Kerin Matthew A
Form 4
March 08, 2011

FORM 4

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

OMB APPROVAL

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Check this box if no longer subject to Section 16. Form 4 or Form 5 obligations may continue. *See* Instruction 1(b).

STATEMENT OF CHANGES IN BENEFICIAL OWNERSHIP OF SECURITIES

Filed pursuant to Section 16(a) of the Securities Exchange Act of 1934, Section 17(a) of the Public Utility Holding Company Act of 1935 or Section 30(h) of the Investment Company Act of 1940

(Print or Type Responses)

1. Name and Address of Reporting Person *
Kerin Matthew A

(Last) (First) (Middle)

C/O FLAGSTAR BANCORP, INC., 5151 CORPORATE DRIVE

(Street)

TROY, MI 48098

(City) (State) (Zip)

2. Issuer Name **and** Ticker or Trading Symbol
FLAGSTAR BANCORP INC [(NYSE:FBC)]

3. Date of Earliest Transaction (Month/Day/Year)
03/04/2011

4. If Amendment, Date Original Filed(Month/Day/Year)

5. Relationship of Reporting Person(s) to Issuer

(Check all applicable)

_____ Director _____ 10% Owner
__X__ Officer (give title below) _____ Other (specify below)
Executive Vice-President

6. Individual or Joint/Group Filing(Check Applicable Line)
_X_ Form filed by One Reporting Person
___ Form filed by More than One Reporting Person

Table I - Non-Derivative Securities Acquired, Disposed of, or Beneficially Owned

1.Title of Security (Instr. 3)	2. Transaction Date (Month/Day/Year)	2A. Deemed Execution Date, if any (Month/Day/Year)	3. Transaction Code (Instr. 8)		4. Securities Acquired (A) or Disposed of (D) (Instr. 3, 4 and 5)			5. Amount of Securities Beneficially Owned Following Reported Transaction(s) (Instr. 3 and 4)	6. Ownership Form: Direct (D) or Indirect (I) (Instr. 4)	7. Nature of Indirect Beneficial Ownership (Instr. 4)
			Code	V	Amount	(A) or (D)	Price			
Flagstar Bancorp, Inc. Common Stock	03/04/2011		A		6,446	A	$ 0 (1)	441,780	D	
Flagstar Bancorp, Inc. Common Stock	03/04/2011		F		2,994	D	$ 1.79	438,786	D	

Reminder: Report on a separate line for each class of securities beneficially owned directly or indirectly.

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SEC 1474 (9-02)

Table II - Derivative Securities Acquired, Disposed of, or Beneficially Owned
(*e.g.*, puts, calls, warrants, options, convertible securities)

1. Title of Derivative Security (Instr. 3)	2. Conversion or Exercise Price of Derivative Security	3. Transaction Date (Month/Day/Year)	3A. Deemed Execution Date, if any (Month/Day/Year)	4. Transaction Code (Instr. 8)		5. Number of Derivative Securities Acquired (A) or Disposed of (D) (Instr. 3, 4, and 5)		6. Date Exercisable and Expiration Date (Month/Day/Year)		7. Title and Amount of Underlying Securities (Instr. 3 and 4)		8. Price of Derivative Security (Instr. 5)	9. Nu Deriv Secur Bene Owne Follo Repo Trans (Instr
				Code	V	(A)	(D)	Date Exercisable	Expiration Date	Title	Amount or Number of Shares		

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
Kerin Matthew A C/O FLAGSTAR BANCORP, INC. 5151 CORPORATE DRIVE TROY, MI 48098			Executive Vice-President	

Signatures

/s/ Matthew A. Kerin	03/08/2011
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Securities are base salary paid to Mr. Kerin in the form of shares of the Flagstar Bancorp, Inc. Common Stock as further described in the Company's Current Report on Form 8-K filed on December 8, 2009.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. TD> **Increase 2007 2006**

Natural gas MMBtu/d - sold

1,090,090	968,016	122,074

NGLs Bbls/d - sold

25,389	12,458	12,931

Natural gas sales volumes increased principally due to more favorable market conditions during the four months ended December 31, 2007 resulting in higher sales volumes conducted by our producer services operations.

The increase in NGL sales volumes is principally due to the completion of our Godley processing plant in October 2006 and the continued expansion of the plant since placing it into service. As of December 31, 2007, the Godley plant had approximately 300,000 MMcf/d of cryoprocessing capacity and 100,000 MMcf/d of refrigeration processing capacity.

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Intrastate Transportation and Storage

	Four Months Ended December 31, 2007	2006	Increase (Decrease)
Natural gas MMBtu/d - transported	8,787,387	4,889,029	3,898,358
Natural gas MMBtu/d - sold	1,259,566	1,379,721	(120,155)

Transported natural gas volumes increased principally due to the increased volumes experienced on the ET Fuel and East Texas Pipeline systems as a result of the completion of the Cleburne to Carthage Pipeline, increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, and the continued effort to secure long-term shipper contracts.

Natural gas sales volumes on the HPL System decreased primarily due to the new CenterPoint contract that commenced on April 1, 2007. Under the previous contract, we sold and delivered natural gas to CenterPoint for a bundled price. Under the terms of the new agreement, CenterPoint has contracted for 129 Bcf per year of firm transportation capacity combined with 10 Bcf of working gas capacity in our Bammel storage facility.

Interstate Transportation

	Four Months Ended December 31, 2007	2006	Decrease
Natural gas MMBtu/d - transported	1,708,477	1,791,437	(82,960)

The four months ended December 31, 2006 only include volumes transported from the acquisition date of December 1, 2006 to December 31, 2006.

Retail Propane

	Four Months Ended December 31, 2007	2006	Decrease
Retail propane gallons sold (in thousands)	205,311	214,623	(9,312)

Total gallons sold by our retail propane operations decreased due to a combination of below normal degree days, customer conservation, and the slow down of new home construction in our propane markets. The overall weather in our areas of operations during the four months ended December 31, 2007 was 2.9% warmer than the four months ended December 31, 2006 and 9.8% warmer than normal.

