTS	165,674	157,689	494,009	469,659
Minority interests		(223)		(1,079)
NET INCOME	165,674	157,466	494,009	468,580
GENERAL PARTNER S INTEREST IN NET INCOME	78,983	59,962	153,347	120,529
LIMITED PARTNERS INTEREST IN NET INCOME	$ 86,691	$ 97,504	$ 340,662	$ 348,051
BASIC NET INCOME PER LIMITED PARTNER UNIT	$ 0.61	$ 0.71	$ 2.13	$ 2.10
BASIC AVERAGE NUMBER OF UNITS OUTSTANDING	142,827,051	136,978,390	142,794,658	136,977,771
DILUTED NET INCOME PER LIMITED PARTNER UNIT	$ 0.60	$ 0.71	$ 2.12	$ 2.09

DILUTED AVERAGE NUMBER OF UNITS OUTSTANDING	143,353,304	137,368,358	143,323,778	137,359,170

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(Dollars in thousands)

(unaudited)

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Net income	$ 165,674	$ 157,466	$ 494,009	$ 468,580
Other comprehensive income (loss), net of tax:				
Reclassification to earnings of gains and losses on derivative instruments accounted for as cash flow hedges	9,482	(18,432)	(13,209)	(139,942)
Change in value of derivative instruments accounted for as cash flow hedges	(1,273)	(1,124)	(7,494)	74,828
Change in value of available-for-sale securities	3,110	(450)	2,943	971
Comprehensive income	$ 176,993	$ 137,460	$ 476,249	$ 404,437
Reconciliation of Accumulated Other Comprehensive Income (Loss), net of tax				
Balance, beginning of period	$ (2,173)	$ 15,466	$ 26,906	$ 59,603
Current period reclassification to earnings	9,482	(18,432)	(13,209)	(139,942)
Current period change in value	1,837	(1,574)	(4,551)	75,799
Balance, end of period	$ 9,146	$ (4,540)	$ 9,146	$ (4,540)
Components of Accumulated Other Comprehensive Income (Loss), net of tax, end of period				
Net gain (loss) on commodity related hedges			$ 5,382	$ (6,632)
Net gain on interest rate hedges			305	1,033
Available-for-sale securities			3,459	1,059
Balance, end of period			$ 9,146	$ (4,540)

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2008

(Dollars in thousands)

(unaudited)

	General Partner	Limited Partner Common Unitholders
Balance, December 31, 2007	$ 160,193	$ 3,192,092
Distributions to partners	(162,666)	(284,757)
Net proceeds from issuance of Limited Partner Units		34,965
General Partner capital contribution	747	
Contribution receivable from General Partner	(5,854)	
Tax effect of remedial income allocation from tax amortization of goodwill		(1,949)
Non-cash executive compensation	13	612
Non-cash unit-based compensation expense		11,960
Net income	153,347	340,662
Balance, June 30, 2008	$ 145,780	$ 3,293,585

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

5

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

(unaudited)

	Six Months Ended	
	June 30, 2008	**May 31, 2007**
NET CASH PROVIDED BY OPERATING ACTIVITIES	$ 779,577	$ 694,821
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash paid for acquisitions, net of cash acquired	(56,786)	(54,648)
Capital expenditures, net of contributions in aid of construction costs	(951,732)	(562,132)
(Advances to) repayments from affiliates, net	63,534	(33,969)
Proceeds from the sale of assets	16,955	13,270
Net cash used in investing activities	(928,029)	(637,479)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowings	3,511,930	1,678,443
Principal payments on debt	(2,928,044)	(1,348,426)
Net proceeds from issuance of Limited Partner Units	34,965	
Distributions to partners	(447,423)	(326,043)
Debt issuance costs	(20,897)	(452)
Net cash provided by financing activities	150,531	3,522
INCREASE IN CASH AND CASH EQUIVALENTS	2,079	60,864
CASH AND CASH EQUIVALENTS, beginning of period	56,467	34,746
CASH AND CASH EQUIVALENTS, end of period	$ 58,546	$ 95,610

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

Table of Contents

ENERGY TRANSFER PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

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

(unaudited)

1. OPERATIONS AND ORGANIZATION:

The accompanying condensed consolidated balance sheet as of December 31, 2007, 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, we or the Partnership) as of June 30, 2008 and for the three-month and six-month periods ended June 30, 2008 and May 31, 2007, 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 (SEC). Accordingly, they do not include all the information and footnotes required by GAAP for complete consolidated financial statements. However, management believes that the disclosures made are adequate to make the information not misleading. The results of operations for interim periods are not necessarily indicative of the results to be expected for a full year due to the seasonal nature of the Partnership s operations, maintenance activities and the impact of forward natural gas prices and differentials on certain derivative financial instruments that are accounted for using mark-to-market accounting.

In the opinion of management, all adjustments (all of which are normal and recurring) have been made that are necessary to fairly state the Partnership s consolidated financial position as of June 30, 2008, and its results of operations and cash flows for the three-month and six-month periods ended June 30, 2008 and May 31, 2007. The unaudited interim condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the fiscal year ended August 31, 2007, as filed with the SEC on October 30, 2007, and the Partnership s Report on Form 8-K as of December 31, 2007 and for the four-month transition period then ended, filed with the SEC on March 19, 2008.

In November 2007, we filed a Form 8-K indicating that our Limited Partnership Agreement had been amended to change our fiscal year end to the calendar year. Thus, our current fiscal year began on January 1, 2008. The Partnership completed a four-month transition period that began September 1, 2007 and ended December 31, 2007 and filed a transition report on Form 10-Q for that period in February 2008. The financial statements contained herein cover the three-month and six-month periods ended June 30, 2008 and the three-month and six-month periods ended May 31, 2007 (the three and six-month periods of the previous fiscal year most nearly comparable to the three and six-month periods ended June 30, 2008).

We did not recast the financial data for the prior fiscal period because the financial reporting processes in place at that time included certain procedures that were completed only on a fiscal quarterly basis. Consequently, to recast those periods would have been impractical and would not have been cost-justified. Furthermore, we believe the information and data of the three and six-month periods ended May 31, 2007 is comparable to what would have been reported for the three and six-month periods ended June 30, 2007 if we had recast the prior period information. Such comparability is impacted primarily by weather, fluctuations in commodity prices, volumes of natural gas sold and transported, our hedging strategies and the use of financial instruments, trading activities, basis differences between market hubs and interest rates. We believe that the trends indicated by comparison of the results for the three and six-month periods ended May 31, 2007 to the periods ended June 30, 2008 are substantially similar to what would have been reflected had we recast the information for the periods ended June 30, 2007.

Certain prior period amounts have been reclassified to conform to the fiscal 2008 presentation. These reclassifications had no impact on net income or total partners capital for the periods presented.

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 consist of four reportable segments, which are primarily conducted through four subsidiary operating partnerships (collectively the Operating Partnerships), as follows:

La Grange Acquisition, L.P., dba Energy Transfer Company (ETC OLP), a Texas limited partnership engaged in midstream and intrastate transportation and storage natural gas operations;

Table of Contents

Energy Transfer Interstate Holdings, LLC (ET Interstate), the parent company of Transwestern Pipeline Company, LLC (Transwestern) and ETC Midcontinent Express Pipeline, LLC (ETC MEP), all of which are Delaware limited liability companies engaged in interstate transportation of natural gas;

Heritage Operating L.P. (HOLP), a Delaware limited partnership primarily engaged in retail propane operations; and

Titan Energy Partners, LP (Titan), a Delaware limited partnership engaged in retail propane operations.

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

ETC OLP owns and operates, through its wholly and majority-owned subsidiaries, natural gas gathering systems, intrastate natural gas pipeline systems and gas processing plants and is engaged in the business of purchasing, gathering, transporting, processing, and marketing natural gas and natural gas liquids (NGLs) in the states of Texas, Louisiana, New Mexico, Utah and Colorado.

Our interstate transportation operations principally focus on natural gas transportation of Transwestern and the joint venture activities of ETC MEP.

Our retail propane segment sells propane and propane-related products and services to residential, commercial, industrial and agricultural customers.

2. SIGNIFICANT ACQUISITIONS:

Four-Month Transition Period Ended December 31, 2007

In October 2007, we acquired the Canyon Gathering System midstream business of Canyon Gas Resources, LLC from Cantera Resources Holdings, LLC (the Canyon acquisition) for $305.2 million in cash, subject to working capital adjustments as defined in the purchase and sale agreement. The Canyon Gathering System has over 400,000 dedicated acres under long-term contracts. The Canyon assets include a gathering system in the Piceance-Uinta Basin which consists of over 1,300 miles of 2-inch to 16-inch pipe with a projected capacity of over 300 MMcf/d, as well as six conditioning plants for NGL extraction and gas treatment with a processing capacity of 90 MMcf/d. Some of the largest U.S. producers are active in the area and are major customers of the system. The results of the Canyon Gathering System are included in our midstream segment since the acquisition date.

The Canyon acquisition was accounted for under the purchase method of accounting in accordance with FASB Statement No. 141, *Business Combinations*, (SFAS 141), and the purchase price was preliminarily allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of the acquisition, as follows:

Accounts receivable	$ 4,303
Inventory	183
Prepaid and other current assets	1,612
Property, plant, and equipment	284,910
Contract rights and customer lists (6 to 15 year life)	6,351
Goodwill	10,959
Total assets acquired	308,318
Accounts payable	(2,299)
Customer advances and deposits	(867)
Total liabilities assumed	(3,166)

Net assets acquired	$ 305,152

The Canyon acquisition was not material for pro forma disclosure purposes.

We expect to finalize the purchase price allocation for the Canyon acquisition in the third quarter of 2008 upon receipt of a final appraisal and other pending information.

Other

In March 2008 we made a purchase price adjustment for a contingent payment associated with a natural gas gathering system in north Texas purchased in September 2006. The purchase and sale agreement had a contingent payment not to exceed $25.0 million which was to be determined eighteen months after the closing date. The contingent payment of $8.7 million was recorded as an adjustment to goodwill in the midstream segment.

3. ESTIMATES, SIGNIFICANT ACCOUNTING POLICIES AND NEW ACCOUNTING STANDARDS:

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the accrual for and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The natural gas industry conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results for the midstream and transportation and storage segments are estimated using volume estimates and market prices. Any differences between estimated results and actual results are recognized in the following month s financial statements. Management believes that the operating results estimated for the three and six months ended June 30, 2008 and May 31, 2007 represent the actual results in all material respects.

