ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 09, 2005

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

(Mark One)

þ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2005

OR

o **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: 1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

311 Rouser Road	
Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	(Zip code)

Registrant s telephone number, including area code: **(412) 262-2830**

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 þ No o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).

Yes þ No o

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
INDEX TO QUARTERLY REPORT
ON FORM 10-Q

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(in thousands)
(Unaudited)

	June 30, 2005	December 31, 2004
ASSETS		
Current assets:		
Cash and cash equivalents	$ 13,342	$ 18,214
Accounts receivable-affiliates	3,488	1,496
Accounts receivable	29,565	13,769
Prepaid expenses	972	1,056
Total current assets	47,367	34,535
Property, plant and equipment, net	327,288	175,259
Goodwill	62,305	2,305
Other assets	7,362	4,686
	$444,322	$216,785
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 63	$ 2,303
Accrued liabilities	11,355	3,144
Current portion of hedge liability	11,972	1,959
Accrued producer liabilities	23,364	10,996
Accounts payable	3,853	2,341
Distribution payable	9,492	6,467
Total current liabilities	60,099	27,210
Long-term hedge liability, less current portion	9,684	722
Long-term debt, less current portion	168,103	52,149
Commitments and contingencies		
Partners capital:		
Limited partners interests	221,754	135,761
General partner s interest	3,954	2,261

Accumulated other comprehensive loss	(19,272)	(1,318)
Total partners capital	206,436	136,704
	$444,322	$216,785

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(in thousands, except per unit data)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Revenues:				
Natural gas and liquids	$79,700	$	$122,034	$
Transportation and compression affiliates	5,352	4,454	10,199	8,647
Transportation and compression third parties	23	15	38	32
Interest income and other	124	80	205	116
Total revenues and other income	85,199	4,549	132,476	8,795
Costs and expenses:				
Natural gas and liquids	66,582		102,041	
Plant operating	3,293		4,497	
Transportation and compression	622	538	1,298	1,145
General and administrative	3,368	368	5,479	836
Compensation reimbursement affiliates	440	215	953	328
Depreciation and amortization	3,128	593	5,057	1,111
Interest	4,177	63	5,312	126
Total costs and expenses	81,610	1,777	124,637	3,546
Net income	$ 3,589	$2,772	$ 7,839	$5,249
Allocation of net income:				
Limited partners interest	$ 1,573	$2,359	$ 4,403	$4,481
General partner s interest	2,016	413	3,436	768
Net income	$ 3,589	$2,772	$ 7,839	$5,249
Net income per limited partner unit basic and diluted	$ 0.20	$ 0.47	$ 0.58	$ 0.95
Weighted average limited partner units outstanding:				
Basic	7,938	5,039	7,573	4,697
Diluted	7,990	5,040	7,609	4,697

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF PARTNERS CAPITAL
FOR THE SIX MONTHS ENDED JUNE 30, 2005
(in thousands, except unit data)
(Unaudited)

	Number of Limited Partner Units					Accumulated Other	Total
	Common	Subordinated	Common	Subordinated	General Partner	Comprehensive Loss	Partners Capital
Balance at January 1, 2005	5,563,659	1,641,026	$135,759	$ 2	$ 2,261	$ (1,318)	$136,704
Conversion of subordinated units	1,641,026	(1,641,026)	2	(2)			
Issuance of common units in public offering	2,300,000		91,661				91,661
Issuance of common units under long-term incentive plan	331		14				14
Capital contributions					1,930		1,930
Unissued common units under long-term incentive plan			2,829				2,829
Distributions to partners			(5,404)		(1,500)		(6,904)
Distribution payable			(7,319)		(2,173)		(9,492)
Distribution equivalent rights paid on unissued units under long-term incentive plan			(191)				(191)
Other comprehensive loss						(17,954)	(17,954)
Net income			4,403		3,436		7,839
Balance at June 30, 2005	9,505,016		$221,754	$	$ 3,954	$ (19,272)	$206,436

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 7,839	$ 5,249
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	5,057	1,111
Non-cash gain on derivative value	(701)	
Non-cash compensation under long-term incentive plan	2,158	37
Amortization of deferred finance costs	1,475	76
Change in operating assets and liabilities, net of effects of acquisitions:		
Increase in accounts receivable and prepaid expenses	(9,973)	(452)
Increase in accounts payable and accrued liabilities	18,816	247
(Increase) decrease in accounts receivable affiliates	(1,992)	1,416
Net cash provided by operating activities	22,679	7,684
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisitions	(195,622)	
Capital expenditures	(22,883)	(2,521)
Other	177	(2,004)
Net cash used in investing activities	(218,328)	(4,525)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	256,000	
Repayments under credit facility	(142,250)	
Distributions paid to partners	(13,371)	(6,192)
General partner capital contributions	1,930	512
Net proceeds from issuance of limited partner units	91,661	25,188
Other	(3,193)	(365)
Net cash provided by financing activities	190,777	19,143
Net change in cash and cash equivalents	(4,872)	22,302
Cash and cash equivalents, beginning of period	18,214	15,078
Cash and cash equivalents, end of period	$ 13,342	$37,380

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
JUNE 30, 2005
(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a Delaware limited partnership formed in May 1999 to acquire, own and operate natural gas gathering systems previously owned by Atlas America, Inc. (Atlas or Atlas America) and its affiliates. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by the Partnership s operating subsidiary, Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership). Atlas Pipeline Partners GP, LLC, a wholly-owned subsidiary of Atlas (the General Partner), owns, through its general partner interests in the Partnership and the Operating Partnership, a 2% general partner interest in the consolidated pipeline operations. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests in the Partnership. Through its general partner interest, the General Partner effectively manages and controls both the Partnership and the Operating Partnership.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2004 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management s opinion, all adjustments necessary for a fair presentation of the Partnership s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2004. The results of operations for the three and six month periods ended June 30, 2005 may not necessarily be indicative of the results of operations for the full year ending December 31, 2005.

Certain previously reported amounts have been reclassified to conform to the current presentation.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In addition to matters discussed further within this note, a more thorough discussion of the Partnership s significant accounting policies is included in its audited consolidated financial statements and notes thereto in the Partnership s annual report on Form 10-K for the year ended December 31, 2004.

Net Income Per Unit

Basic net income per limited partner unit is computed by dividing net income, after deducting the general partner s interest, by the weighted average number of limited partner units outstanding for the period. The general partner s interest in net income is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 4). Diluted net income per limited partner unit is calculated by dividing net income applicable to limited partners by the sum of the weighted-average number of limited partner units outstanding and the dilutive effect of phantom unit awards, as calculated by the treasury stock method. Phantom units consist of common units issuable under the terms of the Partnership s Long-Term Incentive Plan (see Note 11).

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Net Income Per Unit (Continued)

The following table sets forth the reconciliation of the weighted average number of limited partner units used to compute basic net income per limited partner unit to those used to compute diluted net income per limited partner unit for the three and six months ended June 30, 2005 and 2004 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Weighted average number of limited partner units basic	7,938	5,039	7,573	4,697
Add effect of dilutive unit incentive awards	52	1	36	
Weighted average number of limited partner units diluted	7,990	5,040	7,609	4,697

Receivables

In evaluating its accounts receivable for impairment, the Partnership performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by the Partnership s review of its customers credit information. The Partnership extends credit on an unsecured basis to many of its energy customers. At June 30, 2005 and December 31, 2004, the Partnership recorded no allowance for accounts receivable impairment.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income, are referred to as other comprehensive income (loss) and for the Partnership include only changes in the fair value of unsettled hedge contracts.