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Analysis of Results of Operations

Consolidated Results

	Four Months Ended December 31, 2007	2006	Change
Revenues	$ 2,349,510	$ 2,162,466	$ 187,044
Cost of sales	1,673,654	1,689,843	(16,189)
Gross margin	675,856	472,623	203,233
Operating expenses	221,757	173,365	48,392
Selling, general and administrative	59,132	40,603	18,529
Depreciation and amortization	71,333	48,767	22,566
Operating income	323,634	209,888	113,746
Interest expense	(66,298)	(54,946)	(11,352)
Equity in earnings (losses) of affiliates	(94)	4,743	(4,837)
Gain on disposal of assets	14,310	2,212	12,098
Other income, net	1,061	2,158	(1,097)
Income tax expense	(10,789)	(3,120)	(7,669)
Minority interests		(490)	490
Net income	$ 261,824	$ 160,445	$ 101,379

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

Interest Expense. Interest expense increased $11.4 million principally due to a net $13.8 million increase in interest expense related to borrowings on the Partnership s Senior Notes and the revolving credit facility and $0.5 million of interest on borrowings related to the Transwestern acquisition. Partnership borrowings increased primarily due to the financing of our growth capital expenditures and the Canyon acquisition. The increased interest expense was offset by $2.0 million of unrealized losses related to non-hedged interest rate swaps included in interest expense for the four months ended December 31, 2006. Unrealized gains and losses related to non-hedged interest rate swaps were included in other income, net for the four months ended December 31, 2007. The increase in interest expense was also offset by propane related interest which decreased $2.0 million due primarily to the scheduled debt payments that have occurred between the four-month periods.

Equity in Earnings of Affiliates. The decrease in equity in earnings (losses) of affiliates was due primarily to $5.1 million of equity income from our 50% ownership of CCEH for the month of November 2006. We redeemed our investment in CCEH in connection with our Transwestern acquisition on December 1, 2006. We do not include earnings from equity method unconsolidated affiliates in our measurement of operating income because such earnings have not been significant historically.

Gain on Sale of Assets. On October 1, 2007 we sold our 60% interest in a Canadian wholesale fuel business for a gain of $10.2 million.

Income Tax Expense. As a partnership, we are generally not subject to income taxes. However, certain wholly-owned subsidiaries are corporations that are subject to income taxes.

The increase in income tax expense was primarily related to $3.9 million recorded for the four months ended December 31, 2007 of Texas margin tax that was not effective until January 1, 2007 and $3.9 million of taxes on the gain on the sale of our interest in a Canadian wholesale fuel business.

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Segment Operating Results

Operating income by segment is as follows:

	Four Months Ended December 31, 2007	2006	Change
Midstream	$ 73,167	$ 41,735	$ 31,432
Intrastate Transportation and Storage	172,120	112,021	60,099
Interstate Transportation	29,657	11,854	17,803
Retail Propane	46,747	49,841	(3,094)
Other	(628)	528	(1,156)
Unallocated selling, general and administrative expenses	2,571	(6,091)	8,662
Operating income	$ 323,634	$ 209,888	$ 113,746

We do not believe the Other operating income is material for further disclosure or discussion.

Unallocated Selling, General and Administrative Expenses. Prior to December 2006, the selling, general and administrative expenses that relate to the general operations of the Partnership were not allocated to our segments. In conjunction with the Transwestern acquisition, selling, general and administrative expenses are now allocated monthly to the Operating Partnerships using the Modified Massachusetts Formula Calculation (MMFC). 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. For the four months ended December 31, 2007, a net $12.1 million allocation to the Operating Partnerships exceeded total incurred costs.

Midstream

	Four Months Ended December 31, 2007	2006	Change
Revenues	$ 1,166,313	$ 905,392	$ 260,921
Cost of sales	1,043,191	839,561	203,630
Gross margin	123,122	65,831	57,291
Operating expenses	17,633	11,710	5,923
Selling, general and administrative	18,693	5,952	12,741
Depreciation and amortization	13,629	6,434	7,195
Segment operating income	$ 73,167	$ 41,735	$ 31,432

Gross Margin. Midstream s gross margin increased by $57.3 million primarily due to the following factors:

Increases in processing margin of $37.6 million and fee-based revenue of $17.9 million from our gathering and processing assets. The increase was due to incremental volumes from the completion of our Godley plant in October 2006, the continued expansion of the plant since placing it into service, and the acquisition of three gathering systems during the first six months of the 2007 fiscal year. In addition, our midstream assets benefited from favorable market conditions to process and extract NGLs during the four months ended December 31, 2007. Due to changes in the contract structures at our Godley plant in November 2007, arrangements for which we had been recognizing the increased margin from favorable conditions will convert to long-term fee-based arrangements. As such, we expect margin from processing at our Godley plant to be more predictable and less sensitive to commodity price volatility;

Increase in non-trading margin from our marketing activities of $1.0 million. Market conditions resulted in higher sales volumes conducted by our producer services operations;

Decrease in net trading revenues of $5.2 million; and,

Canyon Gathering System The acquisition of the Canyon Gathering System on October 5, 2007 contributed approximately $5.6 million of incremental margin for the four months ended December 31, 2007.

Operating Expenses. Midstream operating expenses increased $5.9 million, primarily driven by increased employee-related costs such as salaries, incentive compensation and healthcare costs of $2.2 million, increased compressor rentals of $1.5 million, and increased pipeline and compressor maintenance expense of $0.7 million. The increases were principally due to the gathering system acquisitions in fiscal 2007, the start up and continued expansion of the Godley plant, and the Canyon acquisition.

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Selling, General and Administrative Expenses. Midstream selling, general and administrative expenses increased $12.7 million which was attributable to $9.2 million in increased legal fees principally related to regulatory matters, a $4.2 million allocation of parent company administrative expenses for overhead costs which previously had not been allocated in 2006, and a $1.9 million increase in employee-related costs such as salaries, incentive compensation and healthcare costs. These factors were offset by a $5.8 million increase of general and administrative expenses allocated to the transportation segment. The allocation of general and administrative expenses between the midstream and the intrastate transportation and storage segments is based on the MMFC and is intended to fairly present the segment s operating results.