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, estimates related to our unit-based compensation plans, deferred taxes, assets and liabilities resulting from the regulated ratemaking process, contingency reserves and environmental reserves. Actual results could differ from those estimates.

Significant Accounting Policies

Financial Assets and Liabilities at Fair Value

We adopted Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, (SFAS 157) effective January 1, 2008. SFAS 157 provides a definition of fair value, establishes a fair value framework and hierarchy under GAAP and provides for expanded disclosures of fair value measurements. SFAS 157 does not require any new fair value measurements other than those established by other GAAP requirements. As noted below, under New Accounting Standards , the effective date of SFAS 157 has been deferred with respect to certain non-financial assets and liabilities.

We have marketable securities, commodity derivatives and interest rate derivatives that are accounted for as assets and liabilities at fair value in our condensed consolidated balance sheets. In accordance with SFAS 157, we determine the fair value of our assets and liabilities subject to fair value measurement by using the highest possible Level as defined in SFAS 157. Level 1 inputs are observable quotes in an active market for identical assets and liabilities. We consider the valuation of marketable securities and commodity derivatives transacted through a clearing broker with a published price from the appropriate exchange as a Level 1 valuation. Level 2 inputs are inputs observable for similar assets and liabilities. We consider over-the-counter commodity derivatives entered into directly with third parties Level 2 valuation since the values of these derivatives are quoted on an exchange for similar transactions. We consider the valuation of our interest rate derivatives as Level 2 since we use a LIBOR curve based on quotes from an active exchange of Eurodollar futures for the same period as the future interest swap settlements and discount the future cash flows accordingly, including the effects of our credit risk. Level 3 utilizes significant unobservable inputs. We currently do not have any fair value measurements within the scope of SFAS 157 that require the use of significant unobservable inputs and therefore do not have any assets or liabilities considered as Level 3 valuations as defined by SFAS 157.

Table of Contents

The following table summarizes the fair value of our financial assets and liabilities as of June 30, 2008 based on inputs used to derive their fair values in accordance with SFAS 157:

Description	Fair Market Value Total	Fair Value Measurements at Reporting Date Using: Quoted prices in Active Markets for Identical Assets and Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)
Assets			
Marketable Securities	$ 16,831	$ 16,831	$
Commodity Derivatives	10,553	2,611	7,942
Liabilities			
Commodity Derivatives	(21,493)	(13,845)	(7,648)
Interest Rate Derivatives	(2,086)		(2,086)
	$ 3,805	$ 5,597	$ (1,792)

Contributions in Aid of Construction Costs

On certain of our capital projects, third parties are obligated to reimburse us for all or a portion of project expenditures. The majority of such arrangements are associated pipeline construction and production well tie-ins. Contributions in aid of construction costs (CIAC) are netted against our project costs as they are received, and the excess of any CIAC which exceeds our total projects costs is recognized as other income in the period in which it was realized. During the three and six months ended June 30, 2008 $2.6 million and $42.6 million, respectively, of CIAC was received and netted against our project costs. During the three and six months ended May 31, 2007, $1.4 million and $4.0 million of CIAC was received and netted against our project costs, respectively. In March 2008, we received a reimbursement of $40.0 million related to an extension on our Southeast Bossier pipeline resulting in an excess over total project costs of $7.1 million which is recorded in other income on our condensed consolidated statement of operations for the six months ended June 30, 2008. The total CIAC recorded to other income was not significant for the three-month periods ended June 30, 2008 and May 31, 2007. For the six months ended June 30, 2008 and May 31, 2007, the total CIAC recorded to other income was $7.9 million and $0.2 million, respectively.

New Accounting Standards

FASB Statement No. 141 (Revised 2007), *Business Combinations* (SFAS 141R). On December 4, 2007, the FASB issued SFAS 141R. SFAS 141R will significantly change the accounting for business combinations. Under SFAS 141R, an acquiring entity will be required to recognize all the assets acquired and liabilities assumed in a transaction at the acquisition-date fair value with limited exceptions. Statement 141R will change the accounting treatment for certain specific items, including:

Acquisition costs will generally be expensed as incurred;

Non-controlling interests (currently referred to as minority interests) will be valued at fair value at the acquisition date;

Acquired contingent liabilities will be recorded at fair value at the acquisition date and subsequently measured at either the higher of such amount or the amount determined under existing guidance for non-acquired contingencies;

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

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

Changes in deferred tax asset valuation allowances and income tax uncertainties after the acquisition date generally will affect income tax expense.

Table of Contents

SFAS 141R also includes a substantial number of new disclosure requirements. SFAS 141R is to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. Earlier adoption is prohibited. Accordingly, we are required to record and disclose business combinations following existing GAAP until January 1, 2009.

FASB Statement No. 161, *Disclosures about Derivative Instruments and Hedging Activities An Amendment of FASB Statement No. 133* (SFAS 161). Issued in March, 2008, SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities with the intent to provide users of financial statements with an enhanced understanding of (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (SFAS 133) and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 requires qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments, and disclosures about credit-risk-related contingent features in derivative agreements. This statement has the same scope as SFAS 133, and accordingly applies to all entities. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. This Statement encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 only affects disclosure requirements; therefore, our adoption of this statement effective January 1, 2009 will not impact our financial position or results of operations.

FASB Statement No. 162, *The Hierarchy of Generally Accepted Accounting Principles* (SFAS 162). In May 2008, the FASB issued SFAS 162, which establishes a consistent framework, or hierarchy, for selecting the accounting principles used to prepare financial statements of nongovernmental entities in conformity with GAAP. SFAS 162 is effective 60 days following the SEC s approval of the Public Company Accounting Oversight Board (PCAOB) amendments to its Interim Auditing Standards. We do not expect SFAS 162 to have a material impact on the preparation of our consolidated financial statements.

EITF Issue No. 07-4, *Application of the Two Class Method Under FASB Statement No. 128, Earnings Per Share, to Master Limited Partnerships (MLP)* (EITF 07-4). The FASB ratified the final consensus on EITF 07-4 on March 26, 2008. The key elements of the final consensus relate to: (a) the scope of the issue; (b) when Incentive Distribution Rights (IDRs) are considered participating securities under the two-class method for Earnings Per Share (EPS); (c) the calculation provisions; and (d) the transition and effective date. EITF 07-4 addresses how current period earnings of an MLP should be allocated to the general partner, limited partners, and, when applicable, the holder of IDRs when applying the two-class method under Statement 128. EITF 07-4 applies to MLPs that are required to make incentive distributions when certain thresholds have been met regardless of whether the IDR is a separate limited partner interest or embedded in the general partner interest. EITF 07-4 only addresses incentive distributions that are treated as equity distributions and does not address whether the incentive distributions are compensation or equity distributions. Specifically, if IDRs are separate from the general partner interest, then they are considered separate participating securities for purposes of applying the two-class method of determining EPS. Under this situation, the two-class method is used to determine EPS for the general partner interest, limited partner interest and the IDR holders interest. EITF 07-4 provides that when earnings for the period exceed distributions, the excess undistributed earnings are to be allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of income. When distributions for the period exceed earnings, the income is first allocated equal to the actual distributions. The resulting deficit is allocated to the general partner, limited partners and holders of the IDRs based on the terms of the partnership agreement related to the allocation of losses. EITF 07-4 is effective with the first fiscal year beginning after December 15, 2008, including interim periods within those fiscal years, and requires retrospective application of the guidance to all periods presented. Early application is prohibited. Accordingly, we are required to record and disclose EPS information following existing GAAP until January 1, 2009. We are currently evaluating the impact of the adopting of EITF 07-4. While the actual impact of EITF 07-4 will depend on each specific period s earnings and distributions, the principles established in such EITF differ significantly from the present method used to compute earnings per unit when earnings exceed distributions. Depending on the actual earnings achieved, the impact of EITF 07-4 on the computation of our earnings per limited partner unit may be significant.

FASB Staff Position No. EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities* (FSP EITF 03-6-1). FSP EITF 03-6-1 was issued by the FASB on June 16, 2008. FSP EITF 03-6-1 clarifies that unvested share-based payment awards constitute participating securities, if such awards include nonforfeitable rights to dividends or dividend equivalents. Consequently,

Table of Contents

awards that are deemed to be participating securities must be allocated earnings in the computation of earnings per share under the two-class method. FSP EITF 03-6-1 is effective for fiscal years beginning after December 15, 2008. We intend to adopt FSP EITF 03-6-1 effective January 1, 2009 and are currently evaluating the impact of adoption on our consolidated financial statements.

FASB Staff Position (FSP) SFAS 157-2, *Effective Date of FASB Statement No. 157 (FSP 157-2)*. FSP 157-2 defers the effective date of SFAS 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years, for all nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As allowed under FSP 157-2, we have not applied the provisions of SFAS 157 to our nonfinancial assets and liabilities measured at fair value, which include impaired nonfinancial assets and certain assets and liabilities acquired in business combinations. We are currently evaluating the impact of our adoption of FSP 157-2 effective January 1, 2009 on our consolidated financial statements.

