ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 08, 2008
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2008

OR

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

Commission file number: 1-4998

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
1550 Coraopolis Heights 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 x No ¨

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes ¨ No x

The number of common units of the registrant outstanding on August 1, 2008 was 45,932,508.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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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, 2008	December 31, 2007
ASSETS		
Current assets:		
Cash and cash equivalents	$ 161,393	$ 11,980
Accounts receivable affiliates	3,793	3,334
Accounts receivable	192,304	147,360
Prepaid expenses and other	15,268	14,749
Total current assets	372,758	177,423
Property, plant and equipment, net	1,870,339	1,748,661
Intangible assets, net	206,426	219,203
Goodwill	676,860	709,283
Minority interest	2,013	2,163
Other assets, net	29,060	20,881
	$ 3,157,456	$ 2,877,614
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Current portion of long-term debt	$ 15	$ 34
Accounts payable	156,326	20,530
Accrued liabilities	49,166	43,487
Current portion of derivative liability	163,772	110,867
Accrued producer liabilities	123,808	80,698
Total current liabilities	493,087	255,616
Long-term derivative liability	340,678	118,646
Long-term debt, less current portion	1,271,518	1,229,392
Other long-term liability	659	
Commitments and contingencies		
Partners capital:		
Preferred limited partner s interests	38,231	37,076
Common limited partners interests	1,118,175	1,269,521
General partner s interest	30,261	29,413

Accumulated other comprehensive loss	(135,153)	(62,050)
Total partners capital	1,051,514	1,273,960
	$ 3,157,456	$ 2,877,614

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Revenue:				
Natural gas and liquids	$ 439,286	$ 104,792	$ 805,405	$ 206,968
Transportation, compression and other fees affiliates	11,421	8,458	20,580	16,178
Transportation, compression and other fees third parties	12,709	10,588	27,571	20,426
Other loss, net	(314,261)	(28,423)	(401,015)	(30,620)
Total revenue and other loss, net	149,155	95,415	452,541	212,952
Costs and expenses:				
Natural gas and liquids	349,980	87,102	626,644	174,912
Plant operating	14,831	4,515	29,766	9,045
Transportation and compression	4,301	3,210	8,113	6,322
General and administrative	8,631	6,608	13,001	12,311
Compensation reimbursement affiliates	1,390	798	2,519	1,428
Depreciation and amortization	26,196	6,671	52,021	13,205
Interest	19,385	7,327	39,766	14,086
Minority interest	3,112		5,202	
Total costs and expenses	427,826	116,231	777,032	231,309
Net loss	(278,671)	(20,816)	(324,491)	(18,357)
Preferred unit dividend effect		(3,756)		(3,756)
Preferred unit dividends	(650)		(787)	
Preferred unit imputed dividend cost		(735)	(505)	(1,234)
Net loss attributable to common limited partners and the general partner	$ (279,321)	$ (25,307)	$ (325,783)	$ (23,347)
Allocation of net loss attributable to common limited partners and the general partner:				
Common limited partners interest	$ (281,775)	$ (28,728)	$ (334,162)	$ (30,612)
General partner s interest	2,454	3,421	8,379	7,265
Net loss attributable to common limited partners and the general partner	$ (279,321)	$ (25,307)	$ (325,783)	$ (23,347)
Net loss attributable to common limited partners per unit:				
Basic	$ (7.16)	$ (2.20)	$ (8.56)	$ (2.34)
Diluted	$ (7.16)	$ (2.20)	$ (8.56)	$ (2.34)
Weighted average common limited partner units outstanding:				
Basic	39,329	13,080	39,046	13,080

Diluted	39,329	13,080	39,046	13,080

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

FOR THE SIX MONTHS ENDED JUNE 30, 2008

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units					Accumulated	
			Preferred	Common		Other	Total
			Limited	Limited	General	Comprehensive	Partners
	Preferred	Common	Partner	Partners	Partner	Loss	Capital
Balance at January 1, 2008	40,000	38,758,581	$ 37,076	$ 1,269,521	$ 29,413	$ (62,050)	$ 1,273,960
Issuance of common units		7,140,000		257,187			257,187
Preferred unit dividends			(137)				(137)
Capital contribution					5,452		5,452
Unissued common units under incentive plans				(1,600)			(1,600)
Issuance of units under incentive plans		33,367					
Distributions paid to common limited partners and the general partner				(72,501)	(12,983)		(85,484)
Distribution equivalent rights paid on unissued units under incentive plans				(270)			(270)
Other comprehensive loss						(73,103)	(73,103)
Net income (loss)			1,292	(334,162)	8,379		(324,491)
Balance at June 30, 2008	40,000	45,931,948	$ 38,231	$ 1,118,175	$ 30,261	$ (135,153)	$ 1,051,514

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, 2008	Six Months Ended June 30, 2007
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (324,491)	$ (18,357)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation and amortization	52,021	13,205
Non-cash loss on derivative value, net	201,834	30,826
Non-cash compensation expense (income)	(1,600)	4,262
Amortization of deferred finance costs	2,608	1,068
Minority interest	5,202	
Net distributions paid to minority interest holders	(5,052)	
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable and prepaid expenses and other	(48,699)	8,496
Accounts payable and accrued liabilities	184,788	(4,732)
Accounts payable and accounts receivable affiliates	(459)	3,693
Net cash provided by operating activities	66,152	38,461
CASH FLOWS FROM INVESTING ACTIVITIES:		
Acquisition purchase price adjustment	31,429	
Capital expenditures	(157,270)	(41,881)
Other	415	216
Net cash used in investing activities	(125,426)	(41,665)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Net proceeds from issuance of debt	244,854	
Repayment of debt	(122,820)	
Borrowings under credit facility	163,000	118,000
Repayments under credit facility	(248,000)	(82,000)
Net proceeds from issuance of common limited partner units	257,174	
General partner capital contributions	5,452	
Distributions paid to common limited partners and the general partner	(85,621)	(30,883)
Other	(5,352)	(1,273)
Net cash provided by financing activities	208,687	3,844
Net change in cash and cash equivalents	149,413	640
Cash and cash equivalents, beginning of period	11,980	1,795
Cash and cash equivalents, end of period	$ 161,393	$ 2,435

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, 2008

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Pipeline Partners, L.P. (the Partnership) is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the transmission, gathering and processing of natural gas. The Partnership s operations are conducted through subsidiary entities whose equity interests are owned by Atlas Pipeline Operating Partnership, L.P. (the Operating Partnership), a wholly-owned subsidiary of the Partnership. Atlas Pipeline Partners GP, LLC (the General Partner), through its general partner interests in the Partnership and the Operating Partnership, owns a 2% general partner interest in the consolidated pipeline operations, through which it manages and effectively controls both the Partnership and the Operating Partnership. The remaining 98% ownership interest in the consolidated pipeline operations consists of limited partner interests. The General Partner also owns 5,754,253 limited partner units in the Partnership. At June 30, 2008, the Partnership had 45,931,948 common limited partnership units, including the 5,754,253 common units held by the General Partner, and 40,000 $1,000 par value cumulative convertible preferred limited partnership units outstanding (see Note 4).

The Partnership s General Partner is a wholly-owned subsidiary of Atlas Pipeline Holdings, L.P. (AHD), a publicly-traded partnership (NYSE: AHD). Atlas America, Inc. and its affiliates (Atlas America), a publicly-traded company (NASDAQ: ATLS) which owns a 64.4% ownership interest in AHD at June 30, 2008, also owns 1,112,000 common limited partnership units, representing a 2.3% ownership interest in the Partnership, and a 48.3% ownership interest in Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a publicly-traded partnership (NYSE: ATN). Substantially all of the natural gas the Partnership transports in the Appalachian Basin is derived from wells operated by Atlas Energy.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2007 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, 2007. The results of operations for the three and six month periods ended June 30, 2008 may not necessarily be indicative of the results of operations for the full year ending December 31, 2008. Certain amounts in the prior year s consolidated financial statements have been reclassified to conform to the current year 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 its annual report on Form 10-K for the year ended December 31, 2007.

Principles of Consolidation and Minority Interest

The consolidated financial statements include the accounts of the Partnership, the Operating Partnership and the Operating Partnership s wholly-owned and majority-owned subsidiaries. The General Partner s interest in the Operating Partnership is reported as part of its overall 2% general partner interest in the Partnership. All material intercompany transactions have been eliminated.

The consolidated financial statements also include the operations of Chaney Dell natural gas gathering system and processing plants located in Oklahoma (Chaney Dell system) and the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (Midkiff/Benedum system). In July 2007, the Partnership acquired control of Anadarko Petroleum Corporation s (NYSE: APC) (Anadarko) 100% interest in the Chaney Dell system and its 72.8% undivided joint venture interest in the Midkiff/Benedum system (see Note 8). The transaction was effected by the formation of two joint venture companies which own the respective systems, of which the Partnership has a 95% interest and Anadarko has a 5% interest in each. The Partnership consolidates 100% of these joint ventures. The Partnership reflects Anadarko s 5% interest in the net income of these joint ventures as minority interest on its statements of operations. The Partnership also reflects Anadarko s investment in the net assets of the joint ventures as minority interest on its consolidated balance sheet. In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems, the joint ventures issued cash to Anadarko of $1.9 billion in return for a note receivable. This note receivable is reflected within minority interest on the Partnership s consolidated balance sheet.

The Midkiff/Benedum joint venture has a 72.8% undivided joint venture interest in the Midkiff/Benedum system, of which the remaining 27.2% interest is owned by Pioneer Natural Resources Company (NYSE: PXD) (Pioneer). Due to the Midkiff/Benedum system s status as an undivided joint venture, the Midkiff/Benedum joint venture proportionally consolidates its 72.8% ownership interest in the assets and liabilities and operating results of the Midkiff/Benedum system.

Use of Estimates

The preparation of the Partnership s consolidated financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership s consolidated financial statements, as well as the reported amounts of revenue and expense during the reporting periods. The Partnership s consolidated financial statements are based on a number of significant estimates, including the fair value of derivative instruments, the probability of forecasted transactions and stock compensation, all of which could affect the reported amounts of certain assets and liabilities. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions at the end of the month following the month of delivery. Consequently, the most current month s financial results were recorded using estimated volumes and commodity market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented for the three and six months ended June 30, 2008 represent actual results in all material respects (see Revenue Recognition accounting policy for further description).

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of the general partner s and the preferred unitholder s interests, by the weighted average number of common limited partner units outstanding during the period. The general partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2% interest and incentive distributions (see Note 5), with a priority allocation of net income in an amount equal to the general partner s incentive distributions, in accordance with the partnership agreement, and the remaining net income or loss allocated with respect to the general partner s and limited partners ownership interests. Diluted net income attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of phantom unit awards, as calculated by the treasury stock method, and the dilutive effect of convertible securities. Phantom units consist of common units issuable under the terms of the Partnership s long-term incentive plan and incentive compensation agreements (see Note 13). The following table sets forth the reconciliation of the weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Weighted average number of common limited partner units basic	39,329	13,080	39,046	13,080
Add: effect of dilutive unit incentive awards[(1)]				
Weighted average number of common limited partner units diluted	39,329	13,080	39,046	13,080

(1) For the three months ended June 30, 2008 and 2007, approximately 990,000 and 271,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the six months ended June 30, 2008 and 2007, approximately 984,000 and 258,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

For the periods presented in the table above, potential common limited partner units issuable upon conversion of the Partnership s 40,000 $1,000 par value cumulative convertible preferred limited partner units were excluded from the computation of diluted net income (loss) attributable to common limited partners as the impact of the conversion would have been anti-dilutive (see Note 4 for additional information regarding the conversion features of the preferred limited partner units).

Comprehensive Loss

Comprehensive loss includes net loss 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 loss, are referred to as other comprehensive loss and include only changes in the fair value of unsettled derivative contracts, which are accounted for as cash flow hedges. The following table sets forth the calculation of the Partnership s comprehensive loss (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Net loss	$ (278,671)	$ (20,816)	$ (324,491)	$ (18,357)
Preferred unit dividend effect		(3,756)		(3,756)
Preferred unit dividends	(650)		(787)	
Preferred unit imputed dividend cost		(735)	(505)	(1,234)
Net loss attributable to common limited partners and the general partner	(279,321)	(25,307)	(325,783)	(23,347)
Other comprehensive loss:				
Changes in fair value of derivative instruments accounted for as hedges	(127,994)	(9,453)	(109,409)	(18,120)
Add: adjustment for realized losses reclassified to net loss	18,663	7,650	36,306	10,697
Total other comprehensive loss	(109,331)	(1,803)	(73,103)	(7,423)
Comprehensive loss	$ (388,652)	$ (27,110)	$ (398,886)	$ (30,770)

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Revenue Recognition

Revenue in the Partnership s Appalachia segment is principally recognized at the time the natural gas is transported through its gathering systems. Under the terms of its natural gas gathering agreements with Atlas Energy and its affiliates, the Partnership receives fees for gathering natural gas from wells owned by Atlas Energy and by drilling investment partnerships sponsored by Atlas Energy. The fees received for the gathering services under the Atlas Energy agreements are generally the greater of 16% of the gross sales price for natural gas produced from the wells, or $0.35 or $0.40 per thousand cubic feet (mcf), depending on the ownership of the well. Substantially all natural gas gathering revenue in the Appalachia segment is derived from these agreements. Fees for transportation services provided to independent third parties whose wells are connected to the Partnership s Appalachia gathering systems are at separately negotiated prices.