The following table sets forth the calculation of the Partnership s comprehensive income (loss):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Net income	$ 3,589	$2,772	$ 7,839	$5,249
Other comprehensive loss:				
Unrealized loss on hedging contracts	(10,947)		(19,885)	
Add: reclassification adjustment for losses realized in net income	1,262		1,931	
	(9,685)		(17,954)	
Comprehensive (loss) income	$ (6,096)	$2,772	$(10,115)	$5,249

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

Revenue Recognition

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs and oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership s records and management estimates of the related transportation and compression fees which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at June 30, 2005 and December 31, 2004 of $30.6 million and $15.3 million, respectively, included in accounts receivable and accounts receivable-affiliates within the consolidated balance sheets.

Goodwill

At June 30, 2005 and December 31, 2004, the Partnership had $62.3 million and $2.3 million, respectively, of goodwill which was recognized in connection with consummated acquisitions (see Note 7). The Partnership tests its goodwill for impairment at each year end by comparing fair values to its carrying values. The evaluation of impairment under Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets, requires the use of projections, estimates and assumptions as to the future performance of the Partnership s operations, including anticipated future revenues, expected future operating costs and the discount factor used. Actual results could differ from projections, resulting in revisions to the Partnership s assumptions and, if required, recognition of an impairment loss. The Partnership s test of goodwill at December 31, 2004 resulted in no impairment, and no impairment indicators have been noted as of June 30, 2005. The Partnership will continue to evaluate its goodwill at least annually and when impairment indicators arise, will reflect the impairment of goodwill, if any, within the consolidated statements of income in the period in which the impairment is indicated.

New Accounting Standards

In May 2005, the Financial Accounting Standards Board (FASB) issued SFAS No. 154, Accounting Changes and Error Corrections (SFAS No. 154). SFAS No. 154 requires retrospective application to prior periods financial statements for changes in accounting principle. It also requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings for that period rather than being reported in an income statement. The statement will be effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The impact of SFAS No. 154 will depend on the nature and extent of any voluntary accounting changes and corrections of errors after the effective date, but management does not currently expect SFAS No. 154 to have a material impact on the Partnership s financial position or results of operations.

In March 2005, the FASB issued FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations (FIN 47), which will result in (a) more consistent recognition of liabilities relating to asset retirement obligations, (b) more information about expected future cash outflows associated with those obligations, and (c) more information about investments in long-lived assets because additional asset retirement costs will be recognized as part of the carrying amounts of the assets. FIN 47 clarifies that the term conditional asset retirement obligation as used in SFAS No. 143, Accounting for Asset Retirement Obligations, refers to a legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (Continued)

New Accounting Standards (Continued)

settlement. Uncertainty about the timing and (or) method of settlement of a conditional asset retirement obligation should be factored into the measurement of the liability when sufficient information exists. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. Retrospective application of interim financial information is permitted but is not required. Early adoption of this interpretation is encouraged. As FIN 47 was recently issued, the Partnership has not yet determined whether the interpretation will have a significant adverse effect on its financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (R) (revised 2004) Share-Based Payment, which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation. SFAS No. 123 (R) supersedes Accounting Principals Board Opinion (APB) No. 25, Accounting for Stock Issued to Employees, and amends SFAS No. 95, Statement of Cash Flows. Generally, the approach to accounting in Statement 123 (R) requires all share-based payments to employees, including grants of employee stock options, to be recognized in the financial statements based on their fair values. Currently, the Partnership follows APB No. 25 and its interpretations, which allow for valuation of share-based payments to employees at their intrinsic values. Under this methodology, the Partnership recognizes compensation expense for phantom units granted at their fair value at the date of grant and compensation expense for options granted only if the current market price of the underlying units exceed the exercise price. SFAS No. 123 (R) is effective for the Partnership beginning January 1, 2006. The Partnership does not expect SFAS No. 123 (R) to have a material impact on its consolidated financial statements.

NOTE 3 EQUITY OFFERINGS

On June 2, 2005, the Partnership sold 2.3 million common units in a public offering for total gross proceeds of $96.5 million. The units were issued under the Partnership s previously filed Form S-3 shelf registration statement. The sale of the units resulted in net proceeds of approximately $91.7 million, after underwriting commissions and other transaction costs. The Partnership primarily utilized the net proceeds from the sale to repay a portion of the amounts due under its credit facility. In connection with this offering, the General Partner contributed $1.9 million to the Partnership in order to maintain its 2.0% general partner interest. At June 30, 2005, Atlas ownership interest in the Partnership was 18.9%, including its 2.0% general partner interest.

On July 20, 2004, the Partnership sold 2.1 million common units in a public offering for total gross proceeds of $73.0 million. The units were issued under the Partnership s previously filed Form S-3 shelf registration statement. The sale of the units resulted in net proceeds of approximately $67.5 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale primarily to repay a portion of the amounts due under its credit facility. In connection with this offering, the General Partner contributed $1.5 million to the Partnership in order to maintain its 2.0% general partner interest.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 3 EQUITY OFFERINGS (Continued)

On April 14, 2004, the Partnership sold 0.8 million common units in a public offering for total gross proceeds of $25.4 million. The units were issued under the Partnership s previously filed Form S-3 shelf registration statement. The sale of the units resulted in net proceeds of approximately $25.2 million, after underwriting commissions and other transaction costs. The Partnership utilized the net proceeds from the sale primarily to repay a portion of the amounts due under its credit facility. In connection with this offering, the General Partner contributed $0.5 million to the Partnership in order to maintain its 2.0% general partner interest.

NOTE 4 DISTRIBUTIONS

The Partnership will generally make quarterly cash distributions of substantially all of its available cash, generally defined as cash on hand at the end of the quarter less cash reserves established by the General Partner, at its discretion, to provide for future operating costs, potential acquisitions and future distributions, among other items. Pursuant to the partnership agreement, the General Partner receives incremental incentive cash distributions when cash distributions exceed certain target thresholds. Distributions paid by the Partnership for the period from January 1, 2004 through June 30, 2005 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution per Limited Partner Unit	Total Cash Distribution to Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 6, 2004	December 31, 2003	$0.625	$2,722	$ 351
May 7, 2004	March 31, 2004	$0.630	$2,743	$ 374
August 6, 2004	June 30, 2004	$0.630	$3,216	$ 438
November 5, 2004	September 30, 2004	$0.690	$4,971	$ 1,060
February 11, 2005	December 31, 2004	$0.720	$5,187	$ 1,280
May 13, 2005	March 31, 2005	$0.750	$5,404	$ 1,500

On June 13, 2005, the Partnership declared a cash distribution of $0.77 per unit on its outstanding limited partner units, representing the cash distribution for the quarter ended June 30, 2005. The $9.5 million distribution, including $2.2 million to the general partner, will be paid on August 5, 2005 to unitholders of record at the close of business on June 30, 2005.

At December 31, 2004, the Partnership had 1,641,026 subordinated units outstanding, all of which were held by the general partner. In January 2005, these subordinated units were converted to common units as the Partnership met the tests under the terms of the partnership agreement. While the general partner s rights as the holder of the subordinated units are no longer subordinated to the rights of the common unitholders, these units have not yet been registered with the Securities and Exchange Commission and, therefore, their resale in the public market is subject to restrictions under the Securities Act.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment consist of the following (in thousands):

	June 30, 2005	December 31, 2004	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$323,535	$168,932	15 - 40
Rights of way	16,121	14,128	20 - 40
Buildings	3,397	3,215	40
Furniture and equipment	648	517	3 - 7
Other	470	307	3 - 10
	344,171	187,099	
Less accumulated depreciation	(16,883)	(11,840)	
	$327,288	$175,259	

In April 2005, the Partnership completed the acquisition of ETC Oklahoma Pipeline, Ltd. for approximately $194.9 million (see Note 7). Due to its recent date of acquisition, the purchase price allocation is based upon estimated values determined by the Partnership, which are subject to adjustment and could change significantly as the Partnership continues to evaluate this allocation. At June 30, 2005, the purchase price allocated to property, plant and equipment for this acquisition by the Partnership was included within the pipelines, processing and compression facilities category within the above table.