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 provided by operating activities is comprised of the following:

	Six Months Ended	
	June 30, 2008	May 31, 2007
Net income	$ 494,009	$ 468,580
Reconciliation of net income to net cash provided by operating activities:		
Depreciation and amortization	121,249	92,762
Amortization of finance costs charged to interest	2,575	1,946
Provision for loss on accounts receivable	2,802	1,361
Non-cash unit-based compensation expense	11,960	8,231
Non-cash executive compensation	625	
Deferred income taxes	891	(2,917)
Loss on disposal of assets	936	5,729
Distributed earnings (losses) of affiliates, net	3,309	(325)
Minority interests and other		1,189
Changes in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	(232,767)	(6,979)
Accounts receivable from related companies	108	(2,065)
Inventories	185,710	202,793
Deposits paid to vendors	(18,110)	32,648
Exchanges receivable	(29,503)	(6,236)
Prepaid expenses and other	(10,289)	15,084
Intangibles and other long-term assets	(2,660)	(5,408)
Regulatory assets	(8,607)	933
Accounts payable	309,764	46,623
Accounts payable to related companies	(22,453)	12,958
Customer advances and deposits	7,253	(62,173)
Exchanges payable	28,481	9,077
Accrued and other current liabilities	(57,983)	(16,089)
Other long-term liabilities	2,277	(467)
Income taxes payable	5,154	(2,229)
Price risk management liabilities, net	(15,154)	(100,205)

Net cash provided by operating activities	$ 779,577	$ 694,821

12

Table of Contents

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

	Six Months Ended	
	June 30, 2008	May 31, 2007
NON-CASH INVESTING ACTIVITIES:		
Transfer of investment in affiliate in purchase of Transwestern	$	$ 956,348
Investment in Calpine Corporation acquired in exchange for accounts receivable	$ 14,879	$
NON-CASH FINANCING ACTIVITIES:		
Long-term debt assumed and non-compete agreement notes payable issued in acquisitions	$ 3,948	$ 533,255
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:		
Cash paid during the period for interest, net of $16,470 and $12,049 capitalized for June 30, 2008 and May 31, 2007, respectively	$ 123,772	$ 96,008
Cash paid during the period for income taxes	$ 8,707	$ 3,464

5. ACCOUNTS RECEIVABLE:

We exchanged a portion of our outstanding accounts receivable from Calpine Energy Services, L.P. for Calpine Corporation (Calpine) common stock during the first quarter of 2008 pursuant to a settlement reached with Calpine related to their bankruptcy reorganization. The stock was included as marketable securities which are classified as available-for-sale securities and are reflected as a current asset on the condensed consolidated balance sheet as of June 30, 2008 at a fair value of $14.9 million.

Table of Contents

Accounts receivable consisted of the following:

	June 30, 2008	December 31, 2007
Midstream and intrastate transportation and storage	$ 904,043	$ 612,533
Interstate transportation	24,993	31,676
Propane	124,717	183,516
Less allowance for doubtful accounts	(6,275)	(5,698)
Total, net	$ 1,047,478	$ 822,027

The activity in the allowance for doubtful accounts for the propane operations for the six months ended June 30, 2008 consisted of the following:

Balance, December 31, 2007	$ 5,698
Accounts receivable written off, net of recoveries	(2,225)
Provision for loss on accounts receivable	2,802
Balance, June 30, 2008	$ 6,275

6. INVENTORIES:

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

Inventories consisted of the following:

	June 30, 2008	December 31, 2007
Natural gas, propane and other NGLs	$ 158,591	$ 342,457
Appliances, parts and fittings and other	20,644	19,497
Total inventories	$ 179,235	$ 361,954

Table of Contents

7. INTANGIBLES AND OTHER LONG-TERM 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:

	June 30, 2008		December 31, 2007	
	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
Amortizable intangible assets:				
Noncompete agreements (5 to 15 years)	$ 39,173	$ (21,878)	$ 34,855	$ (19,438)
Customer lists (3 to 15 years)	143,420	(33,228)	139,097	(26,821)
Contract rights (6 to 15 years)	23,015	(2,796)	23,015	(1,849)
Other (10 years)	2,677	(1,853)	2,677	(1,463)
Total amortizable intangible assets	208,285	(59,755)	199,644	(49,571)
Non-amortizable assets Trademarks	72,148		70,339	
Total intangible assets	280,433	(59,755)	269,983	(49,571)
Other long-term assets:				
Financing costs (3 to 15 years)	55,161	(13,430)	42,432	(10,578)
Regulatory assets	83,621	(4,244)	73,687	(2,623)
Other	27,490		26,808	
Total intangibles and other long-term assets	$ 446,705	$ (77,429)	$ 412,910	$ (62,772)

Aggregate amortization expense of intangible assets is as follows:

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Reported in depreciation and amortization	$ 4,321	$ 4,307	$ 8,620	$ 8,389
Reported in interest expense	$ 1,570	$ 1,232	$ 2,852	$ 2,493

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

Years Ending December 31:	
2008 (remainder)	$ 13,066
2009	25,451
2010	23,546
2011	22,086
2012	20,020

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 June 30, 2008 or May 31, 2007.

8. <u>INCOME TAXES</u>:

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

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

Table of Contents

year basis under the applicable income tax provisions. If the amount of our non-qualifying income exceeds this statutory limit, we would be taxed as a corporation. Accordingly, certain activities that generate non-qualifying income are conducted through taxable corporate subsidiaries (C corporations). These C corporations are subject to federal and state income tax and pay the income taxes related to the results of their operations. For the three and six-month periods ended June 30, 2008 and May 31, 2007, 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 basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the underlying assets are received and liabilities settled.

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

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Current provision:				
Federal	$ 5,369	$ 492	$ 4,846	$ 3,828
State	5,350	3,462	8,622	5,948
Total	10,719	3,954	13,468	9,776
Deferred provision (benefit):				
Federal	(223)	(394)	2,611	(2,641)
State	(454)		(175)	(275)
Total	(677)	(394)	2,436	(2,916)
Total tax provision	$ 10,042	$ 3,560	$ 15,904	$ 6,860
Effective tax rate	5.71%	2.20%	3.12%	1.44%

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

9. INCOME PER LIMITED PARTNER UNIT:

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

16

Table of Contents

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

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Net income	$ 165,674	$ 157,466	$ 494,009	$ 468,580
Adjustments:				
General Partner s equity ownership	(3,313)	(3,149)	(9,880)	(9,371)
General Partner s incentive distributions	(75,670)	(56,813)	(143,467)	(111,158)
Limited Partners interest in net income	86,691	97,504	340,662	348,051
Additional earnings allocation to General Partner			(36,595)	(60,488)
Net income available to limited partners	$ 86,691	$ 97,504	$ 304,067	$ 287,563
Weighted average limited partner units basic	142,827,051	136,978,390	142,794,658	136,977,771
Basic net income per limited partner unit	$ 0.61	$ 0.71	$ 2.13	$ 2.10
Weighted average limited partner units	142,827,051	136,978,390	142,794,658	136,977,771
Dilutive effect of Unit Grants	526,253	389,968	529,120	381,399
Weighted average limited partner units, assuming dilutive effect of Unit Grants	143,353,304	137,368,358	143,323,778	137,359,170
Diluted net income per limited partner unit	$ 0.60	$ 0.71	$ 2.12	$ 2.09

10. DEBT OBLIGATIONS:

Our debt obligations consisted of the following:

	June 30, 2008	December 31, 2007	Maturities
ETP Senior Notes:			
2008 6.0% Senior Notes, net of discount of $635	$ 349,365	$	One payment of $350,000 due July 13, 2013. Interest is paid semi-annually.
2008 6.7% Senior Notes, net of discount of $1,734	598,266		One payment of $600,000 due July 2, 2018. Interest is paid semi-annually.
2008 7.5% Senior Notes, net of discount of $5,729	544,271		One payment of $550,000 due July 1, 2038. Interest is paid semi-annually.
2006 6.125% Senior Notes, net of discount of $309 and $322, respectively	399,691	399,678	One payment of $400,000 due February 15, 2017. Interest is paid semi-annually.
2006 6.625% Senior Notes, net of discount of $2,218 and $2,231, respectively	397,782	397,769	One payment of $400,000 due October 15, 2036. Interest is paid semi-annually.
2005 5.95% Senior Notes, net of discount of $1,633 and $1,733, respectively	748,367	748,267	One payment of $750,000 due February 1, 2015. Interest is paid semi-annually.

2005 5.65% Senior Notes, net of discount of $260 and $288, respectively	399,740	399,712	One payment of $400,000 due August 1, 2012. Interest is paid semi-annually.

Table of Contents

Transwestern Senior Unsecured Notes:			
5.39% Senior Unsecured Series Notes, including premium of $3,788 and $4,077, respectively	91,788	92,077	One payment of $88,000 due November 17, 2014. Interest is paid semi-annually.
5.54% Senior Unsecured Series Notes, net of discount of $4,593 and $4,855, respectively	120,407	120,145	One payment of $125,000 due November 17, 2016. Interest is paid semi-annually.
5.64% Senior Unsecured Series Notes	82,000	82,000	One payment due May 24, 2017. Interest is paid semi-annually.
5.89% Senior Unsecured Series Notes	150,000	150,000	One payment due May 24, 2022. Interest is paid semi-annually.
6.16% Senior Unsecured Series Notes	75,000	75,000	One payment due May 24, 2037. Interest is paid semi-annually.
HOLP Senior Secured Notes:			
1996 8.55% Senior Secured Notes	36,000	48,000	Annual payments of $12,000 due each June 30 through 2011. Interest is paid semi-annually.
1997 Medium Term Note Program:			
7.17% Series A Senior Secured Notes	4,800	4,800	Annual payments of $2,400 due each November 19 through 2009. Interest is paid semi-annually.
7.26% Series B Senior Secured Notes	10,000	10,000	Annual payments of $2,000 due each November 19 through 2012. Interest is paid semi-annually.
2000 and 2001 Senior Secured Promissory Notes:			
8.55% Series B Senior Secured Notes	13,714	13,714	Annual payments of $4,571 due each August 15 through 2010. Interest is paid quarterly.
8.59% Series C Senior Secured Notes	15,500	15,500	Annual payments of $4,000 due August 15, 2008, and $5,750 due each August 15, 2009 and 2010. Interest is paid quarterly.
8.67% Series D Senior Secured Notes	58,000	58,000	Annual payments of $12,450 due August 15, 2008 and 2009, $7,700 due August 15, 2010, $12,450 due August 15, 2011, and $12,950 due August 15, 2012. Interest is paid quarterly.
8.75% Series E Senior Secured Notes	7,000	7,000	Annual payments of $1,000 due each August 15, 2009 through 2015. Interest is paid quarterly.
8.87% Series F Senior Secured Notes	40,000	40,000	Annual payments of $3,636 due each August 15, 2010 through 2020. Interest is paid quarterly.
7.21% Series G Senior Secured Notes		3,800	Paid and retired in May 2008.
7.89% Series H Senior Secured Notes	5,818	6,545	Annual payments of $727 due each May 15 through 2016. Interest is paid quarterly.
7.99% Series I Senior Secured Notes	16,000	16,000	One payment of $16,000 due May 15, 2013. Interest is paid quarterly.
Revolving Credit Facilities:			
ETP Revolving Credit Facility (including Swingline loan option)	734,177	1,626,948	Available through June 2012 see terms below under ETP Credit Facility .
HOLP Fourth Amended and Restated Senior Revolving Credit Facility		15,000	Available through June 30, 2011 - see terms below under HOLP Credit Facility .