The Partnership s Mid-Continent segment revenue primarily consists of the fees earned from its transmission, gathering and processing operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced natural gas liquids (NGLs), if any, off of delivery points on its systems. Under other agreements, the Partnership transports natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the Partnership s FERC-regulated transmission pipeline is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide for a set fee for gathering and processing raw natural gas. The Partnership s revenue is a function of the volume of natural gas that it gathers and processes and is not directly dependent on the value of the natural gas.

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this situation, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership owns a percentage of that commodity and is directly subject to its market value.

Keep-Whole Contracts. These contracts require the Partnership, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, the Partnership bears the economic risk (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 it paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of the Partnership s keep-whole contracts is minimized.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and condensate and the receipt of a delivery statement. This revenue is 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 (see Use of Estimates accounting policy for further description). The Partnership had unbilled revenues at June 30, 2008 and December 31, 2007 of $122.2 million and $86.8 million, respectively, which are included in accounts receivable and accounts receivable-affiliates within its consolidated balance sheets.

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Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average rate used to capitalize interest on borrowed funds was 5.7% and 8.0% for the three months ended June 30, 2008 and 2007, respectively, and 6.3% and 8.0% for the six months ended June 30, 2008 and 2007, respectively. The amount of interest capitalized was $2.3 million and $0.4 million for the three months ended June 30, 2008 and 2007, respectively, and $4.3 million and $1.0 million for the six months ended June 30, 2008 and 2007, respectively.

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions (see Note 8). The following table reflects the components of intangible assets being amortized at June 30, 2008 and December 31, 2007 (in thousands):

	June 30, 2008	December 31, 2007	Estimated Useful Lives In Years
Gross Carrying Amount:			
Customer contracts	$ 12,810	$ 12,810	8
Customer relationships	222,572	222,572	7-20
	$ 235,382	$ 235,382	
Accumulated Amortization:			
Customer contracts	$ (5,011)	$ (4,215)	
Customer relationships	(23,945)	(11,964)	
	$ (28,956)	$ (16,179)	
Net Carrying Amount:			
Customer contracts	$ 7,799	$ 8,595	
Customer relationships	198,627	210,608	
	$ 206,426	$ 219,203	

Statement of Financial Accounting Standards (SFAS) No. 142, Goodwill and Other Intangible Assets (SFAS No. 142) requires that intangible assets with finite useful lives be amortized over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives and residual values of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition. Amortization expense on intangible assets was $6.4 million and $0.6 million for the three months ended June 30, 2008 and 2007, respectively, and $12.8 million and $1.2 million for the six months ended June 30, 2008 and 2007, respectively. Amortization expense related to intangible assets is estimated to be $25.6 million for each of the next five calendar years commencing in 2008.

Goodwill

At June 30, 2008 and December 31, 2007, the Partnership had $676.9 million and $709.3 million, respectively, of goodwill recorded in connection with consummated acquisitions (see Note 8). The changes in the carrying amount of goodwill for the six months ended June 30, 2008 and 2007 were as follows (in thousands):

	Six Months Ended June 30,	
	2008	2007
Balance, beginning of period	$ 709,283	$ 63,441
Post-closing purchase price adjustment with seller and purchase price allocation adjustment Chaney Dell and Midkiff/Benedum systems acquisition	(2,217)	
Recovery of state sales tax initially paid on transaction Chaney Dell and Midkiff/Benedum systems acquisition	(30,206)	
Balance, end of period	$ 676,860	$ 63,441

The Partnership has adjusted its preliminary purchase price allocation for the acquisition of its Chaney Dell and Midkiff/Benedum systems since its July 2007 acquisition date by adjusting the estimated amounts allocated to goodwill, intangible assets and property, plant and equipment. Also, in April 2008, the Partnership received a $30.2 million cash reimbursement for sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems in July 2007. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition (see Note 8).

The Partnership tests its goodwill for impairment at each year end by comparing reporting unit fair values to carrying values. The evaluation of impairment under SFAS No. 142 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, 2007 resulted in no impairment and no impairment indicators have been noted as of June 30, 2008. The Partnership will continue to evaluate its goodwill at least annually and if impairment indicators arise, will reflect the impairment of goodwill, if any, within the consolidated statement of operations for the period in which the impairment is indicated.

Recently Adopted Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment to FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 is effective at the inception of an entity s first fiscal year beginning after November 15, 2007 and offers various options in electing to apply its provisions. The Partnership adopted SFAS No. 159 at January 1, 2008, and has elected not to apply the fair value option to any of its financial instruments.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value statements. In February 2008, the FASB issued FASB Staff Position SFAS No. 157-b, Effective Date of FASB Statement No. 157 , which provides for a one-year deferral of the effective date of SFAS No. 157 with regard to an entity s non-financial assets, non-financial liabilities or any non-recurring fair value measurement. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Partnership adopted SFAS No. 157 at January 1, 2008 with respect to its derivative instruments, which are measured at fair value within its financial statements. The provisions of SFAS No. 157 have not been applied to its non-financial assets and non-financial liabilities. See Note 10 for disclosures pertaining to the provisions of SFAS No. 157 with regard to the Partnership s financial instruments.

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Recently Issued Accounting Standards

In June 2008, the FASB issued Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 applies to the calculation of earnings per share (EPS) described in paragraphs 60 and 61 of FASB Statement No. 128, Earnings per Share for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. All prior-period EPS data presented shall be adjusted retrospectively to conform to the provisions of this FSP. The Partnership will apply the requirements of FSP EITF 03-6-1 upon its adoption on January 1, 2009 and it currently does not expect the adoption of FSP EITF 03-6-1 to have an impact on its financial position and results of operations.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies sources of accounting principles and the framework for selecting such principles used in the preparation of financial statements of nongovernmental entities presented in conformity with U.S. generally accepted accounting principles. SFAS No. 162 will be effective 60 days following the SEC s approval of AU Section 411, *The Meaning of* Present Fairly in Conformity with Generally Accepted Accounting Principles . The Partnership currently does not expect the adoption of SFAS No. 162 to have an impact on its financial position and results of operations.

In April 2008, the FASB issued Staff Position No. 142-3, Determination of Useful Life of Intangible Assets (FSP FAS 142-3). FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No 141(R), Business Combinations (SFAS No. 141(R)), and other U.S. Generally Accepted Accounting Principles. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. The guidance for determining the useful life of a recognized intangible asset should be applied prospectively to intangible assets acquired after the effective date. The disclosure requirements should be applied prospectively to all intangible assets recognized as of, and subsequent to, the effective date. The Partnership will apply the requirements of FSP FAS 142-3 upon its adoption on January 1, 2009 and it currently does not expect the adoption of FSP FAS 142-3 to have a material impact on its financial position and results of operations.

In March 2008, the FASB ratified the Emerging Issues Task Force (EITF) consensus on EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4), an update of EITF No. 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128 (EITF No. 03-6). EITF No. 07-4 requires the calculation of a Master Limited Partnership s net earnings per limited partner unit for each period presented according to distributions declared and participation rights in undistributed earnings as if all of the earnings for that period had been distributed. In periods with undistributed earnings above specified levels, the calculation per the two-class method results in an increased allocation of such undistributed earnings to the general partner and a dilution of earnings to the limited partners. EITF No. 07-4 is effective for fiscal years beginning after December 15, 2008, including interim periods within those fiscal years, and requires retrospective application of the guidance to all periods presented. Early adoption is prohibited. The Partnership does not believe the adoption of EITF No. 07-4 will have any impact on its financial position or results of operations. The Partnership s net earnings per limited partner unit calculated under the requirements of EITF No. 03-6 would not have differed under the requirements of EITF No. 07-4.

In March 2008, the FASB issued SFAS No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 amends the requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133), to require enhanced disclosure about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008, with early adoption encouraged. The Partnership is currently evaluating the impact the adoption of SFAS No. 161 will have on the disclosures regarding its derivative instruments.

In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 also requires consolidated net income to be reported, and disclosed on the face of the consolidated statement of operations, at amounts that include the amounts attributable to both the parent and the noncontrolling interest. Additionally, SFAS No. 160 establishes a single method for accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008. The Partnership will apply the requirements of SFAS No. 160 upon its adoption on January 1, 2009 and is currently evaluating whether SFAS No. 160 will have an impact on its financial position and results of operations.

In December 2007, the FASB issued SFAS No 141(R), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, Business Combinations (SFAS No. 141), however retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) requires an acquirer to recognize the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date, at their fair values as of that date, with specified limited exceptions. Changes subsequent to that date are to be recognized in earnings, not goodwill. Additionally, SFAS No. 141 (R) requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the noncontrolling interests in the acquiree, at the full amounts of their fair values. SFAS No. 141(R) is effective for business combinations occurring in fiscal years beginning on or after December 15, 2008. The Partnership will apply the requirements of SFAS No. 141(R) upon its adoption on January 1, 2009 and is currently evaluating whether SFAS No. 141(R) will have an impact on its financial position and results of operations.

NOTE 3 COMMON UNIT EQUITY OFFERINGS

On June 24, 2008, the Partnership sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also on June 24, 2008, the Partnership sold 1,112,000 common units to Atlas America and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. The Partnership also received a capital contribution from AHD of $5.4 million for AHD to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Notes 9 and 16).

In July 2007, the Partnership sold 25,568,175 common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25,568,175 common units sold by the

Partnership, 3,835,227 common units were purchased by AHD for $168.8 million. The Partnership also received a capital contribution from AHD of $23.1 million for AHD to maintain its 2.0% general partner interest in the Partnership. The Partnership utilized the net proceeds from the sale to partially fund the acquisition of control of the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and a 72.8% ownership interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (see Note 8).

NOTE 4 PREFERRED UNIT EQUITY OFFERING

On March 13, 2006, the Partnership entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for aggregate gross proceeds of $30.0 million. The Partnership also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital for $10.0 million on May 19, 2006, pursuant to the Partnership s right under the agreement to require Sunlight Capital to purchase such additional units. The preferred units were originally entitled to receive dividends of 6.5% per annum commencing on March 13, 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date for the Partnership s common units. In April 2007, the Partnership and Sunlight Capital agreed to amend the terms of the preferred units effective as of that date. The terms of the preferred units were amended to entitle them to receive dividends of 6.5% per annum commencing on March 13, 2008 and to be convertible, at Sunlight Capital s option, into common units commencing on the date immediately following the first record date for common unit distributions after March 13, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of the Partnership s common units as of the date of the notice of conversion. The Partnership may elect to pay cash rather than issue common units in satisfaction of a conversion request. The Partnership s preferred limited partner units were convertible into approximately 930,233 APL common limited partner units, subject to limitations within the agreement between the parties, as of June 30, 2008, with an estimated fair value of approximately $36.3 million based upon the market value of APL s common units as of that date.

The Partnership has the right to call the preferred units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.22. If not converted into common units or redeemed prior to May 2010, the preferred units will automatically be converted into Partnership common units in accordance with the agreement. In consideration of Sunlight Capital s consent to the amendment of the preferred units, the Partnership issued $8.5 million of its 8.125% senior unsecured notes due 2015 (see Note 11) to Sunlight Capital. The Partnership recorded the senior unsecured notes as long-term debt and a preferred unit dividend within partners capital on the Partnership s consolidated balance sheet and, during the three and six months ended June 30, 2007, reduced net income attributable to common limited partners and the general partner by $3.8 million of this amount, which was the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the preferred unitholder, on its consolidated statements of operations.

The preferred units are reflected on the Partnership s consolidated balance sheet as preferred equity within partners capital. In accordance with Securities and Exchange Commission Staff Accounting Bulletin No. 68, Increasing Rate Preferred Stock, the preferred units were originally recorded on the consolidated balance sheet at the amount of net proceeds received less an imputed dividend cost. The imputed dividend cost of $2.4 million was the result of the preferred units not having a dividend yield during the first year after their issuance on March 13, 2006 and was amortized in full as of March 12, 2007. As a result of the amended agreement, the Partnership recognized an imputed dividend cost of $2.5 million that was amortized during the year commencing March 13, 2007 and was based upon the present value of the net proceeds received using the 6.5% stated yield. During the six months ending June 30, 2008, the Partnership amortized the remaining $0.5 million of this imputed dividend cost, which is presented as an additional reduction of net loss to determine net loss attributable to common limited partners and the general partner on its consolidated statements of operations. Amortization of the imputed dividend cost was $0.7 million and $1.2 million for the three and six months ended June 30, 2007, respectively, based on the $2.4 million imputed cost during the initial year after the unit issuance.

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Sunlight Capital was entitled to receive the dividends on the preferred units pro rata from the March 13, 2008 commencement date. For the three months ended March 31, 2008, the Partnership recognized $0.1 million of preferred dividend cost, which is presented as a reduction of net loss to determine net loss attributable to common limited partners and the general partner on its consolidated statements of operations, and paid this dividend on May 15, 2008. For the three months ended June 30, 2008, the Partnership recognized $0.7 million of preferred dividend cost for dividends earned during the period, and will pay this dividend on August 14, 2008, the scheduled date of the Partnership s quarterly cash distribution (see Note 5). If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within partners capital on the Partnership s consolidated balance sheet.