NOTE 6 OTHER ASSETS

Other assets consist of the following (in thousands):

	June 30, 2005	December 31, 2004
Deferred finance costs, net of accumulated amortization of $856 and $506 at June 30, 2005 and December 31, 2004, respectively	$4,997	$ 3,316
Security deposits	1,728	1,356
Other	637	14
	$7,362	$ 4,686

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 9). In June 2005, the Partnership recognized $1.0 million of accelerated amortization of deferred financing costs associated with the retirement of the term portion of its $270 million credit facility.

NOTE 7 -ACQUISITIONS

Spectrum

On July 16, 2004, the Partnership acquired Spectrum Field Services, Inc. (Spectrum), for approximately $143.1 million, including transaction costs and the payment of taxes due as a result of the transaction. Spectrum s principal assets included 1,900 miles of natural gas pipelines and a natural gas processing facility in Velma, Oklahoma. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, Business Combinations. The following table presents the purchase price

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 7 ACQUISITIONS (Continued)

Spectrum (Continued)

allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed, based on their fair values at the date of acquisition (in thousands):

Cash and cash equivalents	$ 803
Accounts receivable	18,505
Prepaid expenses	649
Property, plant and equipment	140,936
Other long-term assets	1,054
Total assets acquired	161,947
Accounts payable and accrued liabilities	(17,153)
Hedging liabilities	(1,519)
Long-term debt	(164)
Total liabilities assumed	(18,836)
Net assets acquired	$143,111

The results of the acquisition were included with the Partnership s consolidated financial statements from its date of acquisition.

Elk City

On April 14, 2005, the Partnership acquired all of the outstanding equity interests in ETC Oklahoma Pipeline, Ltd. (Elk City), a Texas limited partnership, for $194.9 million, including related transaction costs. Elk City s principal assets included 318 miles of natural gas pipelines located in the Anadarko Basin in western Oklahoma, a natural gas processing facility in Elk City, Oklahoma, with total capacity of 130 million cubic feet of gas per day (mmcf/d) and a gas treatment facility in Prentiss, Oklahoma, with a total capacity of 100 mmcf/d. The purchase price is subject to post-closing adjustments based upon, among other things, gas imbalances, certain prepaid expenses and capital expenditures, and title defects, if any. The acquisition was accounted for using the purchase method of accounting under SFAS No. 141, Business Combinations. The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed, based on their fair values at the date of acquisition (in thousands):

Accounts receivable	$ 4,577
Other assets	497
Property, plant and equipment	133,637
Goodwill	60,000
Total assets acquired	198,711
Accounts payable and accrued liabilities	(3,770)

Total liabilities assumed	(3,770)
Net assets acquired	$ 194,941

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 7 ACQUISITIONS (Continued)

Elk City (Continued)

Due to its recent date of acquisition, the purchase price allocation for Elk City is based upon estimated values determined by the Partnership. These estimates are subject to adjustment and could change significantly as the Partnership continues to evaluate this allocation. The Partnership recognized goodwill in connection with this acquisition as a result of Elk City s significant cash flow and its strategic industry position. The results of the acquisition were included within the Partnership s consolidated financial statements from its date of acquisition.

The following data presents pro forma revenues, net income and basic and diluted net income per limited partner unit for the Partnership as if the acquisitions discussed above and the equity offerings in July 2004 and June 2005, from which the net proceeds were utilized to repay debt borrowed to finance the acquisitions (see Note 3), had occurred on January 1, 2004. The Partnership has prepared these pro forma financial results for comparative purposes only. These pro forma financial results may not be indicative of the results that would have occurred if the Partnership had completed these acquisitions at the beginning of the periods shown below or the results that will be attained in the future (in thousands except per unit amounts):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Total revenues and other income	$85,199	$75,151	$173,208	$138,518
Net income	$ 4,651	$ 4,560	$ 7,555	$ 6,494
Net income per limited partner unit, basic and diluted	$ 0.33	$ 0.82	$ 0.54	$ 1.21

NOTE 8 DERIVATIVE INSTRUMENTS

The Partnership enters into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133. The Partnership entered into these instruments to hedge the forecasted natural gas, NGL and condensate sales against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGL and condensate is sold. Under these swap agreements, the Partnership receives a fixed price and pays a floating price based on certain indices for the relevant contract period. The options fix the price for the Partnership within the puts purchased and calls sold.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 8 DERIVATIVE INSTRUMENTS (Continued)

The Partnership formally documents all relationships between hedging instruments and the items being hedged, including the Partnership s risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. The Partnership assesses, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of hedged items. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of correlation between the hedging instrument and the underlying commodity, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by the Partnership through utilization of market data, will be recognized immediately within the Partnership s consolidated statements of income.

Derivatives are recorded on the balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, the effective portion of changes in fair value are recognized in partners capital as other comprehensive income (loss) and reclassified to natural gas and liquids revenue within the consolidated statements of income as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, changes in fair value are recognized within the consolidated statements of income as they occur. At June 30, 2005, the Partnership reflected a net hedging liability on its balance sheet of $19.9 million. Of the $19.3 million net loss in other comprehensive income (loss) at June 30, 2005, $10.3 million of losses will be reclassified to the consolidated statements of income over the next twelve month period as these contracts expire, and $9.0 million will be reclassified in later periods if the fair values of the instruments remain at current market values. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded in natural gas and liquids revenue within the consolidated statements of income while the hedge contract is open and may increase or decrease until settlement of the contract. The Partnership recognized a loss of $1.3 million and $1.9 million related to these hedging instruments during the three and six months ended June 30, 2005, respectively. These losses are included within natural gas and liquids revenue on the Partnership s consolidated statements of income. There were no hedging instruments outstanding during the three and six months ended June 30, 2004.

As of June 30, 2005, the Partnership had the following NGLs, natural gas, crude oil and plant reduction volumes hedged:

Natural Gas Basis Swaps

Production Period Ended June 30,	Volumes (MMBTU)[1]	Average Fixed Price (per MMBTU)	Fair Value Liability[3] (in thousands)
2006	1,260,000	$ (0.537)	$ (83)
2007	1,140,000	(0.530)	(67)
2008	780,000	(0.541)	(55)
			$ (205)

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 8 DERIVATIVE INSTRUMENTS (Continued)

Plant Volume Reduction Basis Swaps

Production Period Ended June 30,	Volumes (MMBTU)[1]	Average Fixed Price (per MMBTU)	Fair Value Asset[3] (in thousands)
2006	1,800,000	$ (0.478)	$ 12
2007	900,000	(0.495)	21
			$ 33

Natural Gas Liquids Fixed Price Swaps

Production Period Ended June 30,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[2] (in thousands)
2006	37,104,000	$0.662	$ (9,235)
2007	24,570,000	0.686	(5,821)
2008	9,954,000	0.698	(2,079)
			$(17,135)

Natural Gas Fixed Price Swaps

Production Period Ended June 30,	Volumes (MMBTU)[1]	Average Fixed Price (per MMBTU)	Fair Value Liability[3] (in thousands)
2006	1,200,000	$ 6.594	$ (1,419)
2007	1,140,000	7.131	(889)
2008	780,000	7.260	(235)
			$ (2,543)

Crude Oil Fixed Price Swaps

Production Period Ended June 30,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability[3] (in thousands)
2006	54,450	$51.558	$ (403)
2007	74,400	53.638	(358)
2008	55,200	55.875	(91)

			$ (852)

Plant Volume Reduction Fixed Price Swaps

Production Period Ended June 30,	Volumes (MMBTU)[1]	Average Fixed Price (per MMBTU)	Fair Value Asset[3] (in thousands)
2006	1,650,000	$ 7.205	$ 995
2007	900,000	7.255	548
			$ 1,543

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 8 DERIVATIVE INSTRUMENTS (Continued)

Crude Oil Options

Production Period Ended June 30,	Option Type	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)
2006	Puts purchased	30,000	$ 30.00	$
2006	Calls sold	30,000	34.25	(721)
				$ (721)
			Total net liability	$(19,880)

(1) MMBTU represents million British Thermal Units.