Table of Contents

Other Long-Term Debt:			
Notes payable on noncompete agreements with interest imputed at rates averaging 8.37% and 5.51 % for June 30, 2008 and December 31, 2007, respectively	13,092	11,171	Due in installments through 2014.
Other	3,011	3,174	Due in installments through 2024.
	4,913,789	4,344,300	
Current maturities	(43,712)	(47,036)	
	$ 4,870,077	$ 4,297,264	

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

2008 (remainder)	$ 28,508
2009	45,330
2010	40,519
2011	34,189
2012	1,156,790
Thereafter	3,608,453
	$ 4,913,789

ETP 2008 Senior Notes

On March 28, 2008, we issued a total of $1.5 billion aggregate principal amount of Senior Notes comprised of $350.0 million of 6.00% Senior Notes due 2013, $600.0 million of 6.70% Senior Notes due 2018, and $550.0 million of 7.50% Senior Notes due 2038 (collectively, the ETP 2008 Senior Notes). We used the proceeds of approximately $1.48 billion (net of bond discounts of $8.2 million and other offering costs of $10.8 million) from the issuance of the ETP 2008 Senior Notes to repay borrowings and accrued interest outstanding under our $500.0 million, 364-day term loan credit facility (the 364-Day Credit Facility) and to repay a portion of amounts outstanding under the ETP Credit Facility. The Partnership may redeem some or all of the ETP 2008 Senior Notes at any time, or from time to time, pursuant to the terms of the indenture. The ETP 2008 Senior Notes were registered under the Securities Act of 1933 (as amended) pursuant to our Registration Statement on Form S-3ASR, as supplemented by the Prospectus Supplement dated March 25, 2008, filed with the SEC on March 26, 2008. The 364-Day Credit Facility was a single draw term loan for general corporate purposes, with an applicable Eurodollar rate plus 1.000% per annum based on the current rating by the rating agencies or at the Base Rate for a designated period. The indebtedness under the 364-Day Credit Facility was unsecured and not guaranteed by us or any of our subsidiaries.

The ETP 2008 Senior Notes were issued under an indenture containing covenants, which, among other things, restrict our ability to, subject to certain exceptions, incur debt secured by liens, engage in sale and leaseback transactions or merge or consolidate with another entity or sell substantially all of our assets. The ETP 2008 Senior Notes are unsecured obligations of the Partnership and the obligation of the Partnership to repay the ETP Senior Notes is not guaranteed by any of the Partnership s subsidiaries. As a result, the ETP 2008 Senior Notes effectively rank junior to any future indebtedness of ours or our subsidiaries that is both secured and unsubordinated to the extent of the value of the assets securing such indebtedness, and the ETP 2008 Senior Notes effectively rank junior to all indebtedness and other liabilities of our existing and future subsidiaries.

ETP Credit Facility

We have available a $2.0 billion revolving credit facility (the ETP Credit Facility) that is expandable to $3.0 billion at our option (subject to the approval of the administrative agent under the Amended and Restated Credit Agreement, which approval is not to be unreasonably withheld) which matures on July 20, 2012, unless we elect the option of one-year extensions (subject to the approval of each such extension by the lenders holding a majority of the aggregate lending commitments under the ETP Credit Facility). Amounts borrowed under the ETP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The ETP Credit Facility has a swingline loan option of which borrowings and aggregate principal amounts shall not exceed the lesser of (i) the aggregate commitments ($2.0 billion unless expanded to $3.0 billion) less the sum of all outstanding revolving credit loans and the letter of credit obligation and (ii) the swingline commitment.

Table of Contents

As of June 30, 2008, there was a balance of $734.2 million in revolving credit loans (including $87.2 million in swingline loans) and $62.5 million in letters of credit. The weighted average interest rate on the total amount outstanding at June 30, 2008, was 3.078%. The total amount available under the ETP Credit Facility, as of June 30, 2008, which is reduced by any amounts outstanding under the swingline loan and letters of credit, was $1.2 billion. The indebtedness under the ETP Credit Facility is unsecured and not guaranteed by any of the Partnership s subsidiaries and has equal rights to holders of our other current and future unsecured debt.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the HOLP Credit Facility) is available to HOLP through June 30, 2011 which may be expanded to $150.0 million. The HOLP Credit Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Credit Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. As of June 30, 2008, 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 Credit Facility. There were outstanding letters of credit of $1.0 million at June 30, 2008. The sum of the loans made under the HOLP Credit 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 Credit Facility. The amount available at June 30, 2008 was $74.0 million.

11. PARTNERS CAPITAL AND UNIT-BASED COMPENSATION PLANS:
Limited Partner Units

Limited Partner interests are represented by Common and Class E Units that entitle the holders thereof to the rights and privileges specified in the Partnership Agreement, as amended. As of June 30, 2008, we had 142,830,540 Common Units issued and outstanding representing an aggregate 98% Limited Partner interest in us. There are also 8,853,832 Class E Units outstanding that are reported as treasury units, which units are entitled to receive distributions in accordance with their terms.

No person is entitled to preemptive rights in respect of issuances of equity securities by us, except that the General Partner, Energy Transfer Partners GP, L.P. (ETP GP), has the right, in connection with the issuance of any equity security by us, to purchase equity securities on the same terms as these equity securities are issued to third parties sufficient to enable ETP GP and its affiliates to maintain the aggregate percentage equity interest in us as ETP GP and its affiliates owned immediately prior to such issuance. In addition to this right, ETP GP, as our General Partner, has an obligation to contribute additional capital in connection with any such issuance of equity securities by us in order to maintain its 2% general partner interest. These contributions are generally paid by offsetting the required contributions against the funds ETP GP receives from ETP distributions on the general partner and limited partner interests owned by ETP GP.

As of June 30, 2008, approximately $6.0 million of required contributions from ETP GP was outstanding and recorded as a reduction of partners capital. We expect payment for this amount to be received during the three months ending September 30, 2008.

Incentive Distribution Rights represent the contractual right to receive an increasing percentage of quarterly distributions of Available Cash from operating surplus after the minimum quarterly distribution has been paid. ETP GP owns all of the Incentive Distribution Rights.

Common Units

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

Table of Contents

The change in Common Units during the six-month period ended June 30, 2008 is as follows:

	Number of Units
Balance, beginning of period	142,069,957
Common Units issued in connection with a public offering	750,000
Common Units issued under the 2004 Unit Plan	10,583
Balance, end of period	142,830,540

On January 8, 2008, we issued 750,000 Common Units at $48.81 per Common Unit to the underwriters pursuant to the exercise of a 30-day option to purchase Common Units to cover Over-Allotments in connection with a public offering of 5,000,000 ETP Common Units, representing limited partner interests, in December 2007. The proceeds of $35.0 million, net of offerings costs, were used to repay borrowings from the ETP Credit Facility.

On July 21, 2008, we issued 7,750,000 Common Units representing limited partner interests at $39.45 per Common Unit in connection with a public offering. We also granted the underwriters a 30-day option to purchase up to an aggregate of 1,162,500 additional Common Units (Over-Allotment), which was immediately exercised with the equity issuance. Net proceeds of approximately $338.0 million from the offering and Over-Allotment were used to repay a portion of the amount outstanding under the ETP Revolving Credit Facility. We expect to receive $7.2 million related to the capital contribution from our general partner to maintain its 2% general partner s interest in August of 2008.

Quarterly Distributions of Available Cash

On February 14, 2008, we paid a one-time distribution related to the four-month transition period ended December 31, 2007 of $1.125 per Common Unit ($3.375 per unit annualized) to Unitholders of record as of the close of business on February 1, 2008 (an increase of $0.075 per unit on an annualized basis). Our General Partner s Incentive Distribution 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).

On February 18, 2008, we paid a one-time distribution related to the four-month transition period ended December 31, 2007 of $90.9 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its Incentive Distribution Rights.

On May 15, 2008, we paid a per unit cash distribution for the three months ended March 31, 2008 of $0.86875 ($3.475 per Limited Partner Unit annualized) to Unitholders of record as of the close of business on May 5, 2008 (a $0.10 increase from the previous distribution per Limited Partner Unit). We paid $71.8 million in the aggregate for ETP GP s 2% general partner interest in the Partnership and its Incentive Distribution Rights for the three months ended March 31, 2008.

On July 24, 2008, we declared a per unit cash distribution of $0.89375 ($3.575 per Limited Partner Unit annualized) for the three months ended June 30, 2008, which will be paid on August 14, 2008 to Unitholders of record as of the close of business on August 7, 2008. The declaration represents an increase of $0.10 per Limited Partner Unit on an annualized basis from the previous distribution.

The total amount of distributions declared (all from Available Cash from Operating Surplus) related to the six months ended June 30, 2008 was as follows:

Limited Partners -	
Common Units	$ 259,704
Class E Units	6,242
General Partner -	
2% Ownership	8,355
Incentive Distribution Rights	143,467

	$ 417,768

Table of Contents

Unit-Based Compensation Plans

We follow the provisions of Statement of Financial Accounting Standards No. 123 (revised 2004) *Share-Based Payment* (SFAS 123R) for our unit-based compensation plans. Generally, the recipients of the ETP unit grants are not entitled to receive any unit distributions during the required service period for vesting. Accordingly, 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. 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 unit-based compensation expense of $3.9 million and $5.3 million for the three months ended June 30, 2008 and May 31, 2007, respectively. For the six months ended June 30, 2008 and May 31, 2007 we recognized unit-based compensation expense of $12.0 million and $8.2 million, respectively, as discussed below.

2004 Unit Plan

Our Amended and Restated 2004 Unit Plan (the 2004 Unit Plan) provides for awards of up to 1,800,000 ETP Common Units and other rights to our employees, officers, and directors. Any awards that are forfeited or which expire for any reason or any units which are not used in the settlement of an award will be available for grant under the 2004 Unit Plan. Units to be delivered upon the vesting of awards granted under the 2004 Unit Plan may be (i) units acquired by us in the open market, (ii) units already owned by us or our General Partner, or (iii) units acquired by us or our General Partner directly from us, or any other person. We may issue units under the 2004 Unit Plan without registration under the federal securities law, in which case holders of these units would be subject to restrictions on their ability to sell these units, or we may issue units pursuant to a registration statement on Form S-8 filed in September 2007, in which case the holders of these units would not be subject to these restrictions. As of June 30, 2008, 458,115 ETP Common Units were available for future grants under the 2004 Unit Plan.