NOTE 5 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2007 through June 30, 2008 were as follows:

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
February 14, 2007	December 31, 2006	$ 0.86	$ 11,249	$ 4,193
May 15, 2007	March 31, 2007	$ 0.86	$ 11,249	$ 4,193
August 14, 2007	June 30, 2007	$ 0.87	$ 11,380	$ 4,326
November 14, 2007	September 30, 2007	$ 0.91	$ 35,205	$ 4,498
February 14, 2008	December 31, 2007	$ 0.93	$ 36,051	$ 5,092
May 15, 2008	March 31, 2008	$ 0.94	$ 36,450	$ 7,891

In connection with the Partnership s acquisition of control of the Chaney Dell and Midkiff/Benedum systems (see Note 8), AHD, which holds all of the incentive distribution rights in the Partnership, agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. AHD also agreed that the resulting allocation of incentive distribution rights back to the Partnership would be after AHD receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter.

On July 22, 2008, the Partnership declared a cash distribution of $0.96 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2008. The $53.4 million distribution, including $9.3 million to the General Partner after the allocation of $5.0 million of its incentive distribution rights back to the Partnership, will be paid on August 14, 2008 to unitholders of record at the close of business on August 6, 2008.

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NOTE 6 PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment (in thousands):

	June 30, 2008	December 31, 2007	Estimated Useful Lives In Years
Pipelines, processing and compression facilities	$ 1,780,079	$ 1,633,454	15 40
Rights of way	170,655	168,359	20 40
Buildings	8,978	8,919	40
Furniture and equipment	8,196	7,235	3 7
Other	16,124	13,307	3 10
	1,984,032	1,831,274	
Less accumulated depreciation	(113,693)	(82,613)	
	$ 1,870,339	$ 1,748,661	

In July 2007, the Partnership acquired control of the Chaney Dell and Midkiff/Benedum systems (see Note 8). During the fourth quarter of 2007 and first quarter of 2008, the Partnership adjusted its preliminary purchase price allocation by adjusting the estimated amounts allocated to goodwill and property, plant, and equipment.

During the six months ended June 30, 2008, the Partnership recognized charges totaling $8.0 million within depreciation and amortization expense with respect to a write-off of costs related to a pipeline expansion project. The costs incurred consisted of a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

NOTE 7 OTHER ASSETS

The following is a summary of other assets (in thousands):

	June 30, 2008	December 31, 2007
Deferred finance costs, net of accumulated amortization of $13,960 and $11,352 at June 30, 2008 and December 31, 2007, respectively	$ 26,515	$ 18,227
Security deposits	2,543	2,498
Other	2	156
	$ 29,060	$ 20,881

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11). In June 2008, the Partnership recorded $1.2 million for accelerated amortization of deferred financing costs associated with the retirement of a portion of its term loan with a portion of the net proceeds from its issuance of senior notes (see Note 11).

NOTE 8 ACQUISITIONS

Chaney Dell and Midkiff/Benedum

In July 2007, the Partnership acquired control of Anadarko s 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). The Chaney Dell System includes 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum System includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which the Partnership contributed $1.9 billion and Anadarko contributed the Anadarko Assets.

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In connection with this acquisition, the Partnership reached an agreement with Pioneer, which currently holds a 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer has an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system, which began on June 15, 2008 and ends on November 1, 2008, and up to an additional 7.4% interest beginning on June 15, 2009 and ending on November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009). If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22% interest if fully exercised. The Partnership will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercises the purchase options. As of August 8, 2008, the Partnership has received no indication that Pioneer will exercise either of its options under the agreement.

The Partnership funded the purchase price in part from the private placement of $1.125 billion of its common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by AHD. AHD, which holds all of the incentive distribution rights in the Partnership, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to the Partnership through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. AHD also agreed that the resulting allocation of incentive distribution rights back to the Partnership would be after AHD receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (see Note 5). The Partnership funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and borrowings from its senior secured revolving credit facility that matures in July 2013 (see Note 11).

The acquisition was accounted for using the purchase method of accounting under SFAS No. 141. The following table presents the purchase price allocation, including professional fees and other related acquisition costs, to the assets acquired and liabilities assumed in the acquisition, based on their fair values at the date of the acquisition (in thousands):

Accounts receivable	$ 745
Prepaid expenses and other	4,587
Property, plant and equipment	1,030,464
Intangible assets customer relationships	205,312
Goodwill	613,420
Total assets acquired	1,854,528
Accounts payable and accrued liabilities	(1,499)
Net cash paid for acquisition	$ 1,853,029

The Partnership recorded goodwill in connection with this acquisition as a result of Chaney Dell s and Midkiff/Benedum s significant cash flow and strategic industry position. In April 2008, the Partnership received a $30.2 million cash reimbursement for state sales tax initially paid on its transaction to acquire the Chaney Dell and Midkiff/Benedum systems. The $30.2 million was initially capitalized as an acquisition cost and allocated to the assets acquired, including goodwill, based upon their estimated fair values at the date of acquisition. Based upon the reimbursement of the sales tax paid in April 2008, the Partnership reduced goodwill recognized in connection with the acquisition. The results of Chaney Dell s and Midkiff/Benedum s operations are included within the Partnership s consolidated financial statements from the date of acquisition.

The following data presents pro forma revenue and net income (loss) for the Partnership for the three and six months ended June 30, 2008 and 2007 as if the acquisition discussed above, the equity offering in July 2007 (see Note 3), proceeds of $830.0 million from a senior unsecured term loan (see Note 11), borrowings under its senior secured revolving credit facility (see Note 11), and the April 2007 issuances of senior notes (see Notes 4 and 11) had occurred on January 1, 2007. The Partnership has prepared these unaudited 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 this acquisition and these financing transactions at the beginning of the periods shown below or the results that will be attained in the future (in thousands, except per unit data):

	Three Months Ended June 30,		**Six Months Ended June 30,**	
	2008	**2007**	**2008**	**2007**

Total revenue and other loss, net	$ 149,155	$ 273,016	$ 452,541	$ 534,184
Net loss	$ (278,671)	$ (4,291)	$ (324,491)	$ (13,649)
Net loss attributable to common limited partners and the general partner	$ (279,321)	$ (5,026)	$ (325,783)	$ (18,624)
Net loss attributable to common limited partners per unit:				
Basic	$ (7.16)	$ (0.23)	$ (8.56)	$ (0.67)
Diluted	$ (7.16)	$ (0.23)	$ (8.56)	$ (0.67)

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NOTE 9 DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps and options, in connection with its commodity price and interest rate risk management activities. The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. It also enters into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold or interest payments on the underlying debt instrument is due. Under swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133.

The Partnership formally documents all relationships between hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching derivative contracts to the forecasted transactions. The Partnership assesses, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. 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 adequate correlation between the hedging instrument and the underlying item being hedged, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by the Partnership through the utilization of market data, will be recognized immediately within other income (loss) in its consolidated statements of operations. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassifies the portion relating to commodity derivatives to natural gas and liquids revenue and the portion relating to interest rate derivatives to interest expense within its consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, the Partnership recognizes changes in fair value within other income (loss) in its consolidated statements of operations as they occur.

During June 2008, the Partnership made net payments of $170.4 million related to the early termination of crude oil derivative contracts that were entered into as proxy hedges for the prices received on the ethane and propane portion of its NGL equity volume. These derivative contracts were put into place simultaneously with the Partnership s acquisition of the Chaney Dell and Midkiff/

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Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. During the three and six months ended June 30, 2008, the Partnership recognized a derivative expense of $162.1 million related to the termination of these derivative instruments, including a non-cash portion of $46.3 million, within other loss, net on its consolidated statements of operations. The Partnership also recognized a cash derivative expense of $0.3 million within natural gas and liquids revenue on its consolidated statements of operations. In addition, $54.3 million will be reclassified from accumulated other comprehensive loss within partner s capital on the Partnership s consolidated balance sheet and recognized as non-cash derivative expenses during the period beginning on July 1, 2008 and ending on December 31, 2009, the period the derivatives were originally scheduled to be settled, as a result of the early termination of certain crude oil derivatives that were classified as cash flow hedges in accordance with SFAS No. 133 at the date of termination. During July 2008, the Partnership paid an additional $93.6 million related to the early termination of the crude oil derivative contracts that relate to production periods through the end of 2009 (see Note 16).

At June 30, 2008, the Partnership has interest rate derivative contracts having aggregate notional principal amounts of $450.0 million, which were designated as cash flow hedges. Under the terms of these agreements, the Partnership will pay weighted average interest rates of 3.02%, plus the applicable margin as defined under the terms of its revolving credit facility (see Note 11), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. These derivatives effectively convert $450.0 million of the Partnership s floating rate debt under the term loan and revolving credit facility to fixed-rate debt. The interest rate swap agreements are effective as of June 30, 2008 and expire during periods ranging from January 30, 2010 through April 30, 2010.

Derivatives are recorded on the Partnership s consolidated balance sheet as assets or liabilities at fair value. At June 30, 2008 and December 31, 2007, the Partnership reflected net derivative liabilities on its consolidated balance sheets of $504.5 million and $229.5 million, respectively. Of the $135.2 million of net loss in accumulated other comprehensive loss within partners capital on the Partnership s consolidated balance sheet at June 30, 2008, if the fair values of the instruments remain at current market values, the Partnership will reclassify $70.6 million of losses to the Partnership s consolidated statements of operations over the next twelve month period as these contracts expire, consisting of $70.2 million of losses to natural gas and liquids revenue and $0.4 million to interest expense. Aggregate losses of $64.6 million will be reclassified to the Partnership s consolidated statements of operations in later periods, consisting of $66.6 million of losses to natural gas and liquids revenue and $2.0 million of gains to interest expense. Actual amounts that will be reclassified will vary as a result of future price changes.

On June 3, 2007, the Partnership signed definitive agreements to acquire control of the Chaney Dell and Midkiff/Benedum systems (see Note 8). In connection with certain additional agreements entered into to finance this transaction, the Partnership agreed as a condition precedent to closing that it would hedge 80% of its projected natural gas, NGL and condensate production volume for no less than three years from the closing date of the transaction. During June 2007, the Partnership entered into derivative instruments to hedge 80% of the projected production of the Anadarko Assets to be acquired as required under the financing agreements. The production volume of the Anadarko Assets to be acquired was not considered to be probable forecasted production under SFAS No. 133 at the date these derivatives were entered into because the acquisition of the Anadarko Assets had not yet been completed. Accordingly, the Partnership recognized the instruments as non-qualifying for hedge accounting at inception with subsequent changes in the derivative value recorded within other income (loss) in its consolidated statements of operations. The Partnership recognized a non-cash loss of $18.8 million related to the change in value of derivatives entered into specifically for the Chaney Dell and Midkiff/Benedum systems from the time the derivative instruments were entered into to the date of closing of the acquisition during the year ended December 31, 2007. Upon closing of the acquisition in July 2007, the production volume of the Anadarko Assets acquired was considered probable forecasted production under SFAS No. 133. The Partnership designated many of these instruments as cash flow hedges and evaluated these derivatives under the cash flow hedge criteria in accordance with SFAS No. 133.

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In connection with the Chaney Dell and Midkiff/Benedum acquisition, the Partnership reached an agreement with Pioneer granting it an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system, which began on June 15, 2008 and ends on November 1, 2008, and an additional 7.4% interest beginning on June 15, 2009 and ending on November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009) (see Note 8). As of August 8, 2008, the Partnership has received no indication that Pioneer will exercise either of its options under the agreement. If Pioneer does exercise either of these options, the Partnership will discontinue hedge accounting for the derivative instruments covering the portion of the forecasted production of the Midkiff/Benedum system sold to Pioneer and will evaluate these derivative instruments to determine if they can be documented to match other forecasted production the Partnership may have.

The following table summarizes the Partnership s derivative activity for the periods indicated (amounts in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Loss from cash settlement of qualifying hedge instruments(1)	$ (33,152)	$ (7,650)	$ (50,795)	$ (10,697)
Gain/(loss) from change in market value of non- qualifying derivatives(2)	(136,736)	(18,835)	(207,932)	(20,137)
Gain/(loss) from change in market value of ineffective portion of qualifying derivatives(2)	1,934	(9,714)	(3,726)	(10,689)
Loss from cash settlement of non-qualifying derivatives(2)	(184,564)		(196,489)	
Loss from cash settlement of interest rate derivatives(3)	(194)		(194)	

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.
(2) Included within other loss, net on the Partnership s consolidated statements of operations.
(3) Included within interest expense on the Partnership s consolidated statements of operations.