(2) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas and light crude prices.

(3) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

NOTE 9 LONG-TERM DEBT

Total debt consists of the following (in thousands):

	June 30, 2005	December 31, 2004

Credit Facility:		
Revolving credit facility	$ 168,000	$ 10,000
Term loan		44,250
Other debt	166	202
	168,166	54,452
Less current maturities	(63)	(2,303)
	$ 168,103	$ 52,149

On April 14, 2005, the Partnership entered into a new $270.0 million credit facility (the Credit Facility) with a syndicate of banks, which replaced its existing $135.0 million facility. The facility was comprised of a five-year $225.0 million revolving line of credit and a five-year $45.0 million term loan. The term loan portion of the Credit Facility was repaid and retired from the net proceeds of the June 2005 equity offering (see Note 3). The revolving portion of the Credit Facility bears interest, at the Partnership s option, at either (i) Adjusted LIBOR plus the applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding Credit Facility borrowings at June 30, 2005 was 6.07%. Up to $10.0 million of the credit facility may be utilized for letters of credit, of which $8.2 million is outstanding at June 30, 2005 and is not reflected as borrowings on the Partnership s consolidated balance sheet. Borrowings under the Credit Facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, and by the guaranty of each of the Partnership s subsidiaries.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 9 LONG-TERM DEBT (Continued)

The Credit Facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in the Partnership s subsidiaries. The Credit Facility also contains covenants requiring the Partnership to maintain, on a rolling four-quarter basis, a maximum total debt to EBITDA ratio (each as defined in the credit agreement) of 5.5 to 1, reducing to 4.5 to 1 on September 30, 2005 and thereafter; and an interest coverage ratio (as defined in the credit agreement) of at least 3.0 to 1. The Partnership is in compliance with these covenants as of June 30, 2005. Based upon the definitions set forth within the credit agreement, the Partnership s ratio of total debt to EBITDA was 4.1 to 1 and the interest coverage ratio was 4.5 to 1 at June 30, 2005.

NOTE 10 COMMITMENTS AND CONTINGENCIES

The Partnership is a party to various routine legal proceedings arising out of the ordinary course of its business. Management believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on the Partnership s financial condition or results of operations.

On March 9, 2004, the Oklahoma Tax Commission (OTC) filed a petition against Spectrum alleging that Spectrum underpaid gross production taxes beginning in June 2000. The OTC is seeking a settlement of $5.0 million plus interest and penalties. The Partnership plans on defending itself vigorously. In addition, under the terms of the Spectrum purchase agreement, $14.0 million has been placed in escrow to cover the costs of any adverse settlement resulting from the petition and other indemnification obligations of the purchase agreement.

NOTE 11 LONG-TERM INCENTIVE PLAN

The Partnership has a Long-Term Incentive Plan (LTIP), in which officers, employees and non-employee managing board members of the General Partner and employees of the General Partner s affiliates and consultants are eligible to participate. The Plan is administered by a committee (the Committee) appointed by the General Partner s managing board of directors. The Committee may make awards of either phantom units or unit options for an aggregate of 435,000 common units. Only phantom units have been granted under the LTIP through June 30, 2005.

A phantom unit entitles a grantee to receive a common unit upon vesting of the phantom unit or, at the discretion of the Committee, cash equivalent to the fair market value of a common unit. In addition, the Committee may grant a participant a distribution equivalent right (DER), which is the right to receive cash per phantom unit in an amount equal to, and at the same time as, the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. A unit option entitles the grantee to purchase the Partnership s common units at an exercise price determined by the Committee at its discretion. The Committee also has discretion to determine how the exercise price may be paid by the participant. Except for phantom units awarded to non-employee managing board members of the General Partner, the Committee will determine the vesting period for phantom units and the exercise period for options. Through June 30, 2005, phantom units granted under the LTIP generally had vesting periods of four years. The vesting period may also include the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards will automatically vest upon a change of control, as defined

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 11 LONG-TERM INCENTIVE PLAN (Continued)

in the LTIP. Of the units outstanding under the LTIP at June 30, 2005, 31,214 units will vest within the following twelve months.

The Partnership accounts for equity awards under the LTIP in accordance with the provisions of APB No. 25 and its interpretations, which allows for valuation of these awards at their intrinsic values. Under this methodology, the Partnership recognizes compensation expense for phantom units granted at their fair value at the date of grant. For options granted, the Partnership recognizes compensation expense at the date of the grant only if the current market price of the underlying units exceeds the exercise price.

The following table sets forth the LTIP phantom unit activity for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Outstanding, beginning of period	125,201	1,692	58,752	
Granted[1]		56,906	67,338	58,598
Performance factor adjusted[2]	140,211		140,211	
Matured	(226)		(436)	
Forfeited	(340)	(846)	(1,019)	(846)
Outstanding, end of period	264,846	57,752	264,846	57,752
Non-cash compensation expense recognized (in thousands)	$ 1,709	$ 70	$ 2,158	$ 72

(1) The weighted average price for phantom unit awards on the date of grant was $0 and $37.19 for awards granted for the three months ended June 30, 2005 and 2004, respectively, and $48.58 and $37.15 for awards granted for the six months ended June 30, 2005 and 2004, respectively.

(2) Consists of adjustments to

performance-based awards to reflect actual performance.

NOTE 12 RELATED PARTY TRANSACTIONS

On June 30, 2005, Resource America, Inc. (RAI) distributed its 10.7 million shares of Atlas to its shareholders. In connection with this distribution of Atlas common stock to its shareholders, RAI and Atlas entered into various agreements, including shared services and a tax matters agreement, which govern the ongoing relationship between the two companies. The Partnership is dependent upon the resources and services provided by Atlas, and through these agreements, RAI and its affiliates. Accounts receivable/payable affiliates represents the net balance due from/to Atlas and RAI and its affiliates for natural gas transported through the gathering systems, net of reimbursements for Partnership costs and expenses paid by Atlas and RAI and its affiliates. Substantially all Partnership revenue in Appalachia is from Atlas and RAI and its affiliates.

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of RAI and/or the Affiliates. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions.

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 12 RELATED PARTY TRANSACTIONS (Continued)

The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to their executive officers, based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by the Affiliates based on the number of their employees who devote substantially all of their time to activities on the Partnership s behalf. The Partnership reimburses the Affiliates at cost for direct costs incurred by them on its behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. The Partnership reimbursed the General Partner and its affiliates \$0.4 million and \$0.2 million for the three months ended June 30, 2005 and 2004, respectively, and \$1.0 million and \$0.3 million for the six months ended June 30, 2005 and 2004, respectively, for compensation and benefits related to their executive officers. For the three months ended June 30, 2005 and 2004, direct reimbursements were \$7.6 million and \$2.2 million, respectively, and \$11.9 million and \$4.5 million for the six months ended June 30, 2005 and 2004, respectively, including certain costs that have been capitalized by the Partnership. The General Partner believes that the method utilized in allocating costs to the Partnership is reasonable.

Under an agreement with the Affiliates, Atlas must construct up to 2,500 feet of sales lines from its existing wells in the Appalachian region to a point of connection to the Partnership s gathering systems. The Partnership must, at its own cost, extend its system to connect to any such lines within 1,000 feet of its gathering systems. With respect to wells to be drilled by Atlas that will be more than 3,500 feet from the Partnership s gathering systems, the Partnership has various options to connect those wells to its gathering systems at its own cost.