The 2004 Unit Plan is administered by the Compensation Committee of the Board of Directors of our General Partner (the Compensation Committee) and may be amended from time to time by the Board; provided however, that no amendment will be made without the approval of a majority of the Unitholders (i) if so required under the rules and regulations of the New York Stock Exchange or the Securities and Exchange Commission; (ii) that would extend the maximum period during which an award may be granted under the Plan; (iii) materially increase the cost of the Plan to the Partnership; or (iv) result in this Plan no longer satisfying the requirements of Rule 16b-3 of Section 16 of the Securities and Exchange Act of 1934. This Plan shall terminate no later than the 10th anniversary of its original effective date (June 23, 2014).

Employee Grants

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

Prior to December 2007, substantially all of the awards granted to employees under the 2004 Unit Plan required the achievement of performance objectives in order for the awards to become vested. The expected life of each unit award subject to the achievement of performance objectives is assumed to be the minimum vesting period under the performance objectives of such unit award. Generally, each award was structured to provide that, if the performance objectives related to such award are achieved, one-third of the units subject to such award will vest each year over a three year period. The performance criteria was generally based upon the total return (unit price appreciation plus cash distributions) to our Unitholders as compared to a group of publicly traded partnership peer companies. Compensation expense is recorded based upon the total awards granted over the required service period that are expected to vest based on the estimated level of achievement of performance objectives. As circumstances change, cumulative adjustments of previously-recognized compensation expense are recorded.

Since December 2007, we have also granted unit awards to employees that vest 20% per year over a five year period, with vesting based on continued employment as of each applicable vesting date without regard to the satisfaction of any performance objectives.

Table of Contents

We assumed a weighted average risk-free interest rate of 3.64% for the three and six months ended June 30, 2008 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 granted during the period ended June 30, 2008, the grant-date average per unit cash distributions were estimated to be $9.35. Upon vesting, ETP Common Units are issued.

The following table shows the activity of the employee grants during the six months ended June 30, 2008:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2007	1,039,529	$ 42.27
Awards granted	47,000	39.92
Awards vested	(10,583)	49.20
Awards forfeited	(71,844)	41.54
Unvested awards as of June 30, 2008	1,004,102	$ 42.14

The total expected compensation expense to be recognized related to the unvested employee awards as of June 30, 2008 was:

Years Ending December 31:	
2008 (remainder)	$ 9,501
2009	7,473
2010	3,703
2011	2,025
2012	851

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 Energy Transfer Partners, L.L.C. (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). Commencing on September 1, 2004 and each September 1 thereafter 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 thousand, divided by the fair market value of a Common Unit on such date rounded to the nearest increment of ten Units (Annual Director s Grant). Each grant of an award to a Director Participant will vest at the rate of one third per year, beginning on the first anniversary date of the Award; provided however, notwithstanding the foregoing, (i) all awards to a Director Participant shall become fully vested upon a change in control, as defined by the 2004 Unit 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 4.46% for the three and six months ended June 30, 2008 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 director awards granted during the period ended June 30, 2008, the grant-date average per unit cash distributions were estimated to be $6.17.

Table of Contents

Unvested Director Grant awards as of December 31, 2007 and June 30, 2008 were as follows:

	Number of Units	Weighted Average Fair Value Per Unit
Unvested awards as of December 31, 2007	6,928	$ 40.47
Awards granted	480	45.87
Unvested awards as of June 30, 2008	7,408	$ 40.82

The total expected compensation expense to be recognized related to the unvested Director Awards as of June 30, 2008 was:

Years Ending December 31:	
2008 (remainder)	$ 47
2009	41
2010	10

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. These guidelines include (i) options to purchase a specified number of units at a specified exercise price, which are clearly designated in the award as either an incentive stock option within the meaning of Section 422 of the Internal Revenue Code, or a non-qualifying stock option that is not intended to qualify as an incentive stock option under Section 422; (ii) Unit Appreciation Rights that specify the terms of the fair market value of the award on the date the unit appreciation right is exercised and the strike price; (iii) units; or (iv) any combination hereof. As of June 30, 2008, there have been no Long-Term Incentive Grants made under the Plan.

Related Party Awards

During 2007, a partnership (McReynolds Equity Partners, L.P.), the general partner of which is owned and controlled by the President of our General Partner, awarded to certain new officers of ETP certain rights related to units of Energy Transfer Equity, L.P. (ETE) previously issued by ETE to such officer. These rights include the economic benefits of ownership of these units based on a 5-year vesting schedule whereby the officer 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 market value of the ETE units awarded the ETP employees assuming no forfeitures. Rights related to 55,000 of the ETE units vested in December 2007 and 60,000 unit awards vested in March 2008. In June 2008, 240,000 unit awards were forfeited due to the resignation of an officer of ETP. For the three months ended June 30, 2008, we recognized non-cash compensation expense of $1.0 million related to these awards and reversed $2.7 million of previously-recognized compensation cost related to the forfeiture of these unit awards, for a net benefit of $1.7 million related to these awards. For the three-month period ended May 31, 2007, we recognized non-cash compensation expense of $2.3 million as a result of these awards. For the six-month periods ended June 30, 2008 and May 31, 2007, we recognized non-cash compensation expense of $0.5 million and $2.6 million, respectively, as a result of these awards. As these units were outstanding prior to these awards, the awards do not represent an increase in the number of outstanding units of either ETP or ETE and are not dilutive to cash distributions per unit with respect to either ETP or ETE. As of June 30, 2008, we expect to recognize non-cash compensation expense as follows in future periods related to these awards:

Years Ending December 31:	
2008 (remainder)	$ 1,708
2009	2,310
2010	1,342
2011	640
2012	105

Table of Contents

On July 22, 2008, rights to 240,000 ETE units were awarded to ETP s current chief financial officer. This award has similar terms to those discussed above, including vesting over five years at 20% per year. None of the costs related to this award will be paid by ETP or ETE. Non-cash compensation expense of approximately $7.0 million will be recognized ratably over the 5-year vesting period, beginning in July of 2008.

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

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. In April 2007, the Federal Energy Regulatory Commission (FERC) approved a Stipulation and Agreement of Settlement (Stipulation and Agreement) that resolved the primary components of the rate case. Transwestern s tariff rates and fuel charges are now final for the period of the settlement. Transwestern is not required to file a new rate case until October 1, 2011.

The Phoenix project, as filed with the FERC on September 15, 2006, includes the construction and operation of approximately 260 miles of 36-inch or larger diameter pipeline extending from Transwestern s existing mainline in Yavapai County, Arizona to delivery points in the Phoenix, Arizona area and certain looping on Transwestern s existing San Juan Lateral with approximately 25 miles of 36-inch diameter pipeline. On November 15, 2007, the FERC issued an order granting Transwestern its Certificate of Public Convenience and Necessity (Order). Pursuant to the Order, Transwestern filed its initial Implementation Plan on November 14, 2007 and accepted the Order on November 19, 2007. On December 17, 2007, two parties filed requests for rehearing of the Order and on December 20, 2007, one party filed a motion to stay the Order. On February 21, 2008, the FERC reaffirmed its decision in the Order; thus, Transwestern notified customers of the commencement of construction in January 2008. The San Juan Lateral portion of the project was placed in service effective July 2008 and the pipeline to the Phoenix area is expected to be in service in phases during the third and fourth quarters of 2008. The total project cost estimate, including funds used during construction, is now expected to be 10% to 20% higher than the initial estimate of $710.0 million. The expected increase is due to a variety of factors, including higher than expected costs of obtaining right-of-ways and permits, construction costs and environmental inspector costs. A principal factor in the increased cost of right-of ways and construction costs was the adverse ruling Transwestern received from the Arizona Federal District Court with respect to our request for preliminary injunctive relief for immediate possession of then outstanding rights-of-way. Although Transwestern has appealed this ruling to the Ninth Circuit Court of Appeals, Transwestern has also finalized the acquisition of substantially all of the remaining right-of-way.

On December 13, 2006, we entered into an agreement with Kinder Morgan Energy Partners, L.P. (KMP) for a 50/50 joint development of Midcontinent Express Pipeline, an approximately 500-mile interstate natural gas pipeline that will originate near Bennington, Oklahoma, be routed through Perryville, Louisiana, and terminate at an interconnect with Transco s interstate natural gas pipeline in Butler, Alabama, is currently pending necessary regulatory approvals. On February 14, 2007, Midcontinent Express Pipeline LLC (MEP), the entity formed to own and operate this pipeline, initiated public review of the project pursuant to the FERC s NEPA pre-filing review process. MEP filed its application with the FERC for a Certificate of Public Convenience and Necessity in October, 2007. In June 2008, the FERC issued an order approving this application. Construction of this pipeline is expected to commence in September 2008, and the pipeline is expected to be in service by the second quarter of 2009. Total capital expenditures for the initial design of this project are estimated to be $1.45 billion. In July 2008, MEP completed an open season with respect to a capacity expansion of MEP from the original planned capacity of 1.5 Bcf/d to a total capacity of 1.8 Bcf/d for the main segment of the pipeline from north Texas to a planned interconnect location with the Columbia Gas Transmission Pipeline near Waverly, Louisiana. The additional 300,000 Mcf/d of capacity was fully subscribed as a result of this open season. The planned expansion of capacity would be effectuated through the installation of additional compression on this segment of the pipeline. This expansion project is subject to MEP s filing of an application with, and approval from, the FERC.