Depreciation and Amortization. Midstream depreciation and amortization expense increased $7.2 million principally due to additions to property and equipment including the completion and continued expansion of our Godley plant, and the acquisition of certain gathering system in December of 2006.

Intrastate Transportation and Storage

	Four Months Ended December 31, 2007	2006	Change
Revenues	$ 1,254,401	$ 1,195,871	$ 58,530
Cost of sales	964,568	994,511	(29,943)
Gross margin	289,833	201,360	88,473
Operating expenses	76,428	56,452	19,976
Selling, general and administrative	20,615	16,626	3,989
Depreciation and amortization	20,670	16,261	4,409
Segment operating income	$ 172,120	$ 112,021	$ 60,099

Gross Margin. Intrastate transportation and storage gross margin increased by $88.5 million, principally due to the following factors:

Volumes. Overall volumes on our transportation pipelines were higher due to the completion of the Clebourne to Carthage Pipeline, increased demand to transport natural gas out of the Barnett Shale and Bossier Sands producing regions, continued efforts to secure long-term shipper contracts, and the completion of various growth projects subsequent to December 31, 2006. Transportation fees increased approximately $53.2 million. Retention revenue increased approximately $29.7 million due to increased volumes transported through our transportation pipelines;

Increase in processing margin of $8.6 million from our HPL system. Processing margins generated from our HPL system benefited from favorable market conditions to process and extract NGLs during the four months ended December 31, 2007; and

Net decrease in storage margins of $9.4 million. During the four months ended December 31, 2006, we recognized approximately $27.0 million of margin on 13 Bcf of gas sold from our Bammel facility. Due to market conditions, there were no withdrawals in the same period in 2007; however, we did recognize $9.2 million in gains from the discontinuation of hedge accounting resulting from our determination that originally forecasted sales of natural gas from the Partnership s Bammel storage facility were no longer probable to occur by the specified time period, or within an additional two-month time period thereafter. In addition, fee-based storage revenues increased $8.4 million primarily due to the new Centerpoint contract which commenced on April 1, 2007 in which Centerpoint contracted for 10 Bcf of working gas capacity in our Bammel storage facility.

Operating Expenses. Intrastate transportation and storage operating expenses increased $20.0 million primarily due to an increase of $11.4 million in fuel consumption, an increase of $4.5 million in electricity costs, an increase of $6.1 million in compressor and pipeline maintenance, and an increase of $2.0 million in employee related costs such as salaries, incentive compensation and healthcare costs. These increases were offset by a $2.8 million decrease in compressor rentals and a $2.9 million decrease in professional fees related to the EMS contract buyout in September 2007.

Selling, General and Administrative Expenses. Intrastate transportation and storage selling, general and administrative expenses increased $4.0 million principally due to an increase in general and administrative expenses allocated from the midstream segment as noted above.

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Depreciation and Amortization. Intrastate transportation and storage depreciation and amortization expense increased $4.4 million principally due to additions to property and equipment most notably the Clebourne to Carthage Pipeline.

Interstate Transportation

	Four Months Ended December 31,		
	2007	2006	Change
Revenues	$ 76,000	$ 19,003	$ 56,997
Operating expenses	23,922	1,396	22,526
Selling, general and administrative	10,116	2,562	7,554
Depreciation and amortization	12,305	3,191	9,114
Segment operating income	$ 29,657	$ 11,854	$ 17,803

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

Retail Propane

	Four Months Ended December 31,		
	2007	2006	Change
Retail propane revenues	$ 471,494	$ 409,821	$ 61,673
Other retail propane related revenues	39,764	40,020	(256)
Retail propane cost of sales	315,698	256,994	58,704
Other retail propane related cost of sales	9,460	10,344	(884)
Gross margin	186,100	182,503	3,597
Operating expenses	102,537	101,508	1,029
Selling, general and administrative	12,279	8,634	3,645
Depreciation and amortization	24,537	22,520	2,017
Segment operating income	$ 46,747	$ 49,841	$ (3,094)

Revenues. Retail propane revenues increased $61.7 million mainly due to increased sale prices driven by the increased cost of fuel. This increase was offset by 9.8% warmer than normal weather and 2.9% warmer weather than the same period last year.

Costs of Sales. Retail propane cost of sales increased by $58.7 million mainly related to the increase in overall cost of fuel to the company offset by the decrease in gallons sold. On an average, fuel costs were approximately $0.35/gallon higher.

Gross Margin. Overall gross margins increased $3.6 million even though gallon sales decreased. The propane margin remained strong despite warmer weather conditions and higher fuel prices. Optimization of the margins is influenced by market opportunities, independent competitors and concerns for long term retention of customers.

Operating Expenses. Operating expenses increased by $1.0 million. Included in these operating expenses were increases related to higher vehicle fuel costs and other vehicle expenses, offset by the cost conservation efforts of the retail operations and the delay in hiring seasonal staff due to the warmer weather.

Selling, General and Administrative Expenses. The increase in selling, general and administrative expenses was primarily due to increased administrative expense allocations. Effective with the Transwestern acquisition in December 2006, an allocation of general and administrative expenses based on the MMFC is now made to the operating partnerships, which increased the retail propane selling, general and administrative expenses by a net $5.1 million for the four months ended December 31, 2007. This increase from the allocation of expenses was offset by the reduction of certain personnel costs at the propane operating partnerships.

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Depreciation and Amortization Expense. The increase in depreciation and amortization expense was primarily due to the depreciation and amortization of assets and amortizable intangibles added through acquisitions made after December 31, 2006.

Income Taxes

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

On May 18, 2006, the State of Texas enacted House Bill 3 which replaced the existing state franchise tax with a margin tax . In general, legal entities that conduct business in Texas are subject to the Texas margin tax, including previously non-taxable entities such as limited partnerships and limited liability partnerships. The tax is assessed on Texas sourced taxable margin which is defined as the lesser of (i) 70% of total revenue or (ii) total revenue less (a) cost of goods sold or (b) compensation and benefits. Although the bill states that the margin tax is not an income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers both revenues and expenses. Therefore, we have accounted for Texas margin tax as income tax expense in the period subsequent to the law s effective date of January 1, 2007. For the four months ended December 31, 2007, we recognized current state income tax expense related to the Texas margin tax of $3.9 million. There is no comparable state tax expense for the period ended December 31, 2006.