NOTE 13 OPERATING SEGMENT INFORMATION

The Partnership has two business segments: natural gas gathering and transmission located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York and western Pennsylvania, and gathering and processing located in the Mid-Continent area (Mid-Continent) of southern Oklahoma and northern Texas. Appalachia revenues are principally based on contractual arrangements with Atlas and its affiliates. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs to purchasers at the tailgate of the processing plants. These operating segments reflect the way the Partnership manages its operations.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
JUNE 30, 2005
(Unaudited)

NOTE 13 OPERATING SEGMENT INFORMATION (Continued)

The following tables summarize the Partnership s operating segment data for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Mid-Continent:				
Revenues				
Natural gas and liquids	$79,700	$	$122,034	$
Interest income and other	31		17	
Total revenues and other income	79,731		122,051	
Costs and expenses				
Natural gas and liquids	66,582		102,041	
Plant operating	3,293		4,497	
General and administrative	2,298		3,049	
Depreciation and amortization	2,503		3,858	
Total costs and expenses	74,676		113,445	
Segment profit	$ 5,055	$	$ 8,606	$
Appalachia:				
Revenues				
Transportation and compression affiliates	$ 5,352	$4,454	$ 10,199	$8,647
Transportation and compression third parties	23	15	38	32
Interest income and other	93	80	188	116
Total revenues and other income	5,468	4,549	10,425	8,795
Costs and expenses				
Transportation and compression	622	538	1,298	1,145
General and administrative	741	291	1,609	582
Depreciation and amortization	625	593	1,199	1,111
Total costs and expenses	1,988	1,422	4,106	2,838
Segment profit	$ 3,480	$3,127	$ 6,319	$5,957

Reconciliation of segment profit to net income:				
Segment profit				
Mid-Continent	$ 5,055	$	$ 8,606	$
Appalachia	3,480	3,127	6,319	5,957
Total segment profit	8,535	3,127	14,925	5,957
General and administrative	(769)	(292)	(1,774)	(582)
Interest	(4,177)	(63)	(5,312)	(126)
Net income	$ 3,589	$2,772	$ 7,839	$5,249

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)
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NOTE 13 OPERATING SEGMENT INFORMATION (Continued)

	June 30, 2005	December 31, 2004
Balance sheet		
Total assets:		
Mid-Continent	$395,319	$157,675
Appalachia	30,503	39,400
Corporate other	18,500	19,710
	$444,322	$216,785
Goodwill:		
Mid-Continent	$ 60,000	$
Appalachia	2,305	2,305
	$ 62,305	$ 2,305

The following tables summarizes the Partnership s total revenues by product or service for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Natural gas and liquids:				
Natural gas	$44,067	$	$ 67,724	$
NGLs	31,549		48,933	
Condensate	1,494		2,221	
Other (1)	2,590		3,156	
Total	$79,700	$	$122,034	$
Transportation and Compression:				
Affiliates	$ 5,352	$4,454	$ 10,199	$8,647
Third parties	23	15	38	32
Total	$ 5,375	$4,469	$ 10,237	$8,679

(1) Includes treatment, processing, and other revenue

associated with
the products
noted.

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

Forward-Looking Statements

When used in this Form 10-Q, the words believes , anticipates , expects , and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 1, under the caption Risk Factors , in our annual report on Form 10-K for 2004. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

The following discussion provides information to assist in understanding our financial condition and results of operations. This discussion should be read in conjunction with our consolidated financial statements and notes thereto appearing elsewhere in this report.

General

Our principal business objective is to generate cash for distribution to our unitholders. Our business is conducted in the midstream segment of the natural gas industry and we are active in the Appalachian and Mid-Continent areas of the United States, specifically, Pennsylvania, Ohio, New York, Oklahoma and Texas.

In Appalachia, we gather natural gas through our pipeline system from more than 4,850 wells for delivery to a variety of customers on major intra- and/or interstate pipeline systems and a limited number of direct end-users. This transported gas is primarily controlled by Atlas America, Inc., the parent company of our general partner.

Our Mid-Continent operations began in July 2004 upon our acquisition of Spectrum Field Services, Inc. in Velma, Oklahoma. We refer to the Spectrum assets as our Velma operations. During the six months ended June 30, 2005 we gathered 69.4 million cubic feet (mmcf) of gas per day from approximately 150 producers in our Velma operations. This gas is then transported to our processing facilities where the natural gas liquids, or NGLs, along with various impurities are removed. The remaining pipeline quality gas is then delivered into a major intra- and/or interstate pipeline system where it is sold at market prices. The NGLs are similarly delivered into a separate major intrastate liquids product pipeline system where they are also sold for a price determined by the value of the actual components of that liquid stream, such as ethane, butane, propane and natural gasoline.

Our Elk City operations began in April 2005 upon our acquisition of ETC Oklahoma Pipeline, Ltd., in Elk City, Oklahoma. As of June 30, 2005 we gathered 244.1 mmcf of gas per day from approximately 130 producers in our Elk City operations. Our Elk City operations transport, process and sell natural gas similarly to our Velma operations.

Spectrum Acquisition

On July 16, 2004, we acquired our Velma gathering system for approximately $143.1 million, including the payment of income taxes due as a result of the transaction. This acquisition significantly increased our size and diversified the natural gas supply basins in which we operate and the natural gas midstream services we provide to our customers.

Elk City Acquisition

On April 14, 2005, we acquired Elk City from affiliates of Energy Transfer Partners, L.P. (NYSE: ETP) for $194.9 million in cash, including related transaction costs. The purchase price is subject to post-closing adjustments based upon, among other things, gas imbalances, certain prepaid expenses and capital expenditures, and title defects, if any. We financed the Elk City acquisition, including approximately $2.8 million of transaction costs, by borrowing $45.0 million of the term loan portion and $204.5 million of the revolving loan portion of our new $270.0 million senior secured term loan and revolving credit facility administered by Wachovia Bank.

Fee Arrangements

In Appalachia, substantially all of the gas we transport is for Atlas America under percentage of proceeds, or POP, contracts (as described below) where we earn a fee equal to a percentage, generally 16%, of the selling price of the gas subject, in most cases, to a minimum of $0.35 or $0.40 per thousand cubic feet, or mcf. Since our inception in January 2000, our transportation fee has always exceeded this minimum. The balance of the Appalachian gas we transport is for third party operators generally under fixed fee contracts.

Our revenues in the Mid-Continent area are determined primarily by the fees we earn from the following types of arrangements:

Fee-Based Contracts. Under these contracts, we receive a set fee for gathering and processing raw natural gas. Our revenue is a function of the volume of gas that we gather and process and is not directly dependent on the value of that gas.

Percent of Proceeds Contracts. Under these contracts, we retain a negotiated percentage of the residue natural gas and NGLs resulting from our gathering and processing operations, with the remainder being remitted to the producer. In this situation, we and the producer are directly dependent on the volume of the commodity and its value; we own a percentage of that commodity and are directly subject to its ultimate market value.

Approximately 72% of the natural gas volumes and approximately 76% of the natural gas revenues of our Velma operations are derived from POP contracts. The percentage of the proceeds that we retain is negotiated and can vary greatly depending on a variety of factors and circumstances.

Keep Whole Contracts. As a result of our newly acquired Elk City gathering systems, we have keep whole contracts. Keep whole contracts require the processor to bear the economic risk (called the processing margin risk) that the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that the processor paid for the unprocessed natural gas. However, since gas received into our Elk City system is generally low in liquids content and meets downstream pipeline specifications without being processed, the gas can be bypassed around our Elk City processing plant and delivered directly into downstream pipelines during periods of margin risk.

As a result of our POP and keep whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas and NGLs. We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. The number of active oil and gas rigs has increased in the past year, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during 2005. However, energy market uncertainty could negatively impact North American drilling activity in the short term. Lower drilling levels over a sustained period would have a negative effect on natural gas volumes gathered and processed.