On February 29, 2008, MEP entered into a credit agreement that provides for a $1.4 billion senior revolving credit facility (the MEP Facility). We have guaranteed 50% of the obligations of MEP under the MEP Facility, with the remaining 50% of MEP Facility obligations guaranteed by KMP. Subject to certain exceptions, our guarantee may be proportionately increased or decreased if our ownership percentage increases or decreases. The MEP Facility is available through February 28, 2011. Amounts borrowed under the MEP Facility bear interest at a rate

Table of Contents

based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the MEP Facility varies based on both our credit rating and that of KMP, with a maximum fee of 0.15%. The MEP Facility also has a swingline loan option with a maximum borrowing of $25.0 million at a prime rate. The sum of the loans, swingline loans and letters of credit may not exceed the maximum amount of revolving credit available under the MEP Facility. The indebtedness under the MEP Facility is prepayable at any time at the option of MEP without penalty. The MEP Facility contains covenants that limit (subject to certain exceptions) MEP s ability to grant liens, incur indebtedness, engage in transactions with affiliates, enter into restrictive agreements, enter into mergers, or dispose of substantially all of its assets. As of June 30, 2008, MEP had $385.0 million of outstanding borrowings and $172.4 million of letters of credit issued under the MEP Facility. The weighted average interest rate on the total amount outstanding as of June 30, 2008 was 3.167%. The total amount available under the MEP Facility was $842.6 million as of June 30, 2008.

MEP also has a $197.0 million reimbursement agreement, under which MEP may issue letters of credit. We have guaranteed 50% of the obligations of MEP under the reimbursement agreement, with the remaining 50% guaranteed by KMP. As of June 30, 2008, MEP had $33.3 million of letters of credit issued under the reimbursement agreement.

In March 2008, MEP reimbursed ETP a net $63.5 million from the MEP facility for previous advances ETP made to MEP.

Commitments

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

We have certain non-cancelable leases for property and equipment which require fixed monthly rental payments and expire at various dates through 2020. Rental expense under these operating leases totaled approximately $7.2 million and $9.4 million for the three-month periods ended June 30, 2008 and May 31, 2007, respectively, and has been included in operating expenses in the accompanying condensed consolidated statements of operations. For the six-month periods ended June 30, 2008 and May 31, 2007, rental expense totaled approximately $15.4 million and $15.2 million, respectively, for operating leases.

Litigation and Contingencies

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

FERC/CFTC and Related Matters. On July 26, 2007, the FERC issued to us an Order to Show Cause and Notice of Proposed Penalties (the Order and Notice) that contains allegations that we violated FERC rules and regulations. The FERC has alleged that we engaged in manipulative or improper trading activities in the Houston Ship Channel, primarily on two dates during the fall of 2005 following the occurrence of Hurricanes Katrina and Rita, as well as on eight other occasions from December 2003 through August 2005, in order to benefit financially from our commodities derivatives positions and from certain of our index-priced physical gas purchases in the Houston Ship Channel. The FERC has alleged that during these periods we violated the FERC s then-effective Market Behavior Rule 2, an anti-market manipulation rule promulgated by the FERC under authority of the Natural Gas Act (NGA). We allegedly violated this rule by artificially suppressing prices that were included in the Platts *Inside FERC* Houston Ship Channel index, published by McGraw-Hill Companies, on which the pricing of many physical natural gas contracts and financial derivatives are based. Additionally, the FERC has alleged that we manipulated daily prices at the Waha and Permian Hubs in west Texas on two dates. Our Oasis pipeline transports interstate natural gas pursuant to Natural Gas Policy Act (NGPA) Section 311 authority and is subject to the FERC-approved rates, terms and conditions of service. The allegations related to the Oasis pipeline include claims that the Oasis pipeline violated NGPA regulations from January 26, 2004 through June 30, 2006 by granting undue preference to its affiliates for interstate NGPA Section 311 pipeline service to the detriment of similarly situated non-affiliated shippers and by charging in excess of the FERC-approved maximum lawful rate for interstate NGPA Section 311 transportation. The FERC also seeks to revoke, for a period of 12 months, our blanket marketing authority for sales of natural gas in interstate commerce at market-based prices, which activity is expected to account for approximately 1.0% of our operating income for our 2008 calendar year. If the FERC is successful in revoking our blanket marketing authority, our sales of natural gas at market-based prices would be limited to sales to retail customers (such as utilities and other end users) and sales from our own production, if any, and any other sales of natural gas by us would be required to be made at contract prices that would be subject to individual FERC approval.

In its Order and Notice, the FERC is seeking $70.1 million in disgorgement of profits, plus interest, and $97.5 million in civil penalties relating to these matters. The FERC has taken the position that, once it receives our response, it has several options as to how to proceed, including issuing an order on the merits, requesting briefs, or setting specified issues for a trial-type hearing before an administrative law judge. On August 27, 2007, ETP filed a request for rehearing of the Order and Notice. On December 20, 2007, the FERC issued an order denying rehearing and directed FERC Staff to file a brief recommending disposition of issues by order or by evidentiary hearing. ETP filed its response to the Order and Notice with the FERC on October 9, 2007, which response refuted the FERC s claims and requested a dismissal of the FERC proceeding. On February 14, 2008, the Enforcement Staff of the FERC filed a brief recommending that the FERC refer various matters relating to its market manipulation allegations for an evidentiary hearing before a FERC administrative law judge. The Enforcement Staff also recommended that FERC issue an order assessing the $15.5 million portion of the above-referenced penalty against ETP with respect to the allegations related to ETP s Oasis Pipeline and that the Oasis-related penalty assessment, if not paid, then be referred by the FERC to a federal district court for *de novo* review. The Enforcement Staff also recommended that the FERC impose certain changes in Oasis business operations and refunds to certain Oasis customers as previously proposed in the Order and Notice. Finally, the Enforcement Staff recommended that the FERC pursue market manipulation claims related to ETP s trading activities in October 2005, for November 2005 monthly deliveries, a period not previously covered by FERC s allegations in the Order and Notice, and that ETP be assessed an additional civil penalty of $25.0 million and be required to disgorge approximately $7.3 million of alleged unjust profits related to this additional month. If the FERC pursues the claims related to this additional month, the total amount of civil penalties and disgorgement of profits sought by the FERC would be approximately $200.0 million. On March 31, 2008, we responded to the Enforcement Staff s brief. On April 25, 2008, the Enforcement Staff filed an answer to our March 31, 2008 pleading. On May 15, 2008, the FERC ordered hearings to be conducted by FERC administrative law judges with respect to the FERC s Oasis claims and market manipulation claims. The hearing related to the Oasis claims is scheduled to commence in December 2008 with the administrative law judge s initial decision due by April 27, 2009 and the hearing related to the market manipulation claims is scheduled to commence in April 2009 with the administrative law judge s initial decision due by October 5, 2009. The FERC denied our request for dismissal of the proceeding and has ordered that, following the completion of the hearings, the administrative law judges make recommendations with respect to whether we engaged in market manipulation in violation of the NGA and FERC regulations and whether Oasis violated the NGPA and FERC regulations. The FERC reserved for itself the issues of possible civil penalties, revocation of our blanket market certificate, method by which we and Oasis would disgorge any unjust profits and whether any conditions should be placed on Oasis s Section 311 authorization. Following the issuance of each of the administrative law judge s initial decision, the FERC would then issue an order with respect to each of these matters. On May 23, 2008, we requested rehearing and stay of the FERC s May 15, 2008 order establishing hearing, and we renewed those requests on June 26, 2008. On August 7, 2008, FERC denied rehearing of its May 15, 2008 order. On August 8, 2008, we filed a petition with the U.S. Court of Appeals for the Fifth Circuit to review and set aside FERC s May 15 and August 7, 2008 orders on the grounds that we are entitled to adjudicate FERC s claims in federal district court pursuant to the NGA and the NGPA.

It is our position that our trading and transportation activities during the periods at issue complied in all material aspects with applicable law and regulations, and we intend to contest these cases vigorously. However, the laws and regulations related to alleged market manipulation are vague, subject to broad interpretation, and offer little guiding precedent, while at the same time the FERC holds substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

On July 26, 2007, the United States Commodity Futures Trading Commission (the CFTC) filed suit in United States District Court for the Northern District of Texas alleging that we violated provisions of the Commodity

Table of Contents

Exchange Act (the CEA) by attempting to manipulate natural gas prices in the Houston Ship Channel. On March 17, 2008, ETP entered into a consent order with the CFTC (the Consent Order). Pursuant to the Consent Order, ETP agreed to pay the CFTC $10.0 million and the CFTC agreed to release ETP and its affiliates, directors and employees from all claims or causes of action asserted by the CFTC in this proceeding. The Consent Order provides that ETP is permanently enjoined from attempting to manipulate the price of any commodity in interstate commerce in violation of the CEA. By consenting to the entry of the Consent Order, ETP neither admitted nor denied the allegations made by the CFTC in this proceeding. The settlement reduced our existing accrual and was paid from cash flow from operations in March 2008.

In addition to the FERC legal action, third parties have asserted claims and may assert additional claims against us and ETE for damages related to these matters. In this regard, several natural gas producers and a natural gas marketing company have initiated legal proceedings in Texas state courts against us and ETE for claims related to the FERC claims. These suits contain contract and tort claims relating to alleged manipulation of natural gas prices at the Houston Ship Channel and the Waha Hub in West Texas, as well as the natural gas price indices related to these markets and the Permian Basin natural gas price index during the period from December 2003 through December 2006, and seek unspecified direct, indirect, consequential and exemplary damages. One of the suits against us and ETE contains an additional allegation that the defendants transported gas in a manner that favored their affiliates and discriminated against the plaintiff, and otherwise artificially affected the market price of gas to other parties in the market. We have also been served with a complaint from an owner of royalty interests in natural gas producing properties, individually and on behalf of a putative class of similarly situated royalty owners, working interest owners and producers/operators, seeking arbitration to recover damages based on alleged manipulation of natural gas prices at the Houston Ship Channel. We have filed an original action in Harris County state court seeking a stay of the arbitration on the ground that the action is not arbitrable. The claimants have agreed to a stay of the arbitration pending briefing on cross-motions for summary judgment in the state court proceeding. Briefing on these cross-motions is expected to be completed on August 11, 2008, and a hearing on the cross-motions is set for August 29, 2008.