As of June 30, 2008, the Partnership had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Interest Fixed Rate Swap

Term	Notional Amount	Type		Contract Period Ended December 31,	Fair Value Asset/(Liability)(1) (in thousands)
January 2008 - January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	2008	$ (250)
				2009	977
				2010	170
					$ 897
April 2008 - April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2008	$ (635)
				2009	589
				2010	726
					$ 680

Natural Gas Liquids Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability[2] (in thousands)
2008	14,868,000	$ 0.697	$ (13,921)
2009	8,568,000	$ 0.746	(7,069)
			$ (20,990)

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Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(3) (in thousands)	Option Type
2008	600,000	40,068,000	$ 60.00	$ 4	Puts purchased
2008	126,000	11,219,040	$ 127.55	(962)	Puts sold(4)
2008	126,000	11,219,040	$ 140.00	1,821	Calls purchased(4)
2008	946,800	51,529,968	$ 80.13	(57,308)	Calls sold
2009	1,056,000	94,026,240	$ 126.05	(11,425)	Puts sold(4)(5)
2009	1,056,000	94,026,240	$ 143.00	18,033	Calls purchased(4)(5)
2009	3,636,000	219,602,880	$ 79.51	(215,989)	Calls sold(5)
2010	3,127,500	202,370,490	$ 81.09	(176,190)	Calls sold
2011	606,000	32,578,560	$ 95.56	(26,751)	Calls sold
2012	450,000	24,192,000	$ 97.10	(18,820)	Calls sold
				$ (487,587)	

Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(6)	Average Fixed Price (per mmbtu) (6)	Fair Value Liability(3) (in thousands)
2008	2,742,000	$ 8.823	$ (12,942)
2009	5,724,000	$ 8.611	(22,102)
2010	4,560,000	$ 8.526	(12,744)
2011	2,160,000	$ 8.270	(5,423)
2012	1,560,000	$ 8.250	(3,888)
			$ (57,099)

Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(6)	Average Fixed Price (per mmbtu)(6)	Fair Value Asset(3) (in thousands)
2008	2,742,000	$ (0.744)	$ 2,605
2009	5,724,000	$ (0.558)	2,706
2010	4,560,000	$ (0.622)	1,048
2011	2,160,000	$ (0.664)	37
2012	1,560,000	$ (0.601)	27
			$ 6,423

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)[(6)]	Average Fixed Price (per mmbtu)[(6)]	Fair Value Asset[(3)] (in thousands)
2008	8,130,000	$ 9.001[(7)]	$ 37,081
2009	15,564,000	$ 8.680	59,019
2010	8,940,000	$ 8.580	25,632
2011	2,160,000	$ 8.270	5,423
2012	1,560,000	$ 8.250	3,888
			$ 131,043

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Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(6)	Average Fixed Price (per mmbtu)(6)	Fair Value Asset/(Liability)(3) (in thousands)
2008	8,130,000	$ (1.114)	$ (8,045)
2009	15,564,000	$ (0.654)	(9,633)
2010	8,940,000	$ (0.600)	(2,638)
2011	2,160,000	$ (0.700)	116
2012	1,560,000	$ (0.610)	58
			$ (20,142)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)	Average Fixed Price (per barrel)	Fair Value Liability(3) (in thousands)
2008	25,200	$ 60.427	$ (2,031)
2009	33,000	$ 62.700	(2,578)
			$ (4,609)

Crude Oil Participating Swaps for NGLs(8)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset (3) (in thousands)	Option Type
2008	126,000	11,219,040	$ 137.00	$ 748	Participating swaps

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability(3) (in thousands)	Option Type
2008	10,800	$ 60.000	$	Puts purchased
2008	138,000	$ 78.055	(8,615)	Calls sold
2009	306,000	$ 80.017	(23,574)	Calls sold
2010	234,000	$ 83.027	(15,633)	Calls sold
2011	72,000	$ 87.296	(3,583)	Calls sold
2012	48,000	$ 83.944	(2,409)	Calls sold
			$ (53,814)	
		Total net liability	$ (504,450)	

(1) Fair value based on independent, third-party statements, supported by observable levels at which transactions are executed in the marketplace.

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

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

(4) Puts sold and calls purchased in 2008 and 2009 represent collars entered into by the Partnership as offsetting positions for the calls sold related to ethane and propane production. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

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(5) A portion of these positions were paid off during July 2008 as a result of the Partnership s early termination of certain crude oil derivative contracts (see Note 16).

(6) Mmbtu represents million British Thermal Units.

(7) Includes the Partnership s premium received from its sale of an option for it to sell 468,000 mmbtu of natural gas for the year ended December 31, 2008 at $15.50 per mmbtu.

(8) Represents derivative instruments that combine a swap and a put option with the same strike price.

NOTE 10 FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership adopted the provisions of SFAS No. 157 at January 1, 2008. SFAS No. 157 establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. SFAS No. 157 s hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 Unobservable inputs that reflect the entity s own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

The Partnership uses the fair value methodology outlined in SFAS No. 157 to value the assets and liabilities for its respective outstanding derivative contracts (see Note 9). All of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and crude oil options. The Partnership s Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. The Partnership s interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for the Partnerships NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for the Partnership s crude oil options (including those associated with NGL sales) are based on forward price curves developed by the related financial institution based upon current quoted prices for crude oil futures, and therefore are defined at Level 3. In accordance with SFAS No. 157, the following table represents the Partnership s assets and liabilities recorded at fair value as of June 30, 2008 (in thousands):

	Level 1	Level 2	Level 3	Total
Commodity based derivatives	$	$ 55,616	$ (561,643)	$ (506,027)
Interest rate swap based derivatives	$	$ 1,577	$	$ 1,577
Total	$	$ 57,193	$ (561,643)	$ (504,450)

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The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and crude oil options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments as of June 30, 2008 (in thousands):

	NGL Fixed Price Swaps	Crude Oil Sales Options (assoc. with NGL Volume)	Crude Oil Sales Options	Total
Balance December 31, 2007	$ (33,624)	$ (24,740)	$ (145,418)	$ (203,782)
New options contracts			(8,215)	(8,215)
Cash settlements from unrealized gain[1]	1,142	3,157	215,717	220,016
Cash settlements from other comprehensive income (loss) [1]	20,048	4,201	11,969	36,218
Net change in unrealized gain (loss) [2]	(1,005)	2,513	(425,381)	(423,873)
Deferred option premium recognition		(6,776)	(35,205)	(41,981)
Net change in other comprehensive income (loss)	(7,551)	(32,169)	(100,306)	(140,026)
Balance June 30, 2008	$ (20,990)	$ (53,814)	$ (486,839)	$ (561,643)

(1) Included within natural gas and liquids revenue on the Partnership s consolidated statements of operations.

(2) Included within other loss, net on the Partnership s consolidated statements of operations.

NOTE 11 DEBT

Total debt consists of the following (in thousands):

	June 30, 2008	December 31, 2007
Revolving credit facility	$ 20,000	$ 105,000
Term loan	707,180	830,000
8.125 % Senior notes due 2015	294,338	294,392
8.75% Senior notes due 2018	250,000	
Other debt	15	34
Total debt	1,271,533	1,229,426
Less current maturities	(15)	(34)
Total long term debt	$ 1,271,518	$ 1,229,392

Term Loan and Credit Facility

At June 30, 2008, the Partnership has a senior secured credit facility with a syndicate of banks which consists of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear 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 revolving credit facility borrowings at June 30, 2008 was 4.4%, and the weighted average interest rate on the outstanding term loan borrowings at June 30, 2008 was 5.2%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $22.0 million was outstanding at June 30, 2008. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheet.

On June 12, 2008, the Partnership entered into an amendment to its revolving credit facility and term loan agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to the Partnership s early termination of certain crude oil derivative contracts (see Note 9) in calculating its Consolidated EBITDA. Pursuant to this amendment, on June 27, 2008, the Partnership repaid $122.8

million of its outstanding term loan and repaid $120.0 million of outstanding borrowings under the credit facility with proceeds from its issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, on June 27, 2008 the Partnership s lenders increased their commitments for the revolving credit facility by $80.0 million to $380.0 million.

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, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures, and by the guaranty of each of its consolidated subsidiaries other than the joint venture companies. 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 its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is in compliance with these covenants as of June 30, 2008. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with the new credit facility, the Partnership agreed to remit an underwriting fee to the lead underwriting bank of the credit facility of 0.75% of the aggregate principal amount of the term loan outstanding on January 23, 2008. In January 2008, the Partnership and the underwriting bank agreed to extend the agreement through June 30, 2008. In June 2008, the Partnership and the underwriting bank agreed to extend the agreement through November 30, 2008 and amend the underwriting fee to be 0.50% of the aggregate principal amount of the term loan outstanding as of that date.

The events which constitute an event of default for the Partnership s credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner. The credit facility requires the Partnership to maintain a ratio of funded debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.5 to 1.0, increasing to 2.75 to 1.0 commencing September 30, 2008. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of June 30, 2008, the Partnership s ratio of funded debt to EBITDA was 4.6 to 1.0 and its interest coverage ratio was 3.5 to 1.0.

The Partnership is unable to borrow under its credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement.

Senior Notes

At June 30, 2008, the Partnership had $250.0 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $293.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with $0.8 million of unamortized premium received as of June 30, 2008. The 8.75% Senior Notes were issued on June 27, 2008 in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $244.9 million, after underwriting commissions and other transaction costs. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. A similar redemption option exists prior to December 15, 2008 with respect to the 8.125% Senior Notes. The Senior Notes in the aggregate are also subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its Credit Facility.

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Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of June 30, 2008.

In connection with the issuance of the 8.75% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If the Partnership does not meet the aforementioned deadline, the 8.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the Partnership has caused the exchange offer to be consummated.

NOTE 12 COMMITMENTS AND CONTINGENCIES

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

As of June 30, 2008, the Partnership is committed to expend approximately $158.6 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

NOTE 13 STOCK COMPENSATION

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 its General Partner s managing board. 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, 2008.

A phantom unit entitles a grantee to receive a common unit, without payment of an exercise price, 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 limited partner 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, 2008, phantom units granted under the LTIP generally had vesting periods of four years. The vesting of awards may also be contingent upon the attainment of predetermined performance targets, which could increase or decrease the actual award settlement, as determined by the Committee, although no awards currently outstanding contain any such provision. 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 in the LTIP. Of the units outstanding under the LTIP at June 30, 2008, 55,588 units will vest within the following twelve months. All units outstanding under the LTIP at June 30, 2008 include DERs granted to the participants by the Committee. The amounts paid with respect to DERs were $0.2 million for the three months ended June 30, 2008 and 2007, respectively, and $0.3 million for both the six months ended June 30, 2008 and 2007, respectively. These amounts were recorded as reductions of Partners Capital on the Partnership s consolidated balance sheet.

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The Partnership follows the provisions of SFAS No. 123(R), Share-Based Payment , as revised (SFAS No. 123(R)). Generally, the approach to accounting in SFAS No. 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Outstanding, beginning of period	171,087	183,859	129,746	159,067
Granted[(1)]	345	303	54,296	25,095
Matured[(2)]	(21,509)		(33,369)	
Forfeited			(750)	
Outstanding, end of period[(3)]	149,923	184,162	149,923	184,162
Non-cash compensation expense recognized (in thousands)	$ 697	$ 973	$ 1,183	$ 1,874

(1) The weighted average price for phantom unit awards on the date of grant, which is utilized in the calculation of compensation expense and does not represent an exercise price to be paid by the recipient, was $43.42 and $49.42 for awards granted for the three months ended June 30, 2008 and 2007, respectively, and $44.43 and $50.09 for awards granted for the six months ended June 30, 2008 and 2007, respectively.

(2) The intrinsic value for phantom unit awards exercised during the three and six months ended June 30, 2008 was approximately $0.9 million and $1.4 million, respectively. There were no phantom unit awards exercised during the three and six months ended June 30, 2007.

(3) The aggregate intrinsic value for phantom unit awards outstanding as of June 30, 2008 was $5.9 million.

At June 30, 2008, the Partnership had approximately $3.4 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIP based upon the fair value of the awards.

Incentive Compensation Agreements

The Partnership has incentive compensation agreements which have granted awards to certain key employees retained from previously consummated acquisitions. These individuals were entitled to receive common units of the Partnership upon the vesting of the awards, which was dependent upon the achievement of certain predetermined performance targets through September 30, 2007. At September 30, 2007, the predetermined performance targets were achieved and all of the awards under the incentive compensation agreements vested. Of the total common units to be issued under the incentive compensation agreements, 58,822 common units were issued during the year ended December 31, 2007. The ultimate number of common units estimated to be issued under the incentive compensation agreements will be determined principally by the financial performance of certain Partnership assets for the year ended December 31, 2008 and the market value of the Partnership s common units at December 31, 2008. The incentive compensation agreements also dictate that no individual covered under the agreements shall receive an amount of common units in excess of one percent of the outstanding common units of the Partnership at the date of issuance. Common unit amounts due to any individual covered under the agreements in excess of one percent of the outstanding common units of the Partnership shall be paid in cash.

The Partnership recognized compensation expense (income) of $0.5 million and $1.5 million for the three months ended June 30, 2008 and 2007, respectively, and ($2.8) million and $2.4 million for the six months ended June 30, 2008 and 2007, respectively, related to the vesting of awards under these incentive compensation agreements. The non-cash compensation expense adjustments for the six months ended June 30, 2008 were principally attributable to changes in our common unit market price, which is utilized in the estimation of the non-cash compensation expense for these awards, at June 30, 2008 when compared with the price at earlier periods and adjustments based upon the achievement of actual financial performance targets through June 30, 2008. The vesting period for such awards concluded on September 30, 2007. Management anticipates that adjustments will be recorded in future periods with respect to the awards under the incentive compensation agreements based upon the actual financial performance of the assets in future periods in comparison to their estimated performance and the movement in the market value of the Partnership s common units. Based upon management s estimate of the probable outcome of the performance targets at June 30, 2008, 963,974 common unit awards are ultimately expected to be issued under these agreements during the year ended December 31, 2009, which represents the total amount of common units expected to be issued under the incentive compensation agreements. The Partnership follows SFAS No. 123(R) and recognized compensation expense related to these awards based upon the fair value method.