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We closely monitor the risks associated with these commodity price changes on our future operations and, where appropriate, use various commodity instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. We do not realize the full impact of commodity price changes because some of our sales volumes were previously hedged at prices different than actual market prices.

Results of Operations

In the six months ended June 30, 2005, our principal revenues came from the sale of residue gas and NGLs. In the six months ended June 30, 2004, our principal revenues came from the operation of our Appalachia pipeline system. Variables which affect our revenues are:

- the volumes of natural gas gathered, transported and processed by us which, in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas they produce, and the demand for natural gas and NGLs; and
- the transportation and processing fees paid to us which, in turn, depend upon the price of the natural gas and NGLs we transport and process, which itself is a function of the relevant supply and demand in the mid-continent, mid-Atlantic and northeastern areas of the United States.

The following table illustrates selected volumetric information related to our operating segments for the periods indicated:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Mid-Continent				
Elk City				
Natural Gas				
Gross natural gas gathered mcf/day	244,088		244,088	
Gross natural gas processed mcf/day	118,000		118,000	
Gross residue natural gas mcf/day	108,000		108,000	
NGLs				
Gross NGL sales barrels/day	5,537		5,537	
Condensate				
Gross condensate sales barrels/day	119		119	
Velma				
Natural Gas				
Gross natural gas gathered mcf/day	73,810		69,408	
Gross natural gas processed mcf/day	68,326		65,671	
Gross residue natural gas mcf/day	56,893		53,456	
Natural gas gross margin (in thousands) (1) (3)	$ 2,378	$	$ 4,897	$
NGLs				
Gross NGL sales barrels/day	7,149		6,778	
NGL gross margin (in thousands) (2) (3)	$ 4,797	$	$ 8,760	$
Condensate				
Gross condensate sales barrels/day	278		256	
Condensate sales (3)	$ 1,259	$	$ 1,961	$

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	2004	2005	2004
Appalachia				
Throughout mcf/day	54,694	52,442	53,539	51,940
Average transportation rate per mcf	$ 1.08	$ 0.94	$ 1.06	$ 0.92
Total transportation and compression revenue (in thousands)	$ 5,375	$ 4,469	$10,237	$ 8,679

(1) Gross margin calculated as natural gas revenue less natural gas costs.

(2) Gross margin calculated as NGL revenue less NGL costs.

(3) Natural gas and NGL gross margins and condensate sales do not include effects of hedging gains or losses, which are reflected in our natural gas and liquids revenue on our consolidated statements of income.

Second Quarter 2005 Compared with Second Quarter 2004

Revenues

Natural gas and liquids revenues of $79.7 million for the three months ended June 30, 2005 were associated with our acquisitions of Spectrum in July 2004 and Elk City in April 2005. For the second quarter of 2005, the Velma system connected 25 new wells to its gas gathering assets. Overall, 153 new wells were connected to the system for the twelve months ended June 30, 2005. Gross natural gas processed averaged 68.3 million cubic feet, or mmcf, per day on the Velma system for the second quarter of 2005, an increase of 8% from the first quarter of 2005. On the Elk City system, nine new wells were connected to its gas gathering pipelines from April 14, 2005, its date of acquisition, to June 30, 2005. Gross natural gas processed on the Elk City system averaged 118.0 mmcf per day from its date of acquisition to June 30, 2005.

Appalachian transportation and compression revenues increased to $5.4 million for the three months ended June 30, 2005 from $4.5 million for the second quarter of 2004. This $0.9 million increase was primarily due to an increase in the average transportation rate earned and an increase in the volumes of natural gas we transported. Our average transportation rate was $1.08 per mcf for the second quarter of 2005 as compared to $0.94 per mcf for the prior year second quarter, an increase of $0.14 per mcf. Our average daily throughput volumes were 54.7 mmcf for the second quarter of 2005 as compared with 52.4 mmcf for the second quarter of 2004, and increase of 2.3 mmcf. The increase in the average daily throughput volume was principally due to new wells connected to our gathering system. For the twelve months ended June 30, 2005, we connected 357 new wells to the Appalachian gathering system as compared with 310 new wells for the comparable prior year period.

Costs and Expenses

Natural gas and liquids cost of goods sold of $66.6 million and plant operating expenses of $3.3 million for the three months ended June 30, 2005 were associated with our acquisitions of Spectrum in July 2004 and Elk City in April 2005. Appalachian transportation and compression expenses increased slightly to $0.6 million for the second quarter of 2005. This increase was primarily due to higher maintenance expense as a result of additional pipelines and compressors added to accommodate new wells.

General and administrative expenses, including amounts reimbursed to affiliates, increased $3.2 million to $3.8 million for the second quarter of 2005 compared with $0.6 million for the prior year second quarter. This increase was mainly due to a $1.7 million increase in non-cash compensation expense related to phantom units issued under our long-term incentive plan and $1.3 million of expenses associated with the acquisitions previously described. Depreciation and amortization increased to $3.1 million for the second quarter 2005 compared with $0.6 million for the second quarter of 2004 due principally to the increased asset base associated with the acquisitions.

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Interest expense increased to $4.2 million for the three months ended June 30, 2005 as compared with $0.1 million for the second quarter of 2004. This $4.1 million increase was primarily due to interest associated with borrowings under the credit facility to finance the acquired assets and $1.0 million of accelerated amortization related to previously deferred financing costs. This accelerated amortization was associated with the retirement of the term portion of our $270 million credit facility in April 2005.

Six Months Ended June 30, 2005 Compared with Six Months Ended June 30, 2004

Revenues

Natural gas and liquids revenues of $122.0 million for the six months ended June 30, 2005 were associated with the acquired assets previously described. On the Velma system, gross natural gas processed averaged 65.7 mmcf per day for the first half of 2005. Gross natural gas processed on the Elk City system averaged 118.0 mmcf per day from its date of acquisition to June 30, 2005.

Appalachian transportation and compression revenues increased to $10.2 million for the first half of June 30, 2005 from $8.7 million for the prior year period. This $1.5 million increase was primarily due to an increase in the average transportation rate earned and an increase in the volumes of natural gas we transported. Our average transportation rate was $1.06 per mcf for the first six months of 2005 as compared to $0.92 per mcf for the prior year first six months, an increase of $0.14 per mcf. Our average daily throughput volumes were 53.5 mmcf for the six months ended June 30, 2005 as compared with 51.9 mmcf for the first half of 2004, an increase of 1.6 mmcf. The increase in the average daily throughput volume was principally due to new wells connected to our gathering system.

Costs and Expenses

Natural gas and liquids cost of goods sold of $102.0 million and plant operating expenses of $4.5 million for the six months ended June 30, 2005 were associated with the acquired assets. Appalachian transportation and compression expenses increased slightly to $1.3 million for the first half of 2005. This increase was primarily due to higher maintenance expense as a result of additional pipelines and compressors added to accommodate new wells.

General and administrative expenses, including amounts reimbursed to affiliates, increased $5.1 million to $6.3 million for the first half of 2005 compared with $1.2 million for the prior year first half. This increase was mainly due to a $2.2 million increase in non-cash compensation expense related to phantom units issued under our long-term incentive plan and $2.0 million of expenses associated with the acquisitions previously described. Depreciation and amortization increased to $5.1 million for the first six months of 2005 compared with $1.1 million for the first six months of 2004 due principally to the increased asset base associated with the acquisitions.

Interest expense increased to $5.3 million for the first half of 2005 as compared with $0.1 million for the first half of 2004. This $5.2 million increase was primarily due to interest associated with borrowings under the credit facility to finance the acquired assets and $1.0 million of accelerated amortization related to deferred financing costs previously described.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our unitholders and general partner. In general, we expect to fund:

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cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;

expansion capital expenditures and working capital deficits through the retention of cash and additional borrowings; and

debt principal payments through additional borrowings as they become due or by the issuance of additional common units.