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

	Four Months Ended December 31, 2007	2006
Current provision:		
Federal	$ 2,990	$ 4,797
State	5,705	557
Total	8,695	5,354
Deferred provision (benefit):		
Federal	1,482	(1,972)
State	612	(262)
Total	2,094	(2,234)
Total tax provision	$ 10,789	$ 3,120
Effective tax rate	3.96%	1.91%

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

	Four Months Ended December 31, 2007	2006
Federal statutory tax rate	35.00%	35.00%
State income tax rate net of federal benefit	1.82%	3.48%
Earnings not subject to tax at the Partnership level	(32.86)%	(36.57)%
Effective tax rate	3.96%	1.91%

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Liquidity and Capital Resources

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

Future capital requirements of our business generally are expected to consist of:

- maintenance capital expenditures for the intrastate and interstate operations, which include capital expenditures made to connect additional wells to our natural gas systems in order to maintain or increase throughput on existing assets, for which we expect to expend approximately $70.0 million in the next calendar year and capital expenditures to extend the useful lives of our propane assets in order to sustain our operations, including vehicle replacements on our propane vehicle fleet, for which we expect to expend approximately $35.0 million in the next calendar year;

- growth capital expenditures, mainly for constructing new pipelines, processing plants, treating plants and compression for the midstream and intrastate transportation and storage segment for which we expect to expend approximately $950.0 million in the next calendar year. We also expect to spend approximately $790.0 million in our interstate segment for constructing new pipelines and pipeline expansion and approximately $30.0 million for customer propane tanks in the next calendar year; and

- acquisition capital expenditures including acquisition of new pipeline systems and propane operations.

We believe that cash generated from the operations of our businesses will be sufficient to meet anticipated maintenance capital expenditures. We generally fund our capital requirements by cash flows from operating activities and, to the extent that our future capital requirements exceed cash flows from operating activities, from the following sources:

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

- growth capital expenditures may be financed by the proceeds of borrowings under credit facilities, long-term debt, the issuance of additional common units or a combination thereof; and

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

The assets used in our natural gas operations, including pipelines, gathering systems and related facilities, are generally long-lived assets and do not require significant maintenance capital expenditures other than those expenditures necessary to maintain the service capacity of our existing assets. The assets utilized in our propane operations do not typically require lengthy manufacturing process time or complicated, high technology components. Accordingly, we do not have any significant financial commitments for maintenance capital expenditures in our businesses. From time to time we experience increases in pipe costs due to a number of reasons, including but not limited to, replacing pipe caused by delays from mills, limited selection of mills capable of producing large diameter pipe timely, higher steel prices and other factors beyond our control. However, we include these factors into our anticipated growth capital expenditures for each calendar year.

We manage our exposure to increased pipe costs by purchasing steel and reserving mill space, as projects are approved, in advance of construction. However, there is no assurance that we will not be impacted by increased pipe costs and limited mill space.

We engage in natural gas storage transactions in which we seek to find and profit from pricing differences that occur over time. Natural gas is typically purchased and held in storage during the summer months and sold during the winter months. Although we intend to fund natural gas purchases with cash generated from operations, from time to time we may need to finance the purchase of natural gas to be held in storage with borrowings from our current credit facilities. We intend to repay these borrowings with cash generated from operations when the gas is sold.

Cash Flows

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

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Operating Activities. Cash provided by operating activities during the four months ended December 31, 2007, was $245.7 million as compared to cash provided by operating activities of $420.9 million for the four months ended December 31, 2006. The net cash provided by operations for the four months ended December 31, 2007 consisted of net income of $261.8 million, non-cash charges of $70.9 million, principally depreciation and amortization, unit-based compensation expense, and gain on disposal of assets and a decrease in cash from changes in operating assets and liabilities of $87.0 million. Various components of operating assets and liabilities changed significantly from the prior period due to factors such as the change in value of price risk management assets and liabilities, variance in the timing of accounts receivable collections, payments on accounts payable, and the timing of the purchase and sale of inventories related to the propane and intrastate transportation and storage operations.

Investing Activities. Cash used in investing activities during the four months ended December 31, 2007 of $995.9 million was comprised primarily of cash paid for acquisitions of $337.1 million and $604.3 million invested for growth capital expenditures, including changes in accruals of $5.6 million. Total growth capital expenditures consists of $422.9 million for our intrastate operations and $167.1 million for our interstate operations, and $14.3 million for our propane operations. We also incurred $49.0 million in maintenance expenditures needed to sustain operations of which $21.4 million related to intrastate operations, $12.9 million related to interstate operations, and $14.7 million to propane operations.

Financing Activities. Cash provided by financing activities was $738.0 million for the four months ended December 31, 2007. We received $234.9 million in net proceeds from an equity offering (see Note 12 to our condensed consolidated financial statements). Proceeds from the equity offering and funds from the ETP Credit Facility were used to repay the $310.0 million ETP Term Loan Facility related to the Canyon acquisition (discussed below). We had a net increase in our debt level of $666.4 million primarily under the ETP Credit Facility (including the swingline loan option) to partially repay the ETP Term Loan Facility, to fund our growth capital expenditures and for general partnership purposes. During the four months ended December 31, 2007, we paid distributions of $176.0 million to our partners related to the fourth quarter of our fiscal year 2007.

Financing and Sources of Liquidity

During fiscal year 2006, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register a $1.0 billion aggregate offering price of our common units that may be offered for sale by us from time to time. In December 2007, we filed a Registration Statement on Form S-3 with the Securities and Exchange Commission to register an unspecified quantity of common units and an unspecified dollar amount of debt securities, in each case that may be offered for sale by us from time to time.