NOTE 14 RELATED PARTY TRANSACTIONS

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 Atlas America. 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. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to their employees who perform services for the Partnership 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 Atlas America based on the number of its employees who devote their time to activities on the Partnership s 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 $1.4 million and $0.8 million for the three months ended June 30, 2008 and 2007, respectively, and $2.5 million and $1.4 million for the six months ended June 30, 2008 and 2007, respectively, for compensation and benefits related to their executive officers. For the three months ended June 30, 2008 and 2007, direct reimbursements were $12.1 million and $6.2 million, respectively, and $21.5 million and $12.2 million for the six months ended June 30, 2008 and 2007, 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 between the Partnership and Atlas Energy, Atlas Energy 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 Energy 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 15 SEGMENT INFORMATION

The Partnership has two reportable segments: natural gas transmission, gathering and processing located in the Appalachian Basin area (Appalachia) of eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee, and transmission, gathering and processing located in the Mid-Continent area (Mid-Continent) of primarily Oklahoma, northern and western Texas, the Texas Panhandle, Arkansas, southern Kansas and southeastern Missouri. Appalachia revenues are principally based on contractual arrangements with Atlas Energy and its affiliates. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and transport of natural gas. These reportable segments reflect the way the Partnership manages its operations.

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The following summarizes the Partnership s reportable segment data for the periods indicated (in thousands):

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Mid-Continent				
Revenue:				
Natural gas and liquids	$ 438,163	$ 104,792	$ 803,322	$ 206,968
Transportation, compression and other fees	12,388	10,571	27,003	20,390
Other loss	(314,350)	(28,506)	(401,215)	(30,785)
Total revenue and other loss	136,201	86,857	429,110	196,573
Costs and expenses:				
Natural gas and liquids	349,475	87,102	625,657	174,912
Plant operating	14,831	4,515	29,766	9,045
Transportation and compression	1,656	1,780	3,154	3,500
General and administrative	6,977	4,806	9,507	8,700
Depreciation and amortization	24,652	5,555	49,095	11,015
Minority interest	3,112		5,202	
Total costs and expenses	400,703	103,758	722,381	207,172
Segment loss	$ (264,502)	$ (16,901)	$ (293,271)	$ (10,599)
Appalachia				
Revenue:				
Natural gas and liquids	$ 1,123	$	$ 2,083	$
Transportation, compression and other fees affiliates	11,421	8,458	20,580	16,178
Transportation, compression and other fees third parties	321	17	568	36
Other income	89	83	200	165
Total revenue and other income	12,954	8,558	23,431	16,379
Costs and expenses:				
Natural gas and liquids	505		987	
Transportation and compression	2,645	1,430	4,959	2,822
General and administrative	1,523	1,300	3,007	2,520
Depreciation and amortization	1,544	1,116	2,926	2,190
Total costs and expenses	6,217	3,846	11,879	7,532
Segment profit	$ 6,737	$ 4,712	$ 11,552	$ 8,847
Reconciliation of segment profit (loss) to net loss:				
Segment profit (loss):				
Mid-Continent	$ (264,502)	$ (16,901)	$ (293,271)	$ (10,599)
Appalachia	6,737	4,712	11,552	8,847
Total segment loss	(257,765)	(12,189)	(281,719)	(1,752)
Corporate general and administrative expenses	(1,521)	(1,300)	(3,006)	(2,519)
Interest expense(1)	(19,385)	(7,327)	(39,766)	(14,086)

Net loss	$ (278,671)	$ (20,816)	$ (324,491)	$ (18,357)
Capital Expenditures:				
Mid-Continent	$ 64,689	$ 22,251	$ 134,372	$ 36,092
Appalachia	8,512	3,001	22,898	5,789
	$ 73,201	$ 25,252	$ 157,270	$ 41,881

(1) The Partnership notes that interest expense has not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

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	June 30, 2008	December 31, 2007
Balance sheet		
Total assets:		
Mid-Continent	$ 2,712,505	$ 2,813,049
Appalachia	258,487	43,860
Corporate other	186,464	20,705
	$ 3,157,456	$ 2,877,614
Goodwill:		
Mid-Continent	$ 674,555	$ 706,978
Appalachia	2,305	2,305
	$ 676,860	$ 709,283

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

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Natural gas and liquids:				
Natural gas	$ 188,520	$ 37,347	$ 328,304	$ 84,110
NGLs	211,033	60,056	409,726	106,828
Condensate	22,324	2,144	35,003	4,733
Other (1)	17,409	5,245	32,372	11,297
Total	$ 439,286	$ 104,792	$ 805,405	$ 206,968
Transportation, compression and other fees:				
Affiliates	$ 11,421	$ 8,458	$ 20,580	$ 16,178
Third Parties	12,709	10,588	27,571	20,426
Total	$ 24,130	$ 19,046	$ 48,151	$ 36,604

(1) Includes treatment, processing, and other revenue associated with the products noted.

NOTE 16 SUBSEQUENT EVENT

During July 2008, the Partnership made payments of $93.6 million related to the early termination of crude oil derivative contracts that were entered into as proxy hedges for the prices received on the ethane and propane portion of its NGL equity volume. These derivative contracts were put into place simultaneously with the Partnership s acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to 2009 production periods. These payments were made in connection with the Partnership s early termination of other crude oil derivative contracts in June 2008 (see Note 9).

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 1A, under the caption

Risk Factors , in our annual report on Form 10-K for 2007. 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 related notes appearing elsewhere in this report.

General

We are a publicly-traded Delaware limited partnership whose common units are listed on the New York Stock Exchange under the symbol APL . Our principal business objective is to generate cash for distribution to our unitholders. We are a leading provider of natural gas gathering services in the Anadarko, Arkoma and Permian Basins and the Golden Trend in the southwestern and mid-continent United States and the Appalachian Basin in the eastern United States. In addition, we are a leading provider of natural gas processing and treatment services in Oklahoma and Texas. We also provide interstate gas transmission services in southeastern Oklahoma, Arkansas, southern Kansas and southeastern Missouri. Our business is conducted in the midstream segment of the natural gas industry through two reportable segments: our Mid-Continent operations and our Appalachian operations.

Through our Mid-Continent operations, we own and operate:

- a FERC-regulated, 565-mile interstate pipeline system (Ozark Gas Transmission) that extends from southeastern Oklahoma through Arkansas and into southeastern Missouri and which has throughput capacity of approximately 400 MMcfd;
- eight active natural gas processing plants with aggregate capacity of approximately 750 MMcfd and one treating facility with a capacity of approximately 200 MMcfd, located in Oklahoma and Texas; and
- 7,870 miles of active natural gas gathering systems located in Oklahoma, Arkansas, Kansas and Texas, which transport gas from wells and central delivery points in the Mid-Continent region to our natural gas processing and treating plants or Ozark Gas Transmission, as well as third party pipelines.

Through our Appalachian operations, we own and operate 1,600 miles of natural gas gathering systems located in eastern Ohio, western New York, western Pennsylvania and northeastern Tennessee. Through an omnibus agreement and other agreements between us and Atlas America, Inc., (Atlas America NASDAQ: ATLS) and its affiliates, including Atlas Energy Resources, LLC and subsidiaries (Atlas Energy), a leading sponsor of natural gas drilling investment partnerships in the Appalachian Basin and a publicly-traded company (NYSE: ATN), we gather substantially all of the natural gas for our Appalachian Basin operations from wells operated by Atlas Energy. Among other things, the omnibus agreement requires Atlas Energy to connect to our gathering systems wells it operates that are located within 2,500 feet of our gathering systems. We are also party to natural gas gathering agreements with Atlas America and Atlas Energy under which we receive gathering fees generally equal to a percentage, typically 16%, of the selling price of the natural gas we transport.

Recent Events

On June 24, 2008, we sold 5,750,000 common units in a public offering at a price to the public of $37.52, resulting in approximately $206.6 million of net proceeds. Also on June 24, 2008, we sold 278,000 common units to Atlas Pipeline Holdings, L.P., the parent of our general partner (NYSE: AHD AHD), and 1,112,000 common units to Atlas America, the parent of AHD s general partner, in a private placement at a net price of $36.02, resulting in approximately $50.1 million of net proceeds. In addition, we received approximately $5.4 million from our general partner to maintain its aggregate 2% general partner interest in us.

The net proceeds from the public and private placement offerings of our common units were utilized to fund the early termination of a majority of our crude oil derivative contracts that we entered into as proxy hedges for the prices we receive for the ethane and propane portion of our NGL equity volume. These hedges, which related to production periods ranging from the end of second quarter of 2008 through the fourth quarter of 2009, were put in place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 (see Recent Acquisition) and have become less effective as a result of significant increases in the price of crude oil and less significant increases in the price of ethane and propane. We estimate that we incurred a charge during the second quarter 2008 of approximately $10.6 million due to the decline in the price correlation of crude oil and ethane and propane. We terminated these derivative contracts during June and July 2008 at an aggregate net cost of approximately $264.0 million. Our net loss for the second quarter 2008 includes a $116.1 million cash derivative expense resulting from the June 2008 net payments of $170.4 million to unwind a portion of these derivative contracts. We also made payments of $93.6 million during July 2008 to unwind the remaining portion of these derivative contracts and will reflect a charge against our net income for a portion of this amount during the third quarter of 2008.

On June 27, 2008, we issued $250.0 million of 10-year, 8.75% senior unsecured notes (the 8.75% Notes) in a private placement transaction. The sale of the 8.75% Senior Notes generated net proceeds of approximately $244.9 million, which was utilized to repay indebtedness under our senior secured term loan and revolving credit facility.

On June 27, 2008, we obtained $80.0 million of increased commitments to our senior secured revolving credit facility, increasing our aggregate lender commitments to $380.0 million. In connection with this and the previously mentioned transactions, we also amended our senior secured credit facility to, among other things, exclude from the calculation of Consolidated EBITDA the costs associated with the termination of hedging agreements to the extent such costs are financed with or paid out of the net proceeds of an equity offering. In addition, consistent with several other recent energy master limited partnership agreements, our general partner s managing board and conflicts committee approved an amendment to our limited partnership agreement which will allow the cash expenditure to terminate derivative contracts to not reduce distributable cash flow.

Acquisitions

From the date of our initial public offering in January 2000 through June 2008, we have completed seven acquisitions at an aggregate cost of approximately $2.4 billion. Most recently, in July 2007, we acquired control of Anadarko Petroleum Corporation s (Anadarko NYSE: APC) 100% interest in the Chaney Dell natural gas gathering system and processing plants located in Oklahoma and its 72.8% undivided joint venture interest in the Midkiff/Benedum natural gas gathering system and processing plants located in Texas (the Anadarko Assets). The Chaney Dell system includes 3,470 miles of gathering pipeline and three processing plants, while the Midkiff/Benedum system includes 2,500 miles of gathering pipeline and two processing plants. The transaction was effected by the formation of two joint venture companies which own the respective systems, to which we contributed $1.9 billion and Anadarko contributed the Anadarko Assets.

We funded the purchase price, in part, from our private placement of $1.125 billion of our common units to investors at a negotiated purchase price of $44.00 per unit. Of the $1.125 billion, $168.8 million of these units were purchased by Atlas Pipeline Holdings, the parent of our general partner. Our general partner, which holds all of our incentive distribution rights, has also agreed to allocate up to $5.0 million of its incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter. Our general partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the general partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter (see Partnership Distributions). We funded the remaining purchase price from $830.0 million of proceeds from a senior secured term loan which matures in July 2014 and borrowings under our senior secured revolving credit facility that matures in July 2013 (see Term Loan and Credit Facility).

In connection with this acquisition, we reached an agreement with Pioneer Natural Resources Company (Pioneer NYSE: PXD), which currently holds an approximate 27.2% undivided joint venture interest in the Midkiff/Benedum system, whereby Pioneer has an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system, which began on June 15, 2008 and ends on November 1, 2008, and up to an additional 7.4% interest beginning on June 15, 2009 and ending on November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009). If the option is fully exercised, Pioneer would increase its interest in the system to approximately 49.2%. Pioneer would pay approximately $230 million, subject to certain adjustments, for the additional 22% interest if fully exercised. We will manage and control the Midkiff/Benedum system regardless of whether Pioneer exercised the purchase options. As of August 8, 2008, we have received no indication that Pioneer will exercise either of its options under the agreement.

Contractual Revenue Arrangements

Our principal revenue is generated from the transportation and sale of natural gas and NGLs. Variables that affect our revenue are:

- the volumes of natural gas we gather, transport and process 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 we receive 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.

In our Appalachian region, substantially all of the natural gas we transport is for Atlas Energy under percentage-of-proceeds (POP) contracts, as described below, in which we earn a fee equal to a percentage, generally 16%, of the gross sales price for natural gas subject, in most cases, to a minimum of $0.35 or $0.40 per thousand cubic feet, or mcf, depending on the ownership of the well. Since our inception in January 2000, our Appalachian system transportation fee has exceeded this minimum generally. The balance of the Appalachian system natural gas we transport is for third-party operators generally under fixed-fee contracts.

Our Mid-Continent segment revenue consists of the fees earned from our transmission, gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems, and then sell the natural gas, or produced NGLs, if any, off of delivery points on our systems. Under other agreements, we transport natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with our FERC-regulated transmission pipeline is comprised of firm transportation rates and, to the extent capacity is available following the reservation of firm system capacity, interruptible transportation rates and is recognized at the time transportation service is provided. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas. In connection with our gathering and processing operations, we enter into the following types of contractual relationships with our producers and shippers:

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

POP Contracts. These contracts provide for us to retain a negotiated percentage of the sale proceeds from residue natural gas and NGLs we gather and process, 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 market value.