At June 30, 2005, we had $168.0 million of outstanding borrowings under our credit facility, with $48.8 million of available borrowing capacity. Our percentage of total debt to total capitalization, which is the sum of total debt and total partners capital, was 45% at June 30, 2005 compared with 28% at December 31, 2004. This increase was mainly due to additional borrowings to finance the acquisition of the Elk City assets for $194.9 million in April 2005. We also had a working capital deficit of $12.7 million at June 30, 2005 compared with working capital of $7.3 million at December 31, 2004. This decrease was primarily due to an increase in the current portion of our net hedge liability between periods and is reflected in the change in fair-market value of our derivative instruments based on the subsequent increases in the price of natural gas after we entered into the hedges. These price increases will be reflected in our consolidated statements of income when the contracts settle.

Cash Flows

Net cash provided by operating activities of $22.7 million for the six months ended June 30, 2005 increased $15.0 million from $7.7 million for the first half of 2004. The increase is derived principally from increases in net income of $2.6 million, depreciation and amortization of $3.9 million, non-cash compensation under the long-term incentive plan of $2.2 million, and a decrease in working capital of $5.7 million. The increases in net income and depreciation and amortization were principally due to the acquisitions of Spectrum in July 2004 and Elk City in April 2005. The decrease in working capital between periods is mainly due to the increase in the current portion of our net hedge liability as discussed above.

Net cash used in investing activities was $218.3 million for the six months ended June 30, 2005, an increase of $213.8 million from $4.5 million for the first six months of 2004. This increase was principally due to the acquisition of Elk City in April 2005 and a $20.4 million increase in capital expenditures. See further discussion of capital expenditures under Capital Requirements.

Net cash provided by financing activities was $190.8 million for the six months ended June 30, 2005, an increase of $171.7 million from $19.1 million for the first half of 2004. This increase was principally due to a $66.5 million increase in net proceeds received from sales of common units and $113.7 million of net borrowings under our credit facility, mainly to fund the acquisition of the Elk City assets. These increases were partially offset by an increase in cash distributions to partners of $7.2 million due primarily to an increase in limited partner units outstanding and the distribution amount per limited partner unit.

Capital Requirements

Our operations require continual investment to upgrade or enhance existing operations and to ensure compliance with safety, operational, and environmental regulations. The capital requirements for our operations consist primarily of:

maintenance capital expenditures to maintain equipment reliability and safety and to address environmental regulations; and

expansion capital expenditures to acquire complementary assets to grow our operations and to expand the capacity of our existing operations.

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The following table summarizes maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2005	**2004**	**2005**	**2004**
Maintenance capital expenditures	$ 473	$ 228	$ 865	$ 597
Expansion capital expenditures	16,333	1,108	22,018	1,924
Total	$16,806	$1,336	$22,883	$2,521

Expansion capital expenditures increased to $16.3 million and $22.0 million for the three and six months ended June 30, 2005, respectively, due principally to expansions of the Velma and Elk City gathering systems and processing facilities to accommodate new wells drilled in our service areas. In addition, expansion capital expenditures increased due to compressor upgrades and gathering system expansions in the Appalachian region. Maintenance capital expenditures for the three and six months ended June 30, 2005 increased slightly due to additional maintenance activity on the Velma and Elk City acquired assets compared with the prior year periods. As of June 30, 2005, we are committed to expend approximately $7.9 million on pipeline extensions, compressor station upgrades and processing facility upgrades. We anticipate that our expansion capital expenditures will increase for the remainder of 2005 as a result of an increase in the estimated number of well connections to our gathering systems.

Credit Facility

Total debt consists of the following (in thousands):

	June 30, 2005	**December 31, 2004**
Credit Facility:		
Revolving credit facility	$168,000	$ 10,000
Term loan		44,250
Other debt	166	202
	168,166	54,452
Less current maturities	(63)	(2,303)
	$168,103	$ 52,149

On April 14, 2005, we entered into a new $270.0 million credit facility with a syndicate of banks, which replaced our existing $135.0 million facility. The facility is comprised of a five-year $225.0 million revolving line of credit and a five-year $45.0 million term loan. The term loan portion of the credit facility was repaid and retired from the net proceeds of the June 2005 equity offering. The revolving portion of the credit facility bears interest, at our option, at either (i) Adjusted LIBOR plus an applicable margin, as defined, or (ii) the higher of the federal funds rate plus 0.5% or the Wachovia Bank prime rate (each plus the applicable margin). The weighted average interest rate on the outstanding credit facility borrowings at June 30, 2005 was 6.07%. Up to $10.0 million of the credit facility may be utilized for letters of credit, of which $8.2 million is outstanding at June 30, 2005 and is not reflected as borrowings on our consolidated balance sheet. Borrowings under the facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, and by the guaranty of each of our subsidiaries.

The credit facility contains customary covenants, including restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our

subsidiaries. The credit facility also contains covenants requiring us to maintain, on a rolling four-quarter basis, a maximum total debt to EBITDA ratio (each as defined in the credit agreement) of 5.5 to 1, reducing to 4.5 to 1 on September 30, 2005 and thereafter; and an interest coverage ratio (as defined in the credit agreement) of at least 3.0 to 1. We are in compliance with these covenants as of June 30, 2005. Based upon the definitions set forth within the credit agreement, our ratio of total debt to EBITDA was 4.1 to 1 and the interest coverage ratio was 4.5 to 1 at June 30, 2005.

Contractual Obligations and Commercial Commitments

The following tables summarize our contractual obligations and commercial commitments at June 30, 2005:

		Payments Due By Period			
Contractual cash obligations:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Long-term debt [1]	$168,166	$ 63	$103	$168,000	$
Capital lease obligations					
Operating leases	746	268	308	170	
Unconditional purchase obligations					
Other long-term obligations					
Total contractual cash obligations	$168,912	$331	$411	$168,170	$

(1) Not included in the table above are estimated interest payments calculated at the rates in effect at June 30, 2005, 2006 $10.3 million; 2007 $10.3 million; 2008 $10.4 million; 2009 $10.3 million; and 2010 $8.1 million.

The operating leases represent lease commitments for compressors, office space, and office equipment with varying expiration dates. These commitments are routine and were made in the normal course of our business.

		Amount of Commitment Expiration Per Period			
Other commercial commitments:	**Total**	**Less than 1 Year**	**1 3 Years**	**4 5 Years**	**After 5 Years**
Standby letters of credit	$ 8,167	$ 8,167	$	$	$

Guarantees					
Standby replacement commitments					
Other commercial commitments	7,866	7,866			
Total commercial commitments	$16,033	$16,033	$	$	$

Other commercial commitments relate to commitments to install new compressors and sales lines for new well hookups, and expenditures for pipeline extensions.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenues and expenses during the reporting period. Although we believe our

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estimates are reasonable, actual results could differ from those estimates. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2004, and there have been no material changes to these policies through June 30, 2005.

New Accounting Standards

See discussion of new accounting pronouncements in Note 2 within the accompanying consolidated financial statements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term market risk refers to the risk of loss arising from adverse changes in interest rates and oil and gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than trading.

All of our assets and liabilities are denominated in U.S. dollars and, as a result, we do not have exposure to currency exchange risks.

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on June 30, 2005. Only the potential impacts of hypothetical assumptions are analyzed. The analysis does not consider other possible effects that could impact our business.

Interest Rate Risk. At June 30, 2005, we had a $225.0 million revolving credit facility ($168.0 million outstanding) to fund the expansion of our existing gathering systems, acquire other natural gas gathering systems and fund working capital movements as needed. The weighted average interest rate for these borrowings was 6.07% at June 30, 2005. Holding all other variables constant, a 1% change in interest rates would change interest expense by $1.7 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of commodities rather than cash. For gathering services, we receive fees for commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. Based on our current portfolio of gas supply contracts, we have long condensate, NGL and natural gas positions. A 10% increase in the average price of NGLs, natural gas and crude oil we process and sell would result in an increase to our 2005 annual income of approximately $2.5 million. A 10% decrease in the average price of NGLs, natural gas and crude oil we process and sell would result in a decrease to our 2005 annual income of $2.3 million.