On December 18, 2007, the Partnership sold in a public offering 5 million common units representing limited partner interests at $48.81 per common unit. ETP used the offering proceeds of $234.9 million, net of issuance costs, to repay a portion of the outstanding debt under the ETP Term Loan Facility (discussed below). The remaining balance on the ETP Term Loan Facility was repaid with borrowings from the ETP Credit Facility. The offering closed on December 18, 2007. ETP also granted the underwriters a 30-day option to purchase up to an aggregate of 750,000 additional common units to cover over-allotments, if any. The underwriters exercised their option in full and ETP issued 750,000 additional common units at $48.81 per common unit on January 8, 2008. The proceeds of $35.2 million, net of offering costs, were used to repay borrowings from the ETP Credit Facility.

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Description of Indebtedness

Our indebtedness as of December 31, 2007 consists of $750.0 million in principal amount of 5.95% Senior Notes due 2015, $400.0 million in principal amount of 5.65% Senior Notes due 2012, $400.0 million in principal amount of 6.125% Senior Notes due 2017 and $400.0 million in principal amount of 6.625% Senior Notes due 2036 (collectively, the ETP Senior Notes) and a revolving credit facility that allows for borrowings of up to $2.0 billion (expandable to $3.0 billion) available through June 20, 2012 (the ETP Credit Facility). We also currently maintain separate credit facilities for Transwestern and HOLP. The terms of our indebtedness and that of our Operating Partnerships are described in more detail in our Annual Report on Form 10-K for fiscal 2007 filed with the Securities and Exchange Commission on October 30, 2007.

ETP Term Loan Facility

On December 18, 2007, we used proceeds received from an equity offering (see Note 12 to our condensed consolidated financial statements) and funds from the ETP Credit Facility to fully repay the ETP Term Loan Facility, a $310.0 million, 364-day term loan credit facility we executed on October 5, 2007 primarily to finance the Canyon acquisition. The ETP Term Loan Facility was a single draw term loan with an applicable Eurodollar rate plus 0.600% per annum based on our current rating by the rating agencies or at Base Rate for designated period.

ETP Credit Facility

On July 20, 2007, we entered into a credit agreement providing for the ETP Credit Facility, a $2.0 billion revolving 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. The aggregate amount of swingline loans in any borrowing shall not be subject to a minimum amount or increment. The indebtedness under the ETP Credit Facility is prepayable at any time at the Partnership s option without penalty. The commitment fee payable on the unused portion of the ETP Credit Facility varies based on our credit rating (0.11% based on our current rating) with a maximum fee of 0.125%.

As of December 31, 2007, there was a balance of $1.6 billion in revolving credit loans (including $273.9 million in swingline loans) and $61.3 million in letters of credit. The weighted average interest rate on the total amount outstanding at December 31, 2007, was 5.746%. The total amount available under the ETP Credit Facility, as of December 31, 2007, which is reduced by any amounts outstanding under the Swingline loan and letters of credit, was $311.7 million. 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.

ETP 364-Day Credit Facility

On February 5, 2008, ETP entered into a credit agreement providing for a $500.0 million, 364-day term loan credit facility (the 364-Day Credit Facility). Borrowings under the 364-Day Credit Facility will be used for general corporate purposes. The 364-Day Credit Facility is a single draw term loan with an applicable Eurodollar rate plus 1.000% per annum based on our current rating by the rating agencies or at Base Rate for designated period. We expect to draw the entire amount on or about February 12, 2008. The indebtedness under the 364-Day Credit Facility is unsecured and is not guaranteed by any of our or ETP s subsidiaries. Borrowings under the 364-Day Credit Facility, upon proper notice to the administrative agent, may be prepaid in whole or in part without premium or penalty. The loan agreement related to the 364-Day Credit Facility requires any proceeds received from debt or equity issuance, assets sales, or accordion increases be used to make a mandatory prepayment on the outstanding loan balance. This loan agreement contains covenants that are similar to the covenants of the ETP Credit Facility.

HOLP Credit Facility

A $75.0 million Senior Revolving Facility (the HOLP Facility) is available to HOLP through June 30, 2011 which may be expanded to $150.0 million. The HOLP Facility has a swingline loan option with a maximum borrowing of $10.0 million at a prime rate. Amounts borrowed under the HOLP Facility bear interest at a rate based on either a Eurodollar rate or a prime rate. The commitment fee payable on the unused portion of the facility varies based on the Leverage Ratio, as defined in the HOLP Facility credit agreement, with a maximum fee of 0.50%. The agreement includes provisions that may require contingent prepayments in the event of dispositions, loss of assets, merger or change of control. All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts of HOLP, and the capital stock of HOLP s subsidiaries secure the HOLP Facility. As of December 31, 2007, there was $15.0 million outstanding on the revolving credit loans. A Letter of Credit issuance is available to HOLP for up to 30 days prior to the maturity date of the HOLP Facility. There were outstanding Letters of Credit of $1.0 million at December 31, 2007. The weighted average interest rate on the total amount outstanding at December 31, 2007, was 5.97%. The sum of the loans made under the HOLP Facility plus the Letter of Credit Exposure and the aggregate amount of all swingline loans cannot exceed the $75.0 million maximum amount of the HOLP Facility. The amount available at December 31, 2007 was $59.0 million.

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HOLP Senior Secured Notes

All receivables, contracts, equipment, inventory, general intangibles, cash concentration accounts, and the capital stock of HOLP and its subsidiaries secure the HOLP Senior Secured, Medium Term, and Senior Secured Promissory Notes (collectively, the HOLP Notes). In addition to the stated interest rate for the HOLP Notes, we are required to pay an additional 1% per annum on the outstanding balance of the HOLP Notes at such time as the HOLP Notes are not rated investment grade status or higher. As of December 31, 2007 the HOLP Notes were rated investment grade or better thereby alleviating the requirement that we pay the additional 1% interest.

Cash Distributions

We use cash provided by operating and financing activities from the Operating Partnerships to provide distributions to our Unitholders as well as to our General Partner in respect of its 2% general partner interest and its incentive distribution rights. Under the Partnership Agreement, we will distribute to our partners within 45 days after the end of each fiscal quarter, an amount equal to all of our Available Cash for such quarter. Available Cash generally means, with respect to any quarter of the Partnership, all cash on hand at the end of such quarter less the amount of cash reserves established by the General Partner in its reasonable discretion that is necessary or appropriate to provide for future cash requirements.