Keep-Whole Contracts. These contracts require us, as the processor, to purchase raw natural gas from the producer at current market rates. Therefore, we bear the economic risk (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 we paid for the unprocessed natural gas. However, because the natural gas purchases contracted under keep-whole agreements are generally low in liquids content and meet downstream pipeline specifications without being processed, the natural gas can be bypassed around the processing plants on these systems and delivered directly into downstream pipelines during periods of margin risk. Therefore, the processing margin risk associated with a portion of our keep-whole contracts is minimized.

Recent Trends and Uncertainties

The midstream natural gas industry links the exploration and production of natural gas and the delivery of its components to end-use markets and provides natural gas gathering, compression, dehydration, treating, conditioning, processing, fractionation and transportation services. This industry group is generally characterized by regional competition based on the proximity of gathering systems and processing plants to natural gas producing wells.

We face competition for natural gas transportation and in obtaining natural gas supplies for our processing and related services operations. Competition for natural gas supplies is based primarily on the location of gas-gathering facilities and gas-processing plants, operating efficiency and reliability, and the ability to obtain a satisfactory price for products recovered. Competition for customers is based primarily on price, delivery capabilities, flexibility, and maintenance of high-quality customer relationships. Many of our competitors operate as master limited partnerships and enjoy a cost of capital comparable to and, in some cases lower than, ours. Other competitors, such as major oil and gas and pipeline companies, have capital resources and control supplies of natural gas substantially greater than ours. Smaller local distributors may enjoy a marketing advantage in their immediate service areas. We believe the primary difference between us and some of our competitors is that we provide an integrated and responsive package of midstream services, while some of our competitors provide only certain services. We believe that offering an integrated package of services, while remaining flexible in the types of contractual arrangements that we offer producers, allows us to compete more effectively for new natural gas supplies in our regions of operations.

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 recent years, mainly due to recent significant increases in natural gas prices, which could result in sustained increases in drilling activity during the current and future periods. 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.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with 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. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $1.72, $12.96 and $137.82 for NGLs, natural gas and condensate, respectively, would result in a change to our gross margin for the twelve-month period ending June 30, 2009 of approximately $28.9 million.

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Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
Operating data[1]:				
Appalachia:				
Average throughput volume mcfd	84,475	66,152	80,054	64,352
Mid-Continent:				
Velma system:				
Gathered gas volume mcfd	65,519	62,788	63,960	61,907
Processed gas volume mcfd	62,148	61,150	61,008	59,836
Residue gas volume mcfd	49,033	47,229	48,086	46,463
NGL volume bpd	6,993	6,697	6,841	6,473
Condensate volume bpd	296	212	277	206
Elk City/Sweetwater system:				
Gathered gas volume mcfd	292,544	308,703	298,961	298,355
Processed gas volume mcfd	229,673	234,896	233,038	221,151
Residue gas volume mcfd	207,859	215,501	210,495	203,288
NGL volume bpd	10,452	9,742	10,565	9,132
Condensate volume bpd	284	220	324	270
Chaney Dell system[2]:				
Gathered gas volume mcfd	284,528		268,008	
Processed gas volume mcfd	256,835		252,348	
Residue gas volume mcfd	243,465		231,830	
NGL volume bpd	13,358		12,880	
Condensate volume bpd	855		781	
Midkiff/Benedum system[2]:				
Gathered gas volume mcfd	150,157		146,350	
Processed gas volume mcfd	141,240		138,947	
Residue gas volume mcfd	96,160		96,386	
NGL volume bpd	20,830		20,590	
Condensate volume bpd	1,567		1,144	
NOARK system:				
Average Ozark Gas Transmission throughput volume mcfd	401,539	321,717	395,916	304,400

(1) Mcf represents thousand cubic feet; Mcfd represents thousand cubic feet per day; Bpd represents barrels per day.
(2) The Chaney Dell and Midkiff/Benedum systems were acquired on July 27, 2007.

Three Months Ended June 30, 2008 Compared to Three Months Ended June 30, 2007

Revenue. Natural gas and liquids revenue was $439.3 million for the three months ended June 30, 2008, an increase of $334.5 million from $104.8 million for the three months ended June 30, 2007. The increase was primarily attributable to revenue contribution from the Chaney Dell and Midkiff/Benedum systems, which we acquired in July 2007, of $281.3 million and an increase of $23.4 million from the Velma system due primarily to an increase in volumes and higher commodity prices and a $25.9 million increase from the Elk City/Sweetwater system due primarily to higher commodity prices, partially offset by a decrease in volumes. Processed natural gas volume on the Chaney Dell system was 256.8 MMcfd for the three months ended June 30, 2008, while the Midkiff/

Benedum system had processed natural gas volume of 141.2 MMcfd for the same period. Processed natural gas volume averaged 62.1 MMcfd on the Velma system for the three months ended June 30, 2008, an increase of 1.6% from the comparable prior year period. Processed natural gas volume on the Elk City/Sweetwater system averaged 229.7 MMcfd for the three months ended June 30, 2008, a decrease of 2.2% from the comparable prior year period. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected cash flows attributable to changes in market prices. See further discussion of the derivatives under Note 9 under Item 1, Financial Statements .

Transportation, compression and other fee revenue increased to $24.1 million for the three months ended June 30, 2008 compared with $19.0 million for the prior year comparable period. This $5.1 million increase was primarily due to $2.7 million of contributions from the Chaney Dell and Midkiff/Benedum systems and a $3.3 million increase from the Appalachia system. The Appalachia system s average throughput volume was 84.5 MMcfd for the three months ended June 30, 2008 as compared with 66.2 MMcfd for the three months ended June 30, 2007, an increase of 18.3 MMcfd or 27.7%. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system, the acquisition of the McKean processing plant and gathering system in central Pennsylvania for $6.1 million in August 2007, and the acquisition of the Vinland processing plant and gathering system in northeastern Tennessee for $9.1 million in February 2008. For the NOARK system, average Ozark Gas Transmission volume was 401.5 MMcfd for the three months ended June 30, 2008, an increase of 24.8% from the prior year comparable period, due to an increase in throughput capacity to 400.0 MMcfd during the third quarter of 2007 and higher customer demand.

Other loss, net, including the impact of certain gains and losses recognized on derivatives, was $314.3 million for the three months ended June 30, 2008, an unfavorable movement of $285.9 million from the prior year comparable period. This unfavorable movement was due primarily to an increase in non-cash derivative losses of $152.6 million, a $115.8 million net cash derivative expense related to the early termination of a portion of our crude oil derivative contracts (see Recent Events), and $22.4 million of non-qualified derivative cash settlements. The $152.6 million increase in non-cash derivative expense was due to an increase in forward crude oil market prices from March 31, 2008 to June 30, 2008 and their unfavorable mark-to-market impact on certain non-qualified derivative contracts we have for production volumes in future periods. Average forward crude oil market prices, which are the basis for adjusting the fair value of our crude oil derivative contracts, at June 30, 2008 were $140.26 per barrel, an increase of $43.32 from average forward crude oil market prices at March 31, 2008 of $96.94 per barrel. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Note 9 under Item 1, Financial Statements .

Costs and Expenses. Natural gas and liquids cost of goods sold of $350.0 million and plant operating expenses of $14.8 million for the three months ended June 30, 2008 represent increases of $262.9 million and $10.3 million, respectively, from the comparable prior year amounts due primarily to the contribution from the Chaney Dell and Midkiff/Benedum acquisition, higher commodity prices and an increase in production volume on the Velma system. Transportation and compression expenses increased $1.1 million to $4.3 million for the three months ended June 30, 2008 due principally to an increase of $1.2 million in Appalachia system operating and maintenance costs as a result of increased capacity, additional well connections and operating costs of the McKean processing plant and gathering system acquired in August 2007 and the Vinland processing plant and gathering system acquired in February 2008.

General and administrative expenses, including amounts reimbursed to affiliates, increased $2.6 million to $10.0 million for the three months ended June 30, 2008 compared with $7.4 million for the prior year comparable period. This increase was primarily related to higher costs of managing our operations, including the Chaney Dell and Midkiff/Benedum systems acquired in July 2007 and acquisition and capital raising opportunities, partially offset by a $1.3 million decrease in non-cash compensation expense. The decrease in non-cash compensation expense was principally attributable to a mark-to-market gain recognized for certain common unit

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awards for which the ultimate amount to be issued will be determined after the completion of our 2008 fiscal year. The mark-to-market gain was the result of a change in our common unit market price at June 30, 2008 when compared with the March 31, 2008 price, which is utilized in the estimate of the non-cash compensation expense for these awards.

Depreciation and amortization increased to $26.2 million for the three months ended June 30, 2008 compared with $6.7 million for the three months ended June 30, 2007 due primarily to the depreciation associated with our Chaney Dell and Midkiff/Benedum acquired assets, our expansion capital expenditures incurred subsequent to June 30, 2007 and a $4.0 million write-off of costs related to a pipeline expansion project. The costs incurred consisted of a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

Interest expense increased to $19.4 million for the three months ended June 30, 2008 as compared with $7.3 million for the comparable prior year period. This $12.1 million increase was primarily due to $11.3 million of interest associated with the term loan issued in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems (see Term Loan and Credit Facility) and a $1.4 million increase in the amortization of deferred finance costs principally due to $1.2 million of accelerated amortization associated with the retirement of a portion of our term loan with a portion of the net proceeds from our issuance of senior notes in June 2008 (see Recent Events).

Minority interest expense of $3.1 million for the three months ended June 30, 2008 represents Anadarko s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to effect our acquisition of control of the respective systems.

Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Revenue. Natural gas and liquids revenue was $805.4 million for the six months ended June 30, 2008, an increase of $598.4 million from $207.0 million for the six months ended June 30, 2007. The increase was primarily attributable to revenue contribution from the Chaney Dell and Midkiff/Benedum systems, which we acquired in July 2007, of $504.5 million and an increase from the Velma and Elk City/Sweetwater systems due primarily to an increase in volumes and higher commodity prices. Processed natural gas volume on the Chaney Dell system was 252.3 MMcfd for the six months ended June 30, 2008, while the Midkiff/Benedum system had processed natural gas volume of 138.9 MMcfd for the same period. Processed natural gas volume averaged 61.0 MMcfd on the Velma system for the six months ended June 30, 2008, an increase of 2.0% from the comparable prior year period. Processed natural gas volume on the Elk City/Sweetwater system averaged 233.0 MMcfd for the six months ended June 30, 2008, an increase of 5.4% from the comparable prior year period. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected cash flows attributable to changes in market prices. See further discussion of the derivatives under Note 9 under Item 1, Financial Statements .

Transportation, compression and other fee revenue increased to $48.2 million for the six months ended June 30, 2008 compared with $36.6 million for the prior year comparable period. This $11.6 million increase was primarily due to $5.1 million of contributions from the Chaney Dell and Midkiff/Benedum systems and a $4.9 million increase from the Appalachia system. The Appalachia system s average throughput volume was 80.1 MMcfd for the six months ended June 30, 2008 as compared with 64.4 MMcfd for the six months ended June 30, 2007, an increase of 15.7 MMcfd or 24.4%. The increase in the Appalachia system average daily throughput volume was principally due to new wells connected to our gathering system, the acquisition of the McKean processing plant and gathering system in central Pennsylvania in August 2007, and the acquisition of the Vinland processing plant and gathering system in northeastern Tennessee in February 2008. For the NOARK system, average Ozark Gas Transmission volume was 395.9 MMcfd for the six months ended June 30, 2008, an increase of 91.5 MMcfd or 30.1% from the prior year comparable period due to an increase in throughput capacity to 400.0 MMcfd during the third quarter 2007 and higher customer demand.

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Other loss, net, including the impact of certain gains and losses recognized on derivatives, was $401.0 million for the six months ended June 30, 2008, an unfavorable movement of $370.4 million from the prior year comparable period. This unfavorable movement was due primarily to an increase in non-cash derivative losses of $227.1 million, a $115.8 million net cash derivative expense related to the early termination of a portion of our crude oil derivative contracts (see Recent Events), and $34.3 million of non-qualified derivative cash settlements. The $227.1 million increase in non-cash derivative expense was due to an increase in forward crude oil market prices from December 31, 2007 to June 30, 2008 and their unfavorable mark-to-market impact on certain non-qualified derivative contracts we have for production volumes in future periods. Average forward crude oil market prices, which are the basis for adjusting the fair value of our crude oil derivative contracts, at June 30, 2008 were $140.26 per barrel, an increase of $50.37 from average forward crude oil market prices at December 31, 2007 of $89.89 per barrel. We enter into derivative instruments principally to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. See further discussion of derivatives under Note 9 under Item 1, Financial Statements .

Costs and Expenses. Natural gas and liquids cost of goods sold of $626.6 million and plant operating expenses of $29.8 million for the six months ended June 30, 2008 represented increases of $451.7 million and $20.7 million, respectively, from the comparable prior year amounts due primarily to the contribution from the Chaney Dell and Midkiff/Benedum acquisition, higher commodity prices and an increase in production volume on the Velma and Elk City/Sweetwater systems. Transportation and compression expenses increased $1.8 million to $8.1 million for the six months ended June 30, 2008 due to an increase of $2.1 million in Appalachia system operating and maintenance costs as a result of increased capacity, additional well connections and operating costs of the McKean processing plant and gathering system acquired in August 2007 and the Vinland processing plant and gathering system acquired in February 2008.