A consolidated class action complaint has been filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in intentional and unlawful manipulation of the price of natural gas futures and options contracts on the New York Mercantile Exchange, or NYMEX, in violation of the CEA. It is further alleged that during the class period December 29, 2003 to December 31, 2005, we had the market power to manipulate index prices, and that we used this market power to artificially depress the index prices at major natural gas trading hubs, including the Houston Ship Channel, in order to benefit our natural gas physical and financial trading positions and intentionally submitted price and volume trade information to trade publications. This complaint also alleges that we violated the CEA by knowingly aiding and abetting violations of the CEA. The plaintiffs state that this allegedly unlawful depression of index prices by us manipulated the NYMEX prices for natural gas futures and options contracts to artificial levels during the class period, causing unspecified damages to the plaintiffs and all other members of the putative class who sold natural gas futures or who purchased and/or sold natural gas options contracts on NYMEX during the class period. The plaintiffs have requested certification of their suit as a class action, and seek unspecified damages, court costs and other appropriate relief. On January 14, 2008, we filed a motion to dismiss this suit on the grounds of failure to allege facts sufficient to state a claim. On March 20, 2008, the plaintiffs filed a second consolidated class action complaint. In response to this new pleading, on May 5, 2008 we filed a motion to dismiss the complaint. On June 19, 2008 the plaintiffs filed a response opposing our motion to dismiss.

On March 17, 2008, a second class action complaint was filed against us in the United States District Court for the Southern District of Texas. This action alleges that we engaged in unlawful restraint of trade and intentional monopolization and attempted monopolization of the market for fixed-price natural gas baseload transactions at the Houston Ship Channel from December 2003 through December 2005 in violation of federal antitrust law. The complaint further alleges that during this period we exerted monopoly power to suppress the price for these transactions to non-competitive levels in order to benefit from our own physical natural gas positions. The plaintiff has, individually and on behalf of all other similarly situated sellers of physical natural gas, requested certification of its suit as a class action and seeks unspecified treble damages, court costs and other appropriate relief. On May 19, 2008, we filed a motion to dismiss this complaint.

We are expensing the legal fees, consultants fees and other expenses relating to these matters in the periods in which such expenses are incurred. In addition, our existing accruals for litigation and contingencies include an accrual related to these matters. At this time, we are unable to predict the outcome of these matters; however, it is possible that the amount we become obliged to pay as a result of the final resolution of these matters, whether on a

Table of Contents

negotiated settlement basis or otherwise, will exceed the amount of our accrual related to these matters. In accordance with applicable accounting standards, we will review the amount of our accrual related to these matters as developments related to these matters occur and we will adjust our accrual if we determine that it is probable that the amount we may ultimately become obliged to pay as a result of the final resolution of these matters is greater than the amount of our existing accrual for these matters. As our accrual amounts are non-cash, any cash payment of an amount in resolution of these matters would likely be made from cash from operations or borrowings, which payments would reduce our cash available for distributions either directly or as a result of increased principal and interest payments necessary to service any borrowings incurred to finance such payments. If these payments are substantial, we may experience a material adverse impact on our results of operations, cash available for distribution and our liquidity.

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

Houston Pipeline Cushion Gas Litigation. At the time of the HPL System acquisition, AEP Energy Services Gas Holding Company II, L.L.C., HPL Consolidation LP and its subsidiaries (the HPL Entities), their parent companies and American Electric Power Corporation (AEP), were engaged in ongoing litigation with Bank of America (B of A) that related to AEP s acquisition of HPL in the Enron bankruptcy and B of A s financing of cushion gas stored in the Bammel Storage Facility (Cushion Gas). This litigation is referred to as the Cushion Gas Litigation . Under the terms of the Purchase and Sale Agreement and the related Cushion Gas Litigation Agreement, AEP and its subsidiaries that were the sellers of the HPL Entities retained control of the Cushion Gas Litigation and have agreed to indemnify ETC OLP and the HPL Entities for any damages arising from the Cushion Gas Litigation and the loss of use of the Cushion Gas, up to a maximum of the amount paid by ETC OLP for the HPL Entities and the working gas inventory (approximately $1.0 billion in the aggregate). The Cushion Gas Litigation Agreement terminates upon final resolution of the Cushion Gas Litigation. In addition, under the terms of the Purchase and Sale Agreement, AEP retained control of additional matters relating to ongoing litigation and environmental remediation and agreed to bear the costs of or indemnify ETC OLP and the HPL Entities for the costs related to such matters. On December 18, 2007, the United States District Court for the Southern District of New York held that B of A is entitled to receive monetary damages from AEP and the HPL Entities of approximately $347.3 million less the monetary amount B of A would have incurred to remove 55 Bcf of natural gas from the Bammel Storage Facility. AEP filed a notice of motion for reconsideration questioning the court s damages calculation. AEP will determine whether it will appeal the court decision once a final judgment is entered. Based on the indemnification provisions of the Cushion Gas Litigation Agreement, ETP does not expect that it will be liable for any portion of this court award.

Other Matters. In addition to those matters described above, we or our subsidiaries are a party to various legal proceedings and/or regulatory proceedings incidental to our businesses. For each of these matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies, the likelihood of an unfavorable outcome and the availability of insurance coverage. If we determine that an unfavorable outcome of a particular matter is probable, can be estimated and is not covered by insurance, we make an accrual for the matter. For matters that are covered by insurance, we accrue the related deductible. As 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.

Table of Contents

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

As of June 30, 2008 and December 31, 2007, an accrual of $20.4 million and $30.5 million, respectively, was recorded as accrued and other current liabilities and other non-current liabilities on our condensed consolidated balance sheets for our contingencies and current litigation matters, excluding accruals related to environmental matters.

Environmental

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

Transwestern conducts soil and groundwater remediation at a number of its facilities. Some of the clean up activities include historical remediation obligations at 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 through 2018 is $10.1 million. Transwestern received FERC approval for rate recovery of the portion of soil and groundwater remediation not related to PCBs effective April 1, 2007.

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

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

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 amount has been recorded in our June 30, 2008 or our December 31, 2007 condensed consolidated balance sheets. Based on information currently available to us, such projects are not expected to have a material adverse effect on our financial condition or results of operations.

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

As of June 30, 2008 and December 31, 2007, an accrual on an undiscounted basis of $14.2 million and $15.7 million 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.

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

Our pipeline operations are subject to regulation by the U.S Department of Transportation (DOT) under the Pipeline Hazardous Materials Safety Administration (PHMSA) pursuant to which the PHMSA has established regulations relating to the design, installation, testing, construction, operation, replacement and management of pipeline facilities. Moreover, the PHMSA, through the Office of Pipeline Safety, has promulgated a rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the rule refers to as high consequence areas. Through June 30, 2008, Transwestern did not incur any costs associated with the IMP Rule and has satisfied all of the requirements until 2010. Through June 30, 2008, a total of $4.0 million of capital costs and $10.4 million of operating and maintenance costs have been incurred for pipeline integrity testing for our transportation assets other than Transwestern. Through June 30, 2008, a total of $1.5 million of capital costs and $0.3 million of operating and maintenance costs have been incurred for pipeline integrity costs for Transwestern. Integrity testing and assessment of all of these assets will continue, and the potential exists that results of such testing and assessment could cause us to incur even greater capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of its pipelines.

13. PRICE RISK MANAGEMENT ASSETS AND LIABILITIES:

Accounting for Derivative Instruments and Hedging Activities

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. 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 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.

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.

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

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 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 condensed consolidated balance sheets. 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. Furthermore, management reviews the creditworthiness of the derivative counterparties to manage against the risk of default on a weekly basis.

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 $60.4 million and $42.2 million as of June 30, 2008 and December 31, 2007, respectively, reflected as deposits paid to vendors on our condensed consolidated balance sheets.

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

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 condensed consolidated statements of operations. We reclassified into earnings losses of $9.7 million and gains of $20.2 million for the three months ended June 30, 2008 and May 31, 2007, respectively, and gains of $12.8 million and $139.8 million for the six months ended June 30, 2008 and May 31, 2007, respectively, related to commodity financial instruments that were previously reported in OCI.

We expect gains of $3.4 million related to commodity derivatives to be reclassified into earnings over the next twelve months related to income currently reported in OCI. The amount ultimately realized, however, will differ as commodity prices change and the underlying physical transaction occurs.

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.

Trading Activities

Trading activities are monitored independently by our risk management function and must take place within predefined limits and authorizations. Certain activities where limited market risk is assumed 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 condensed consolidated balance sheets at fair value, and changes in the fair value of these derivative instruments are recognized in midstream and intrastate transportation and storage revenue in the condensed consolidated statements of operations on a net basis.

Due to the high level of market volatility experienced in recent months as well as other business considerations, as of July 2008 the Partnership determined that it will no longer engage in the trading of financial derivative instruments that are not offset by physical positions. As a result, the Partnership will no longer have any material exposure to market risk from such derivative positions. Trading activities, including trading of physical gas and financial derivative instruments, resulted in net losses of approximately $26.1 million for the year-to-date period through July 31, 2008, net gains of approximately $2.2 million for the fiscal year ended August 31, 2007 and net losses of approximately $2.3 million for the four-month transition period ended December 31, 2007.

The following table details the outstanding commodity-related derivatives and their fair values as of June 30, 2008 and December 31, 2007, respectively:

June 30, 2008

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	16,110,000	2008-2011	$ 97
Swing Swaps IFERC	Gas	(12,607,000)	2008-2009	(500)
Fixed Swaps/Futures	Gas	(10,165,000)	2008-2009	(28,523)
Forward Physical Contracts	Gas	(7,222,084)	2008	(449)
Options	Gas	(306,000)	2008	(1)
Forwards/Swaps in Gallons	Propane	28,560,000	2008-2009	6,649
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(16,867,500)	2008-2009	$ 5,177
Cash Flow Hedging Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	1,372,500	2008-2009	$ (163)
Fixed Swaps/Futures	Gas	1,372,500	2008-2009	6,773

December 31, 2007

	Commodity	Notional Volume MMBTU	Maturity	Fair Value Asset (Liability)
Mark to Market Derivatives				
(Non-Trading)				
Basis Swaps IFERC/NYMEX	Gas	2,732,500	2008-2009	$ (2,767)
Swing Swaps IFERC	Gas	(4,640,000)	2008	(1,515)
Fixed Swaps/Futures	Gas	(26,987,500)	2008-2009	14,230
Forward Physical Contracts	Gas	(17,847,140)	2008	(1,063)
Options	Gas	(670,000)	2008	(161)
Forward/Swaps in Gallons	Propane	9,282,000	2008	3,319
(Trading)				
Basis Swaps IFERC/NYMEX	Gas	(18,362,500)	2008	$ 2,298
Cash Flow Hedging Derivatives				
(Non-Trading)				

Basis Swaps IFERC/NYMEX	Gas	(11,255,000)	2008-2009	$	(1,262)
Fixed Swaps/Futures	Gas	(13,120,000)	2008-2009		26,913

Table of Contents

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, are expected to be offset with financial contracts to balance our positions. To the extent open commodity positions exist in our trading and non-trading activities, fluctuating commodity prices can impact our financial results and financial position, either favorably or unfavorably.