On October 15, 2007, we paid a quarterly distribution of $0.825 per Common Unit ($3.30 per unit on an annualized basis) to Unitholders of record at the close of business on October 5, 2007. Our General Partner s incentive distributions rights entitle it to receive incentive distributions to the extent that quarterly distributions to our Unitholders exceed $0.275 per unit (which amount represents $1.10 per unit on an annualized basis).

In connection with the previously announced change in the Partnership s year end from August 31 to December 31, the Partnership amended its partnership agreement to provide that, in lieu of making a cash distribution for the three-month period ended November 30, 2007, the Partnership will make a cash distribution for the four-month period ended December 31, 2007. Based on this change in timing, on January 18, 2008 ETP s Board of Directors approved the payment of a four-month distribution to ETP Unitholders of $1.125 per unit, representing a distribution of $0.84375 per unit for the three-month period and $0.28125 per unit for the additional month. This represents an increase of $0.075 per unit on an annualized basis. The four-month distribution will be paid on February 14, 2008 to Unitholders of record as of the close of business on February 1, 2008.

After this distribution payment, the Partnership will continue to make quarterly distributions on a three-month basis as we have done in the past with the next scheduled quarterly distribution payments occurring in mid May, mid August, and mid November.

New Accounting Standards

See Note 3 to our condensed consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The information contained in Item 3 updates, and should be read in conjunction with, information set forth in Part II, Item 7A in our Annual Report on Form 10-K for the year ended August 31, 2007, in addition to the interim unaudited condensed consolidated financial statements, accompanying notes and management s discussion and analysis of financial condition and results of operations presented in Items 1 and 2 of this Transition Report on Form 10-Q. Our quantitative and qualitative disclosures about market risk are consistent with those discussed in our Annual Report on Form 10-K.

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Commodity-related Derivatives

Our commodity-related price risk management assets and liabilities as of December 31, 2007 were as follows:

	Commodity	Notional Volume MMBTU	Maturity	Fair Value
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

Sensitivity Analysis

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

	Notional Volume MMBTU	Fair Value	Effect of Hypothetical 10% Change
Non-Trading Derivatives			
Basis Swaps IFERC/NYMEX	(8,522,500)	$ (4,029)	$ 690
Swing Swaps IFERC	(4,640,000)	(1,515)	166
Fixed Swaps/Futures	(40,107,500)	41,143	29,841
Forward Physical Contracts	(17,847,140)	(1,063)	941
Options	(670,000)	(161)	75
Propane Forwards/Swaps (in Gallons)	9,282,000	3,319	1,478
Trading Derivatives			
Basic Swaps IFERC/NYMEX	(18,362,500)	2,298	815

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

Interest Rate Risk

We are exposed to market risk for increases in interest rates, primarily as a result of our variable rate debt and, in particular, our bank credit facilities. To the extent interest rates increase, our interest expense for our revolving credit

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facilities will also increase. At December 31, 2007, we had $1.64 billion of variable rate debt outstanding and a pay fixed receive float interest rate swap with a notional amount of $125.0 million that is not designated as a hedge. Changes in fair value of the swap are recorded in other income on the consolidated statement of operations. A hypothetical change of 100 basis points in the underlying interest rate and a corresponding parallel shift in the LIBOR yield curve would have a net effect of $14.9 million in interest expense and other income, in the aggregate, on an annual basis.

We are also subject to interest rate risk on our fixed rate debt if interest rates decrease. To manage this risk, we may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt. For further information, see Note 14 to our condensed consolidated financial statements.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Control over Financial Reporting

We closed the acquisition of Transwestern on December 1, 2006 and have begun the integration of the internal control structure of Transwestern into our processes and controls. We converted Transwestern s accounting system to our accounting system effective November 1, 2007 and are continuing to implement our internal control structure over Transwestern s operations.

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

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For information regarding legal proceedings, see our Form 10-K for the year ended August 31, 2007 and Note 13 - Regulatory Matters, Commitments, Contingencies and Environmental Liabilities of the Notes to Condensed Consolidated Financial Statements of Energy Transfer Partners, L.P. and Subsidiaries included in this Form 10-Q for the four-month period ended December 31, 2007.

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ITEM 1A. RISK FACTORS

In addition to the risks described in our Annual Report on Form 10-K for the year ended August 31, 2007, we are subject to the following additional risks:

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 dates 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 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 Hub and the Katy Hub near Houston, Texas. 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 negotiated rates, 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 rates would be limited to sales of natural gas to retail customers (such as utilities and other end users) and sales from our own production, and any other sales of natural gas by us would be required to be made at prices that would be subject to FERC approval. Also 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 Exchange Act by attempting to manipulate natural gas prices in the Houston Ship Channel. It is alleged that such manipulation was attempted during the period from late September through early December 2005 to allow us to benefit financially from our commodities derivatives positions.

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. 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. 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. In its lawsuit, the CFTC is seeking civil penalties of $130 thousand per violation, or three times the profit gained from each violation, and other ancillary relief. The CFTC has not specified the number of alleged violations or the amount of alleged profit related to the matters specified in its complaint. On October 15, 2007, ETP filed a motion to dismiss in the United State District Court for the Northern District of Texas on the basis that the CFTC has not stated a valid cause of action under the Commodity Exchange Act.

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 and CFTC hold substantial enforcement authority. At this time, we are unable to predict the final outcome of these matters.

In addition to the FERC and CFTC legal actions, 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 and CFTC 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, 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. One of the producers also seeks to intervene in the FERC

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proceeding, alleging that it is entitled to a FERC-ordered refund of $5.9 million, plus interest and costs. This producer has also filed a complaint at FERC against us and ETE requesting an agency hearing and claiming that we and ETE violated the NGA by failing to make sales for resale at negotiated rates; intentionally engaged in market manipulation; knowingly submitted misleading information to Platts; and caused damages to the producer group in the amount of $5.9 million. This producer has requested refunds and other remedies. On December 20, 2007, the FERC denied this producer s request to intervene in the FERC proceeding and on February 6, 2008 the FERC dismissed this producer s complaint.