General and administrative expenses, including amounts reimbursed to affiliates, increased $1.8 million to $15.5 million for the six months ended June 30, 2008 compared with $13.7 million for the prior year comparable period. This increase was primarily related to higher costs of managing our operations, including the Chaney Dell and Midkiff/Benedum systems acquired in July 2007 and acquisition and capital raising activities, partially offset by a $5.9 million decrease in non-cash compensation expense. The decrease in non-cash compensation expense was principally attributable to a mark-to-market gain recognized for certain common unit awards for which the ultimate amount to be issued will be determined after the completion of our 2008 fiscal year. The mark-to-market gain was the result of a change in our common unit market price at June 30, 2008 when compared with the December 31, 2007 price, which is utilized in the estimate of the non-cash compensation expense for these awards.

Depreciation and amortization increased to $52.0 million for the six months ended June 30, 2008 compared with $13.2 million for the six months ended June 30, 2007 due primarily to the depreciation associated with our Chaney Dell and Midkiff/Benedum acquired assets, our expansion capital expenditures incurred subsequent to June 30, 2007 and an $8.0 million write-off of costs related to a pipeline expansion project. The costs incurred consisted of a vendor deposit for the manufacture of pipeline which expired in accordance with a contractual arrangement.

Interest expense increased to $39.8 million for the six months ended June 30, 2008 as compared with $14.1 million for the comparable prior year period. This $25.7 million increase was primarily due to $24.9 million of interest associated with the term loan issued in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems (see Term Loan and Credit Facility) and a $1.5 million increase in the amortization of deferred finance costs principally due to $1.2 million of accelerated amortization associated with the retirement of a portion of our term loan with a portion of the net proceeds from our issuance of senior notes in June 2008 (see Recent Events).

Minority interest expense of $5.2 million for the six months ended June 30, 2008 represents Anadarko s 5% interest in the net income of the Chaney Dell and Midkiff/Benedum joint ventures, which were formed to effect our acquisition of control of the respective systems.

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Liquidity and Capital Resources

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 common unitholders and general partner. In general, we expect to fund:

- 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 limited partner units.

We had $20.0 million outstanding under our $380.0 million senior secured credit facility at June 30, 2008 and $22.0 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheet, with $338.0 million of remaining committed capacity under the credit facility, subject to covenant limitations (see Term Loan and Credit Facility). In addition to the availability under the credit facility, we have a universal shelf registration statement on file with the Securities and Exchange Commission, which allows us to issue equity or debt securities (see Shelf Registration Statement), of which $136.4 million remains available at June 30, 2008. At June 30, 2008, we had a working capital deficit of $120.3 million compared with a $78.2 million working capital deficit at December 31, 2007. This decrease in working capital was primarily due to $52.9 million increase in the current portion of our hedge liability and a $135.8 million increase in our accounts payable due primarily to a $94.0 million payable to our hedge counterparties related to the early termination of certain crude oil derivative instruments (see Recent Events), partially offset by a $149.4 million increase in cash and cash equivalents. We believe that we have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, unitholder distributions, contingencies and anticipated capital expenditures. However, we are subject to business and operational risks that could adversely affect our cashflow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings and the issuance of additional limited partner units.

Cash Flows Six Months Ended June 30, 2008 Compared to Six Months Ended June 30, 2007

Net cash provided by operating activities of $66.2 million for the six months ended June 30, 2008 represented an increase of $27.7 million from $38.5 million for the comparable prior year period. The increase was derived principally from a $128.2 million increase in cash flows from working capital changes, partially offset by a $95.4 million decrease in net income excluding non-cash charges. The increase in working capital changes was primarily due to the favorable timing of cash payments for the current portion of hedge liabilities and accounts payable to our derivative counterparties. The decrease in net income excluding non-cash charges was principally due to the $116.1 million cash impact from the early termination of certain crude oil derivative instruments during June 2008 (see Recent Events), partially offset by contributions from the Chaney Dell and Midkiff/Benedum systems, which were acquired in July 2007. The non-cash charges which impacted net income include a $171.0 million increase in non-cash derivative losses, and a $38.8 million increase in depreciation and amortization, partially offset by a $5.9 million decrease in non-cash compensation expense. The movement in non-cash derivative losses resulted from increases in commodity prices during the six months ended June 30, 2008 and their unfavorable impact on the fair value of derivative contracts we have for future periods. The increase in depreciation and amortization resulted from our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007. The decrease in non-cash compensation expense was principally attributable to a mark-to-market gain recognized during the six months ended June 30, 2008 for certain common unit awards for which the ultimate amount to be issued will be determined after the completion of our 2008 fiscal year. The mark-to-market gain was the result of a decrease in our common unit market price at June 30, 2008 when compared with the December 31, 2007 price, which is utilized in the estimate of the non-cash compensation expense for these awards.

Net cash used in investing activities was $125.4 million for the six months ended June 30, 2008, an increase of $83.7 million from $41.7 million for the comparable prior year period. This increase was principally due to a $115.4 million increase in capital expenditures, partially offset by a $30.2 million cash reimbursement for state sales tax initially paid on our prior year transaction to acquire the Chaney Dell and Midkiff/Benedum systems and an additional cash receipt of $1.2 million for post-closing purchase price adjustments for this acquisition. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities was $208.7 million for the six months ended June 30, 2008, an increase of $204.9 million from $3.8 million for the comparable prior year period. This increase was principally due to $257.2 million of net proceeds from the issuance of our common units during June 2008 and $244.9 million of net proceeds from the issuance of 8.75% Senior Notes during June 2008 (see Recent Events). This amount was partially offset by a $122.8 million repayment of the outstanding principal balance on our term loan, a $121.0 million net decrease in borrowings under our revolving credit facility and a $54.7 million increase in cash distributions to common limited partners and our general partner.

Capital Requirements

Our operations require continual investment to upgrade or enhance existing operations and to ensure compliance with safety, operational, and environmental regulations. Our capital requirements 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 and to expand the capacity of our existing operations.

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,	
	2008	2007	2008	2007
Maintenance capital expenditures	$ 2,045	$ 700	$ 3,664	$ 1,472
Expansion capital expenditures	71,156	24,552	153,606	40,409
Total	$ 73,201	$ 25,252	$ 157,270	$ 41,881

Expansion capital expenditures increased to $71.2 million and $153.6 million for the three and six months ended June 30, 2008, respectively, due principally to the construction of a 60 MMcfd expansion of our Sweetwater processing plant and the acquisition of a gathering system located in Tennessee with an approximate capacity of 20.0 MMcfd for $9.1 million. The increase in expansion capital expenditures also includes expansions of our existing gathering systems and upgrades to processing facilities and compressors to accommodate new wells drilled in our service areas. Maintenance capital expenditures for the three and six months ended June 30, 2008 increased to $2.0 million and $3.7 million, respectively, compared with the comparable prior year periods due to the maintenance capital requirements of the Chaney Dell and Midkiff/Benedum systems, which were acquired in July 2007, and fluctuations in the timing of our scheduled maintenance activity. As of June 30, 2008, we are committed to expend approximately $158.6 million on pipeline extensions, compressor station upgrades and processing facility upgrades.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and our general partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

Our general partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, rate refunds and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When our general partner determines our quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Available cash is initially distributed 98% to our common limited partners and 2% to our general partner. These distribution percentages are modified to provide for incentive distributions to be paid to our general partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our general partner that are in excess of 2% of the aggregate amount of cash being distributed. During July 2007, our general partner, holder of all of our incentive distribution rights, agreed to allocate up to $5.0 million of incentive distribution rights per quarter back to us through the quarter ended June 30, 2009, and up to $3.75 million per quarter thereafter in connection with our acquisition of the Chaney Dell and Midkiff/Benedum systems (see Acquisitions). Our general partner also agreed that the resulting allocation of incentive distribution rights back to us would be after the general partner receives the initial $3.7 million per quarter of incentive distribution rights through the quarter ended December 31, 2007, and $7.0 million per quarter thereafter. Of the $24.0 million of incentive distributions declared for the six months ended June 30, 2008, the general partner received $15.2 million after the allocation of $8.8 million of its incentive distribution rights back to us.

Common Equity Offerings

On June 24, 2008, we sold 5,750,000 common units in a public offering at a price of $37.52 per unit, yielding net proceeds of approximately $206.6 million. Also on June 24, 2008, we sold 1,112,000 common units to Atlas America and 278,000 common units to AHD in a private placement at a net price of $36.02 per unit, resulting in net proceeds of approximately $50.1 million. We also received a capital contribution from AHD of $5.4 million for AHD to maintain its 2.0% general partner interest in us. We utilized the net proceeds from both sales and the capital contribution to fund the early termination of certain derivative agreements (see Recent Events).

In July 2007, we sold 25,568,175 common units through a private placement to investors at a negotiated purchase price of $44.00 per unit, yielding net proceeds of approximately $1.125 billion. Of the 25,568,175 common units sold, 3,835,227 common units were purchased by AHD for $168.8 million. We also received a capital contribution from AHD of $23.1 million in order for AHD to maintain its 2.0% general partner interest in us. We utilized the net proceeds from the sale to partially fund the Chaney Dell and Midkiff/Benedum acquisitions (see Acquisitions).

Shelf Registration Statement

We have an effective shelf registration statement with the Securities and Exchange Commission that permits us to periodically issue equity and debt securities for a total value of up to $500 million. As of June 30, 2008, $136.4 million remains available for issuance under the shelf registration statement. However, the amount, type and timing of any offerings will depend upon, among other things, our funding requirements, prevailing market conditions, and compliance with our credit facility covenants.

Private Placement of Convertible Preferred Units

On March 13, 2006, we entered into an agreement to sell 30,000 6.5% cumulative convertible preferred units representing limited partner interests to Sunlight Capital Partners, LLC (Sunlight Capital), an affiliate of Elliott & Associates, for aggregate gross proceeds of $30.0 million. We also sold an additional 10,000 6.5% cumulative preferred units to Sunlight Capital for $10.0 million on May 19, 2006, pursuant to our right under the agreement to require Sunlight Capital to purchase such additional units. The preferred units were originally entitled to receive dividends of 6.5% per annum commencing on March 13, 2007 and were to have been accrued and paid quarterly on the same date as the distribution payment date for our common units. In April 2007, we and Sunlight Capital agreed to amend the terms of the preferred units effective as of that date. The terms of the preferred units were amended to entitle them to receive dividends of 6.5% per annum commencing on March 13, 2008 and to be convertible, at Sunlight Capital s option, into common units commencing on the date immediately following the first record date for common unit distributions after March 13, 2008 at a conversion price equal to the lesser of $43.00 or 95% of the market price of our common units as of the date of the notice of conversion. We may elect to pay cash rather than issue common units in satisfaction of a conversion request. We have the right to call the preferred units at a specified premium. The applicable redemption price under the amended agreement was increased to $53.22. If not converted into common units or redeemed prior to May 2010, the preferred units will automatically be converted into our common units in accordance with the agreement. In consideration of Sunlight Capital s consent to the amendment of the preferred units, we issued $8.5 million of our 8.125% senior unsecured notes due 2015 (see Note 4 under Item 1, Financial Statements) to Sunlight Capital. We recorded the senior unsecured notes issued as long-term debt and a preferred unit dividend within partners capital on our consolidated balance sheet and, during the three months ended June 30, 2007, reduced net income (loss) attributable to common limited partners and the general partner by $3.8 million of this amount, which was the portion deemed to be attributable to the concessions of the common limited partners and the general partner to the preferred unitholder, on our consolidated statements of operations.

Sunlight Capital is entitled to receive the dividends on the preferred units pro rata from the March 13, 2008 commencement date. Dividends previously paid and those to be paid on the preferred units and the premium paid upon their redemption, if any, will be recognized as a reduction to our net income (loss) in determining net income (loss) attributable to common unitholders and the general partner. If converted to common units, the preferred equity amount converted will be reclassified to common unit equity within partners capital on our consolidated balance sheet.

Term Loan and Credit Facility

At June 30, 2008, we have a senior secured credit facility with a syndicate of banks which consists of a term loan which matures in July 2014 and a $380.0 million revolving credit facility which matures in July 2013. Borrowings under the credit facility bear interest, at our 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 revolving credit facility borrowings at June 30, 2008 was 4.4%, and the weighted average interest rate on the outstanding term loan borrowings at June 30, 2008 was 5.2%. Up to $50.0 million of the credit facility may be utilized for letters of credit, of which $22.0 million was outstanding at June 30, 2008. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheet.

On June 12, 2008, we entered into an amendment to our revolving credit facility and term loan agreement to revise the definition of Consolidated EBITDA to provide for the add-back of charges relating to our early termination of certain crude oil derivative contracts (see Recent Events) in calculating our Consolidated EBITDA. Pursuant to this amendment, on June 27, 2008, we repaid $122.8 million of our outstanding term loan and repaid $120.0 million of outstanding borrowings under the credit facility with proceeds from our issuance of $250.0 million of 10-year, 8.75% senior unsecured notes (see Senior Notes). Additionally, pursuant to this amendment, on June 27, 2008 our lenders increased their commitments for our revolving credit facility by $80.0 million to $380.0 million.

Borrowings under the credit facility are secured by a lien on and security interest in all of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum joint ventures, and by the guaranty of each of its consolidated subsidiaries other than the joint venture companies. 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 our 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. We are in compliance with these covenants as of June 30, 2008. Mandatory prepayments of the amounts borrowed under the term loan portion of the credit facility are required from the net cash proceeds of debt issuances, and of dispositions of assets that exceed $50.0 million in the aggregate in any fiscal year that are not reinvested in replacement assets within 360 days. In connection with the new credit facility, we agreed to remit an underwriting fee to the lead underwriting bank of the credit facility of 0.75% of the aggregate principal amount of the term loan outstanding on January 23, 2008. In January 2008, we and the underwriting bank agreed to extend the agreement through June 30, 2008. In June 2008, we and the underwriting bank agreed to extend the agreement through November 30, 2008 and amend the underwriting fee to be 0.50% of the aggregate principal amount of the term loan outstanding as of that date.