During the six months ended June 30, 2008 and May 31, 2007, the Partnership discontinued application of hedge accounting in connection with certain derivative financial instruments that were qualified 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 2007 for the 2007 period and unfavorable market conditions for the 2008 period. 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 six months ended June 30, 2008 and May 31, 2007, the Partnership recognized previously deferred unrealized losses of $10.3 million and unrealized gains of $37.2 million from the discontinued application of hedge accounting, which is included in the reclassification into earnings from OCI. The Partnership classified the unrealized gains as costs of products sold in its condensed consolidated statement of operations.

Interest Rate Risk

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

The following table represents interest rate swap derivatives and their fair values as of June 30, 2008 and December 31, 2007:

				Fair Value Liability as of	
Term	**Notional Amount**	**Type**	**SFAS 133 Hedge**	**June 30, 2008**	**December 31, 2007**
March 2009	$ 125,000	Pay Fixed 5.14% Receive Float	No	$ 2,086	$ 1,530

We reclassified into earnings, gains of $0.5 million and gains of $1.5 million for the six months ended June 30, 2008 and May 31, 2007, respectively, related to interest rate swaps that were previously reported in OCI. We expect gains of $0.3 million to be reclassified into earnings over the next twelve months related to income on interest rate financial instruments currently reported in OCI. For the three months ended June 30, 2008 and May 31, 2007, respectively, we reclassified into earnings, gains of $0.2 million and losses of $1.2 million related to interest rate swaps that were previously reported in OCI.

34

Table of Contents

The following table represents pre-tax balances in OCI related to interest rate swaps accounted for as cash flow hedges as of June 30, 2008 and December 31, 2007:

Date Settled	Term	Notional Amount	Type	Accumulated Other Comprehesive Income (Loss) as of June 30, 2008	Accumulated Other Comprehesive Income (Loss) as of December 31, 2007
April 2007	2014	$ 400,000	LIBOR Forward Starting	$ (11,063)	$ (11,135)
June 2006	2016	200,000	Treasury Lock	11,620	12,210
January 2005	2017	100,000	Treasury Lock	(252)	(269)
				$ 305	$ 806

Summary of Derivative Gains and Losses

The following represents gains (losses) on derivative activity recognized in net income for the periods presented:

	Three Months Ended June 30, 2008	Three Months Ended May 31, 2007	Six Months Ended June 30, 2008	Six Months Ended May 31, 2007
Commodity-related				
Unrealized non-trading losses recognized in cost of products sold related to commodity-related derivative activity, excluding ineffectiveness	$ (14,723)	$ (23,444)	$ (34,770)	$ 6,703
Ineffective portion of derivatives qualifying for hedge accounting recognized in cost of products sold	(16)	(1,240)	(8,336)	(2,343)
Realized non-trading gains (losses) related to commodity-related derivatives included in cost of products sold	(33,698)	49,900	(27,625)	147,503
Unrealized trading gains recognized in revenues	8,714	(2,282)	2,879	(8,611)
Realized trading gains recognized in revenues	425	2,771	5,568	8,056
Interest rate swaps				
Unrealized gains (losses) on non-hedged interest rate swaps included in other income	$ 1,225	$ 16,328	(556)	$ 16,667
Ineffective portion of derivatives qualifying for hedge accounting included in interest expense		(1,377)		1,012
Realized gains (losses) on interest rate swaps included in interest expense and other income	(654)	346	812	690

Credit Risk

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

Our counterparties consist primarily of financial institutions, major energy companies and local distribution companies. This concentration of counterparties may impact 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.

Table of Contents

14. RELATED PARTY TRANSACTIONS:

During the three and six months ended June 30, 2008, we made the following sales to and purchases from affiliates of Enterprise G.P. Holdings, L.P. (Enterprise):

Enterprise Transactions	Product	Volumes (in thousands)	Dollars
Three Months Ended June 30, 2008:			
Propane Operations -			
Purchases	Propane - gallons	24,743	$ 74,492
Natural Gas Operations -			
Sales	NGLs - gallons	8,591	$ 14,754
	Natural Gas - MMBtu	1,430	13,817
	Fees		1,486
Purchases	Natural Gas Imbalances - MMBtu	2,775	$ 7,608
	Natural Gas - MMBtu	7,738	32,201
	Fees		257
Six Months Ended June 30, 2008:			
Propane Operations -			
Purchases	Propane - gallons	163,555	$ 270,584
Natural Gas Operations -			
Sales	NGLs - gallons	15,977	$ 24,913
	Natural Gas - MMBtu	3,032	26,678
	Fees		3,158
Purchases	Natural Gas Imbalances - MMBtu	1,981	$ 2,920
	Natural Gas - MMBtu	5,329	51,973
	Fees		512

Between May 7, 2007 (the date Enterprise became an affiliate) and May 31, 2007, we made the following purchases from Enterprise and its affiliates:

	Product	Volumes (in thousands)	Dollars
Propane Operations	Propane -gallons	12,371	$ 13,462
Natural Gas Operations	Natural gas imbalances - MMBtu	185	1,905
			$ 15,367

Accounts receivable from and accounts payable to related companies as of June 30, 2008 and December 31, 2007 relate primarily to activities in the normal course of business.

From time to time, we enter into commodity financial instrument contracts for which Enterprise or its affiliates are the counterparty. During the three and six months ended June 30, 2008, we recognized gains of $6.0 million and $5.2 million, respectively, in net income. As of June 30, 2008, derivative assets with a total fair value of $6.2 million are outstanding with Enterprise. Comparative amounts for 2007 were not significant.

ETC OLP and Enterprise transport natural gas on each other s pipelines, share operating expenses on jointly-owned pipelines, and ETC OLP sells natural gas to Enterprise. Our propane operations routinely buy and sell product with Enterprise. The following table summarizes the related party balances with Enterprise on our condensed consolidated balance sheets:

36

	June 30, 2008	December 31, 2007
Natural Gas Operations:		
Accounts receivable	$ 10,554	$ 9,770
Accounts payable	11,003	6,840
Imbalance payable	9,137	6,218
Propane Operations:		
Accounts receivable	$ 858	$ 3,396
Accounts payable	13,544	41,939

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

	June 30, 2008	December 31, 2007
ETP GP	$ 144	$ 5,113
ETE	2,529	1,553
MEP	4,914	743
Energy Transfer Technologies, Ltd.		922
Others	530	2,941
Total accounts receivable from related companies excluding Enterprise	$ 8,117	$ 11,272

Effective October 19, 2007, the Chief Executive Officer (CEO) of our General Partner, Mr. Kelcy Warren, voluntarily determined that his salary would be reduced to $1.00 plus an amount sufficient to cover his allocated payroll deductions for health and welfare benefits. Mr. Warren also declined future cash bonuses and future equity awards under our 2004 Unit Plan. In accordance with GAAP, we recorded compensation expense and an offsetting capital contribution of $0.6 million ($0.2 million in salary and $0.4 million in accrued bonuses) for the six months ended June 30, 2008 as an estimate of the reasonable compensation level for the CEO position.

15. REPORTABLE SEGMENTS:

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

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

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

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

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. We allocate administration expenses from the Partnership to our Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC) which is based on factors such as respective segments gross margins, employee costs, and property and equipment. The expenses subject to allocation are based on estimated amounts and take into consideration actual expenses from previous months and known trends. The difference between the allocation and actual costs is adjusted in the following month. The amounts allocated for the three and six months ended June 30, 2008 and May 31, 2007 are as follows:

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Allocated from ETP to Operating Partnerships:				
Midstream and Intrastate transportation Operations	$ 4,688	$ 3,274	$ 8,585	$ 7,143
Interstate Operations	1,353	1,265	2,506	2,760
Propane Operations	2,975	2,902	5,525	6,331
Total	$ 9,016	$ 7,441	$ 16,616	$ 16,234
Costs allocated from Operating Partnerships to ETP:				
Midstream and Intrastate transportation Operations	$ 2,560	$ 2,103	$ 3,933	$ 4,283
Propane Operations	752	670	1,353	1,610
Total	$ 3,312	$ 2,773	$ 5,286	$ 5,893

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

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Revenues:				
Midstream	$ 1,874,420	$ 869,079	$ 3,120,184	$ 1,493,324
Eliminations	(1,430,252)	(488,188)	(2,204,426)	(785,808)
Intrastate transportation and storage	1,872,245	963,993	3,353,086	2,072,048
Interstate transportation	59,224	61,714	114,640	119,872
Retail propane and other retail propane related	273,660	276,445	899,375	806,000
All other	4,179	31,743	9,988	71,830
Total revenues	$ 2,653,476	$ 1,714,786	$ 5,292,847	$ 3,777,266
Cost of Products Sold:				
Midstream	$ 1,768,161	$ 812,815	$ 2,919,131	$ 1,386,527
Eliminations	(1,430,252)	(488,188)	(2,204,426)	(785,808)
Intrastate transportation and storage	1,614,660	770,413	2,815,132	1,633,030
Retail propane and other retail propane related	168,282	163,500	566,013	474,864
All other	3,221	28,847	7,940	64,590
Total cost of products sold	$ 2,124,072	$ 1,287,387	$ 4,103,790	$ 2,773,203
Depreciation and Amortization:				
Midstream	$ 13,489	$ 6,226	$ 27,335	$ 11,791
Intrastate transportation and storage	20,022	14,467	36,473	26,479
Interstate transportation	9,266	9,241	18,566	18,895
Retail propane and other retail propane related	19,487	17,306	38,573	35,243
All other	157	162	302	354
Total depreciation and amortization	$ 62,421	$ 47,402	$ 121,249	$ 92,762

Table of Contents

	Three Months Ended		Six Months Ended	
	June 30, 2008	May 31, 2007	June 30, 2008	May 31, 2007
Operating Income (Loss):				
Midstream	$ 65,26			