In addition, 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 Commodity Exchange Act (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 also violated the CEA because we knowingly aided and abetted violations of the CEA. This action alleges that this 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 plaintiff and all other members of the putative class who purchased and/or sold natural gas futures and options contracts on NYMEX during the class period. The class action complaint consolidated two class actions which were pending against us. Following the consolidation order, the plaintiffs who had filed these two earlier class actions filed the consolidated complaint. They have requested certification of their suit as a class action, 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.

We are expensing the legal fees, consultants fees and related 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 negotiated settlement basis or otherwise, will exceed the amount of our existing 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.

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

Not applicable.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

Not applicable.

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

None.

ITEM 5. OTHER INFORMATION

None.

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ITEM 6. EXHIBITS

(a) Exhibits

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

	Exhibit Number	Description
(1)	3.1	Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(8)	3.1.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(13)	3.1.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(16)	3.1.4	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(18)	3.1.5	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(18)	3.1.6	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(27)	3.1.7	Amendment No. 7 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(28)	3.1.8	Amendment No. 8 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P. (formerly named Heritage Propane Partners, L.P.)
(39)	3.1.9	Amendment No. 9 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(37)	3.1.10	Amendment No. 10 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(48)	3.1.11	Amended and Restated Amendment No. 11 to Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners, L.P.
(1)	3.2	Agreement of Limited Partnership of Heritage Operating, L.P.
(10)	3.2.1	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(16)	3.2.2	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.2.3	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Heritage Operating, L.P.
(18)	3.3	Amended Certificate of Limited Partnership of Energy Transfer Partners, L.P.
(15)	3.4	Amended Certificate of Limited Partnership of Heritage Operating, L.P.
(45)	3.5	Third Amended and Restated Agreement of Limited Partnership of Energy Transfer Partners GP, L.P.
(45)	3.6	Third Amended and Restated Limited Liability Agreement of Energy Transfer Partners, L.L.C.
(17)	4.1	Registration Rights Agreement for Limited Partner Interests of Heritage Propane Partners, L.P.

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	Exhibit Number	Description
(18)	4.2	Unitholder Rights Agreement dated January 20, 2004 among Heritage Propane Partners, L.P., Heritage Holdings, Inc., TAAP LP and La Grange Energy, L.P.
(22)	4.3	Indenture dated January 18, 2005 among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(23)	4.4	First Supplemental Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(29)	4.5	Second Supplemental Indenture dated as of February 24, 2005 to Indenture dated as of January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(24)	4.7	Registration Rights Agreement, dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(30)	4.8	Joinder to Registration Rights Agreement, dated February 24, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors and Wachovia Bank, National Association as trustee.
(31)	4.9	Third Supplemental Indenture dated as of July 29, 2005 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(32)	4.10	Registration Rights Agreement, dated July 29, 2005, among Energy Transfer Partners, L.P., the subsidiary guarantors named therein and the initial purchasers thereto.
(33)	4.11	Form of Senior Indenture of Energy Transfer Partners, L.P.
(33)	4.12	Form of Subordinated Indenture of Energy Transfer Partners, L.P.
(43)	4.13	Fourth Supplemental Indenture dated as of June 29, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(34)	4.14	Fifth Supplemental Indenture dated as of October 23, 2006 to Indenture dated January 18, 2005, among Energy Transfer Partners, L.P, the subsidiary guarantors named therein and Wachovia Bank, National Association, as trustee.
(37)	4.15	Registration Rights Agreement, dated November 1, 2006, between Energy Transfer Partners, L.P. and Energy Transfer Equity, L.P.
(46)	10.1	Amended and Restated Credit Agreement, dated July 20, 2007, among Energy Transfer Partners, L.P., the borrower and Wachovia Bank, National Association, as administrative agent, LC issuer and swingline lender, Bank of America, N.A., as syndication agent, BNP Paribas, JPMorgan Chase Bank, N.A. and the Royal Bank of Scotland PLC, as co-documentation agents and Citibank, N.A., Credit Suisse, Cayman Islands Branch, Deutsche Bank Securities, Inc., Morgan Stanley Bank, Suntrust Bank and UBS Securities, LLC as senior managing agents, and other lenders party hereto.
(1)	10.2	Form of Note Purchase Agreement (June 25, 1996).
(2)	10.2.1	Amendment of Note Purchase Agreement (June 25, 1996) dated as of July 25, 1996.
(3)	10.2.2	Amendment of Note Purchase Agreement (June 25, 1996) dated as of March 11, 1997.
(5)	10.2.3	Amendment of Note Purchase Agreement (June 25, 1996) dated as of October 15, 1998.
(6)	10.2.4	Second Amendment Agreement dated September 1, 1999 to June 25, 1996 Note Purchase Agreement.
(7)	10.2.5	Third Amendment Agreement dated May 31, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.
(8)	10.2.6	Fourth Amendment Agreement dated August 10, 2000 to June 25, 1996 Note Purchase Agreement and November 19, 1997 Note Purchase Agreement.