We enter into certain financial swap and option instruments that are classified as cash flow hedges in accordance with SFAS No. 133. We enter into these instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold. Under these swap agreements, we receive a fixed price and pay a floating price based on certain indices for the relevant contract period. The options fix the price for us within the puts purchased and calls sold.

We formally document all relationships between hedging instruments and the items being hedged, including our risk management objective and strategy for undertaking the hedging transactions. This includes matching the natural gas futures and options contracts to the forecasted transactions. We assess, both at the inception of the hedge and on an ongoing basis, whether the derivatives are effective in offsetting changes in the forecasted cash flow of hedged items. If we determine that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of correlation between the hedging instrument and the underlying commodity, we will discontinue hedge accounting for the derivative and subsequent changes in fair value for the derivative will be recognized immediately within our consolidated statements of income.

We record derivatives on the balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as other comprehensive income (loss) and reclassify them to earnings as such transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within the consolidated statements of income as they occur. At June 30, 2005, we reflected a net hedging liability on our balance sheet of $19.9 million. Of the $19.3 million net loss in other comprehensive income (loss) at June 30, 2005, we will reclassify $10.3 million of losses to our consolidated statements of income over the next twelve month period as these contracts expire, and $9.0 million will be reclassified in later periods if the fair values of the instruments remain at current market values. Actual amounts that will be reclassified will vary as a result of future price changes. Ineffective hedge gains or losses are recorded within our consolidated statements of income while the hedge contract is open and may increase or decrease until settlement of the contract. We recognized a loss of $1.3 million and $1.9 million related to these hedging instruments for the three and six months ended June 30, 2005, respectively. These losses are included within natural gas and liquids revenue on our consolidated statements of income. There were no hedging instruments outstanding for the three and six months ended June 30, 2004.

A portion of our future natural gas sales is periodically hedged through the use of swaps and collar contracts. Realized gains and losses on the derivative instruments that are classified as effective hedges are reflected in the contract month being hedged as an adjustment to revenue.

As of June 30, 2005, we had the following NGLs, natural gas, crude oil and plant reduction volumes hedged:

Natural Gas Basis Swaps

Production Period Ended June 30,	Volumes (MMBTU)[(1)]	Average Fixed Price (per MMBTU)	Fair Value Liability[(3)] (in thousands)
2006	1,260,000	$ (0.537)	$ (83)
2007	1,140,000	(0.530)	(67)
2008	780,000	(0.541)	(55)
			$ (205)

Plant Volume Reduction Basis Swaps

Production Period Ended June 30,	Volumes (MMBTU)[(1)]	Average Fixed Price (per MMBTU)	Fair Value Asset[(3)] (in thousands)
2006	1,800,000	$ (0.478)	$ 12
2007	900,000	(0.495)	21
			$ 33

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Natural Gas Liquids Fixed Price Swaps

Production Period Ended June 30,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability(2) (in thousands)
2006	37,104,000	$0.662	$ (9,235)
2007	24,570,000	0.686	(5,821)
2008	9,954,000	0.698	(2,079)
			$(17,135)

Natural Gas Fixed Price Swaps

Production Period Ended June 30,	Volumes (MMBTU)(1)	Average Fixed Price (per MMBTU)	Fair Value Liability(3) (in thousands)
2006	1,200,000	$ 6.594	$ (1,419)
2007	1,140,000	7.131	(889)
2008	780,000	7.260	(235)
			$ (2,543)

Crude Oil Fixed Price Swaps

Production Period Ended June 30,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability(3) (in thousands)
2006	54,450	$51.558	$ (403)
2007	74,400	53.638	(358)
2008	55,200	55.875	(91)
			$ (852)

Plant Volume Reduction Fixed Price Swaps

Production Period Ended June 30,	Volumes (MMBTU)(1)	Average Fixed Price (per MMBTU)	Fair Value Asset(3) (in thousands)
2006	1,650,000	$ 7.205	$ 995
2007	900,000	7.255	548
			$ 1,543

Crude Oil Options

Production Period Ended June 30,	Option Type	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)
2006	Puts purchased	30,000	$ 30.00	$
2006	Calls sold	30,000	34.25	(721)
				$ (721)
			Total net liability	$(19,880)

(1) MMBTU represents million British Thermal Units.

(2) Fair value based upon management estimates, including forecasted forward NGL prices as a function of forward NYMEX natural gas and light crude prices.

(3) Fair value based on forward NYMEX natural gas and light crude prices, as applicable.

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ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures are effective at the reasonable assurance level.

There have been no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. In connection with our acquisitions of Spectrum in July 2004 and Elk City in April 2005, we have undertaken initial steps to implement a new version of our natural gas volume tracking and allocation software. The upgrade is expected to be completed by December 31, 2005 and is expected to enhance the overall operating effectiveness of our internal controls.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are a party to various routine legal proceedings arising out of the ordinary course of business. Management believes that the ultimate resolution of these actions, individually or in the aggregate, will not have a material adverse effect on our financial condition or results of operations.

On March 9, 2004, the Oklahoma Tax Commission (OTC) filed a petition against Spectrum alleging that Spectrum underpaid gross production taxes beginning in June 2000. The OTC is seeking a settlement of $5.0 million plus interest and penalties. We plan on defending ourselves vigorously. In addition, under the terms of the Spectrum purchase agreement, $14.0 million has been placed in escrow to cover the costs of any adverse settlement resulting from the petition and other indemnification obligations of the purchase agreement.

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

None

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None

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

None

ITEM 5. OTHER INFORMATION

None

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ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Purchase and Sale Agreement, dated March 8, 2005, by and among LG PL, LLC and LaGrange Acquisition as Sellers and Atlas Pipeline Partners, L.P. as Purchaser[(1)]
3.1	Second Amended and Restated Agreement of Limited Partnership [(2)]
3.2	Certificate of Limited Partnership of Atlas Pipeline Partners, L.P. [(3)]
10.1	Revolving Credit and Term Loan Agreement dated as of April 14, 2005 among Atlas Pipeline Partners, L.P., Wachovia Bank, National Association and the other parties thereto.[(1)]
31.1	Rule 13a-14(a)/15d-14(a) Certifications
31.2	Rule 13a-14(a)/15d-14(a) Certifications
32.1	Section 1350 Certifications
32.2	Section 1350 Certifications

(1) Previously filed as an exhibit to the Partnership s current report on Form 8-K filed on April 18, 2005 and incorporated herein by reference.

(2) Previously filed as an exhibit to the Partnership s registration statement on Form S-3, Registration No. 333-113523 and incorporated herein by reference.

(3) Previously filed as an exhibit to the Partnership s registration statement on

Form S-1, Registration No. 333-85193 and incorporated herein by reference.

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SIGNATURES
ATLAS PIPELINE PARTNERS, L.P.

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.

	By: Atlas Pipeline Partners GP, LLC, its General Partner
Date: August 9, 2005	By: /s/ EDWARD E. COHEN Edward E. Cohen Chairman of the Managing Board of the General Partner (Chief Executive Officer of the General Partner)
Date: August 9, 2005	By: /s/ MICHAEL L. STAINES Michael L. Staines President, Chief Operating Officer and Managing Board Member of the General Partner
Date: August 9, 2005	By: /s/ MATTHEW A. JONES Matthew A. Jones Chief Financial Officer of the General Partner
Date: August 9, 2005	By: /s/ SEAN P. MCGRATH Sean P. McGrath Chief Accounting Officer of the General Partner