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		Exhibit Number	Description
(11)		10.2.7	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(15)	**	10.6.3	Second Amended and Restated Restricted Unit Plan dated as of February 4, 2002.
(49)		10.6.5	Form of Grant Agreement.
(45)	**	10.6.6	Amended and Restated 2004 Unit Plan.
(4)		10.16	Note Purchase Agreement dated as of November 19, 1997.
(5)		10.16.1	Amendment dated October 15, 1998 to November 19, 1997 Note Purchase Agreement.
(6)		10.16.2	Second Amendment Agreement dated September 1, 1999 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(7)		10.16.3	Third Amendment Agreement dated May 31, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(8)		10.16.4	Fourth Amendment Agreement dated August 10, 2000 to November 19, 1997 Note Purchase Agreement and June 25, 1996 Note Purchase Agreement.
(11)		10.16.5	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(19)		10.16.6	Sixth Amendment Agreement dated as of November 18, 2003 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(8)		10.19	Note Purchase Agreement dated as of August 10, 2000.
(11)		10.19.1	Fifth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(12)		10.19.2	First Supplemental Note Purchase Agreement dated as of May 24, 2001 to the August 10, 2000 Note Purchase Agreement.
(19)		10.19.3	Sixth Amendment Agreement dated as of December 28, 2000 to June 25, 1996 Note Purchase Agreement, November 19, 1997 Note Purchase Agreement and August 10, 2000 Note Purchase Agreement.
(25)		10.42	Purchase and Sale Agreement, dated January 26, 2005, among HPL Storage, LP and AEP Energy Services Gas Holding Company II, L.L.C., as Sellers and La Grange Acquisition, L.P., as Buyer.
(26)		10.43	Cushion Gas Litigation Agreement, dated January 26, 2005, by and among AEP Energy Services Gas Holding Company II, L.L.C. and HPL Storage LP, as Sellers, and La Grange Acquisition, L.P., as Buyer, and AEP Asset Holdings LP, AEP Leaseco LP, Houston Pipe Line Company, LP and HPL Resources Company LP, as Companies.
(43)	**	10.45	Summary of Director Compensation.
(40)		10.51	Purchase and Sale Agreement, dated as of September 14, 2006, among Energy Transfer Partners, L.P. and EFS-PA, LLC (a/k/a GE Energy Financial Services), CDPQ Investments (U.S.), Inc., Lake Bluff, Inc., Merrill Lynch Ventures, L.P. and Kings Road Holdings I, LLC.
(41)		10.52	Redemption Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and CCE Holdings, LLC.
(42)		10.53	Letter Agreement, dated September 14, 2006, between Energy Transfer Partners, L.P. and Southern Union Company.

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	Exhibit Number	Description
(46)	10.54	Fourth Amended and Restated Credit Agreement dated as of August 31, 2006 between and among Heritage Operating L.P., as the Borrower, and the Banks now or hereafter signatory parties hereto, as lenders Banks and Bank of Oklahoma, National Association as administrative agent and joint lead arranger for the Banks, JPMorgan Chase Bank, N.A., as syndication agent for the Banks, and J.P. Morgan Securities Inc., as joint lead arranger for the Banks.
(45)	10.55	Note Purchase Agreement, dated as of November 17, 2004, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(45)	10.55.1	Amendment No. 1 to the Note Purchase Agreement, dated as of April 18, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(45)	10.56	Note Purchase Agreement, dated as of May 24, 2007, by and among Transwestern Pipeline Company, LLC and the Purchasers parties thereto.
(47)	21.1	List of Subsidiaries.
(*)	31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
(*)	32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
(*)	32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

* Filed herewith.

** Denotes a management contract or compensatory plan or arrangement.

(1) Incorporated by reference to the same numbered Exhibit to Registrant s Registration Statement of Form S-1, File No. 333-04018, filed with the Commission on June 21, 1996.

(2) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended November 30, 1996.

(3) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended February 28, 1997.

(4) Incorporated by reference to the same numbered Exhibit to Registrant s Form 10-Q for the quarter ended May 31, 1998.

(5) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1998.

(6) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 1999.

(7) Incorporated by reference to the Exhibit 10.16.3 to the Registrant s Form 10-Q for the quarter ended May 31, 2000.

(8) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated August 23, 2000.

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(10) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2000.
(11) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2001.
(12) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2001.
(13) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2001.
(14) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended November 30, 2001.
(15) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2002.
(16) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2002.
(17) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K dated February 4, 2002.
(18) Incorporated by reference as the same numbered exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(19) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 29, 2004.
(20) Incorporated by reference to Annex A of the Registrant s Schedule 14A Proxy Statement filed May 18, 2004.
(21) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed November 1, 2004.
(22) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed January 19, 2005.
(23) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed January 19, 2005.
(24) Incorporated by reference to Exhibit 4.3 to the Registrant s Form 8-K filed January 19, 2005.
(25) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed February 1, 2005.
(26) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed February 1, 2005.
(27) Incorporated by reference to Exhibit 3.1.7 to the Registrant s Form 8-K filed March 16, 2005.
(28) Incorporated by reference to Exhibit 3.1.8 to the Registrant s Form 8-K filed February 9, 2006.
(29) Incorporated by reference to Exhibit 10.45 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(30) Incorporated by reference to Exhibit 10.39.1 to the Registrant s Form 10-Q for the quarter ended February 28, 2005.
(31) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed August 2, 2005.
(32) Incorporated by reference to Exhibit 4.2 to the Registrant s Form 8-K filed August 2, 2005.

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(33) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K/A for the year ended August 31, 2005.
(34) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed December 16, 2005.
(35) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed December 16, 2005.
(36) Incorporated by reference to Exhibit 4.1 to the Registrant s Form 8-K filed October 25, 2006.
(37) Incorporated by reference to Exhibit 3.1.10 to the Registrant s Form 8-K filed November 3, 2006.
(38) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2006.
(39) Incorporated by reference to Exhibit 3.1.9 to the Registrant s Form 8-K filed May 3, 2006.
(40) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed September 18, 2006.
(41) Incorporated by reference to Exhibit 10.2 to the Registrant s Form 8-K filed September 18, 2006.
(42) Incorporated by reference to Exhibit 10.3 to the Registrant s Form 8-K filed September 18, 2006.
(43) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-K for the year ended August 31, 2006.
(44) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended February 28, 2007.
(45) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 10-Q for the quarter ended May 31, 2007.
(46) Incorporated by reference to the same numbered Exhibit to the Registrant s Form 8-K filed on July 23, 2007.
(47) Incorporated by reference to Exhibit 10.1 to the Registrant s Form 8-K filed on October 9, 2007.
(48) Incorporated by reference to Exhibit 3.1.11 to the Registrant s Form 8-K filed on January 18, 2008.
(49) Incorporated by reference to Exhibit 10.6.5 to the Registrant s Form 10-Q for the quarter ended November 30, 2007.

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SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

ENERGY TRANSFER PARTNERS, L.P.

By: Energy Transfer Partners GP, L.P.,

its General Partner

By: Energy Transfer Partners, L.L.C., its General Partner

Date: February 11, 2008

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

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