The events which constitute an event of default for our credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreements, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. The credit facility requires us to maintain a ratio of funded debt (as defined in the credit facility) to EBITDA (as defined in the credit facility) ratio of not more than 5.25 to 1.0, and an interest coverage ratio (as defined in the credit facility) of not less than 2.5 to 1.0, increasing to 2.75 to 1.0 commencing September 30, 2008. During a Specified Acquisition Period (as defined in the credit facility), for the first 2 full fiscal quarters subsequent to the closing of an acquisition with total consideration in excess of $75.0 million, the ratio of funded debt to EBITDA will be permitted to step up to 5.75 to 1.0. As of June 30, 2008, our ratio of funded debt to EBITDA was 4.6 to 1.0 and our interest coverage ratio was 3.5 to 1.0.

We are unable to borrow under our credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

Senior Notes

At June 30, 2008, we had $250.0 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $293.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with $0.8 million of unamortized premium received as of June 30, 2008. The 8.75% Senior Notes were issued on June 27, 2008 in a private placement transaction pursuant to Rule 144A and Regulation S under the Securities Act of 1933 for net proceeds of $244.9 million, after underwriting commissions and other transaction costs. Interest on the Senior Notes in the aggregate is payable semi-annually in arrears on June 15 and December 15. The Senior Notes are redeemable at any time at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. A similar redemption option exists prior to December 15, 2008 with respect to the 8.125% Senior Notes. The Senior Notes in the aggregate are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our Credit Facility.

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Indentures governing the Senior Notes in the aggregate contain covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. We are in compliance with these covenants as of June 30, 2008.

In connection with the issuance of the 8.75% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission for the 8.75% Senior Notes, (b) cause the exchange offer registration statement to be declared effective by the Securities and Exchange Commission, and (c) cause the exchange offer to be consummated by February 23, 2009. If we do not meet the aforementioned deadline, the 8.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that we have caused the exchange offer to be consummated.

Off Balance Sheet Arrangements

As of June 30, 2008, our off balance sheet arrangements are limited to our letters of credit outstanding of $22.0 million and our commitments to expend approximately $158.6 million on capital projects.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making 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 revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depreciation and amortization, asset impairment, fair value of derivative instruments, stock compensation, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. 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, 2007, and there have been no material changes to these policies through June 30, 2008.

Fair Value of Financial Instruments

We adopted the provisions of SFAS No. 157 at January 1, 2008. SFAS No. 157 establishes a fair value hierarchy which requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. SFAS No. 157 (1) creates a single definition of fair value, (2) establishes a hierarchy for measuring fair value, and (3) expands disclosure requirements about items measured at fair value. SFAS No. 157 does not change existing accounting rules governing what can or what must be recognized and reported at fair value in our financial statements, or disclosed at fair value in our notes to the financial statements. As a result, we will not be required to recognize any new assets or liabilities at fair value.

SFAS No. 157 s hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2   Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3   Unobservable inputs that reflect the entity s own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

We use the fair value methodology outlined in SFAS No. 157 to value the assets and liabilities for our respective outstanding derivative contracts (see Note 9). All of our derivative contracts are defined as Level 2, with the exception of our NGL fixed price swaps and crude oil options. Our Level 2 commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity. Our interest rate derivative contracts are valued using a LIBOR rate-based forward price curve model, and are therefore defined as Level 2. Valuations for our NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of natural gas, crude oil, and propane prices, and therefore are defined as Level 3. Valuations for our crude oil options (including those associated with NGL sales) are based on forward price curves developed by the related financial institution based upon current quoted prices for crude oil futures, and therefore are defined as Level 3.

Recently Adopted Accounting Standards

In February 2007, the Financial Accounting Standards Board (FASB) issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities including an amendment to FASB Statement No. 115 (SFAS No. 159). SFAS No. 159 permits entities to choose to measure eligible financial instruments and certain other items at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 is effective at the inception of an entity s first fiscal year beginning after November 15, 2007 and offers various options in electing to apply its provisions. We adopted SFAS No. 159 at January 1, 2008, and have elected not to apply the fair value option to any of our financial instruments.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements (SFAS No. 157). SFAS No. 157 defines fair value, establishes a framework for measuring fair value in accordance with generally accepted accounting principles and expands disclosures about fair value statements. In February 2008, the FASB issued FASB Staff Position SFAS No. 157-b, Effective Date of FASB Statement No. 157 , which provides for a one-year deferral of the effective date of SFAS No. 157 with regard to an entity s non-financial assets, non-financial liabilities or any non-recurring fair value measurement. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We adopted SFAS No. 157 at January 1, 2008 with respect to our derivative instruments, which are measured at fair value within our financial statements. The provisions of SFAS No. 157 have not been applied to our non-financial assets and non-financial liabilities. See Fair Value of Financial Instruments for disclosures pertaining to the provisions of SFAS No. 157 with regard to our financial instruments.

Recently Issued Accounting Standards

In June 2008, the FASB issued Staff Position No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities (FSP EITF 03-6-1). FSP EITF 03-6-1 applies to the calculation of earnings per share (EPS) described in paragraphs 60 and 61 of FASB Statement No. 128, Earnings per Share for share-based payment awards with rights to dividends or dividend equivalents. It states that unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of EPS pursuant to the two-class method. FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after

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December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. All prior-period EPS data presented shall be adjusted retrospectively to conform to the provisions of this FSP. We will apply the requirements of FSP EITF 03-6-1 upon its adoption on January 1, 2009 and we currently do not expect the adoption of FSP EITF 03-6-1 to have an impact on our financial position and results of operations.

In May 2008, the FASB issued SFAS No. 162, The Hierarchy of Generally Accepted Accounting Principles (SFAS No. 162). SFAS No. 162 identifies sources of accounting principles and the framework for selecting such principles used in the preparation of financial statements of nongovernmental entities presented in conformity with U.S. generally accepted accounting principles. SFAS No. 162 will be effective 60 days following the SEC s approval of AU Section 411, *The Meaning of* Present Fairly in Conformity with Generally Accepted Accounting Principles . We currently do not expect the adoption of SFAS No. 162 to have an impact on our financial position and results of operations.

In April 2008, the FASB issued Staff Position No. 142-3, Determination of Useful Life of Intangible Assets (FSP FAS 142-3). FSP FAS 142-3 amends the factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under FASB Statement No. 142, Goodwill and Other Intangible Assets (SFAS 142). The intent of this FSP is to improve the consistency between the useful life of a recognized intangible asset under SFAS 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No 141(R), Business Combinations (SFAS No. 141(R)), and other U.S. generally accepted accounting principles. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. The guidance for determining the useful life of a recognized intangible asset should be applied prospectively to intangible assets acquired after the effective date. The disclosure requirements should be applied prospectively to all intangible assets recognized as of, and subsequent to, the effective date. We will apply the requirements of FSP FAS 142-3 upon its adoption on January 1, 2009 and we currently do not expect the adoption of FSP FAS 142-3 to have a material impact on our financial position and results of operations.

In March 2008, the FASB ratified the Emerging Issues Task Force (EITF) consensus on EITF Issue No. 07-4, Application of the Two-Class Method under FASB Statement No. 128, Earnings per Share, to Master Limited Partnerships (EITF No. 07-4), an update of EITF No. 03-6, Participating Securities and the Two-Class Method Under FASB Statement No. 128 (EITF No. 03-6). EITF No. 07-4 requires the calculation of a Master Limited Partnership s net earnings per limited partner unit for each period presented according to distributions declared and participation rights in undistributed earnings as if all of the earnings for that period had been distributed. In periods with undistributed earnings above specified levels, the calculation per the two-class method results in an increased allocation of such undistributed earnings to the general partner and a dilution of earnings to the limited partners. EITF No. 07-4 is effective for fiscal years beginning after December 15, 2008, including interim periods within those fiscal years, and requires retrospective application of the guidance to all periods presented. Early adoption is prohibited. We do not believe the adoption of EITF No. 07-4 will have any impact on our financial position or results of operations. Our net earnings per limited partner unit calculated under the requirements of EITF No. 03-6 would not have differed under the requirements of EITF No. 07-4.

In March 2008, the FASB issued Statement of Financial Accounting Standards (SFAS) No. 161, Disclosures about Derivative Instruments and Hedging Activities an amendment of FASB Statement No. 133 (SFAS No. 161). SFAS No. 161 amends the requirements of SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities (SFAS No. 133) to require enhanced disclosure about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years beginning after November 15, 2008, with early adoption encouraged. We are currently evaluating the impact the adoption of SFAS No. 161 will have on the disclosures regarding our derivative instruments.

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In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements-an amendment of ARB No. 51 (SFAS No. 160). SFAS No. 160 amends ARB No. 51 to establish accounting and reporting standards for the noncontrolling interest (minority interest) in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a noncontrolling interest in a subsidiary is an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS No. 160 also requires consolidated net income to be reported, and disclosed on the face of the consolidated statement of operations, at amounts that include the amounts attributable to both the parent and the noncontrolling interest. Additionally, SFAS No. 160 establishes a single method for accounting for changes in a parent s ownership interest in a subsidiary that does not result in deconsolidation and that the parent recognize a gain or loss in net income when a subsidiary is deconsolidated. SFAS No. 160 is effective for fiscal years beginning on or after December 15, 2008. We will apply the requirements of SFAS No. 160 upon its adoption on January 1, 2009 and we are currently evaluating whether SFAS No. 160 will have an impact on our financial position and results of operations.

In December 2007, the FASB issued SFAS No 141(R), Business Combinations (SFAS No. 141(R)). SFAS No. 141(R) replaces SFAS No. 141, Business Combinations , however retains the fundamental requirements that the acquisition method of accounting be used for all business combinations and for an acquirer to be identified for each business combination. SFAS No. 141(R) requires an acquirer to recognize the assets acquired, liabilities assumed, and any noncontrolling interest in the acquiree at the acquisition date, at their fair values as of that date, with specified limited exceptions. Changes subsequent to that date are to be recognized in earnings, not goodwill. Additionally, SFAS No. 141 (R) requires costs incurred in connection with an acquisition be expensed as incurred. Restructuring costs, if any, are to be recognized separately from the acquisition. The acquirer in a business combination achieved in stages must also recognize the identifiable assets and liabilities, as well as the noncontrolling interests in the acquiree, at the full amounts of their fair values. SFAS No. 141(R) is effective for business combinations occurring in fiscal years beginning on or after December 15, 2008. We will apply the requirements of SFAS No. 141(R) upon its adoption on January 1, 2009 and we are currently evaluating whether SFAS No. 141(R) will have an impact on our financial position and results of operations.

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 natural gas prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable 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.

General

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 periodical 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, 2008. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

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Interest Rate Risk. At June 30, 2008, we had a $380.0 million senior secured revolving credit facility ($20.0 million outstanding). We also had $707.2 million outstanding under our senior secured term loan at June 30, 2008. The weighted average interest rate for the revolving credit facility borrowings was 4.4% at June 30, 2008, and the weighted average interest rate for the term loan borrowings was 5.2% at June 30, 2008.

At June 30, 2008, we have interest rate derivative contracts having aggregate notional principal amounts of $450.0 million. Under the terms of these agreements, we will pay weighted average interest rates of 3.02%, plus the applicable margin as defined under the terms of our revolving credit facility (see Term Loan and Credit Facility), and will receive LIBOR, plus the applicable margin, on the notional principal amounts. These derivatives effectively convert $450.0 million of our floating rate debt under the term loan and revolving credit facility to fixed-rate debt. The interest rate swap agreements are effective as of June 30, 2008 and expire during periods ranging from January 30, 2010 through April 30, 2010.

Holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by $2.8 million.

Commodity Price Risk. We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or 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. A 10% change in the average price of NGLs, natural gas and condensate we process and sell, based on estimated unhedged market prices of $1.72, $12.96 and $137.82 for NGLs, natural gas and condensate, respectively, would result in a change to our gross margin for the twelve-month period ending June 30, 2009 of approximately $28.9 million.

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price and interest rate risk management activities. We enter into financial swap and option 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. We also enter into financial swap instruments to hedge certain portions of our floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate is sold or interest payments on the underlying debt instrument is due. Under swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not obligation, to purchase or sell natural gas, NGLs and condensate at a fixed price for the relevant contract period. These financial swap and option instruments are generally classified as cash flow hedges in accordance with SFAS No. 133.

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 derivative contracts to the forecasted transactions. We assess, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. 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 adequate correlation between the hedging instrument and the underlying item being hedged, we will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by us through the utilization of market data, will be recognized immediately within other income (loss) in our consolidated statements of operations. For derivatives qualifying as hedges, we recognize the effective portion of changes in fair value in partners capital as accumulated other comprehensive income (loss), and reclassify the portion relating to commodity derivatives to natural gas and liquids revenue and the portion relating to interest rate derivatives to interest expense within our consolidated statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, we recognize changes in fair value within other income (loss) in our consolidated statements of operations as they occur.

During June 2008, we made net payments of $170.4 million related to the early termination of crude oil derivative contracts that were entered into as proxy hedges for the prices received on the ethane and propane portion of our NGL equity volume. These derivative contracts were put into place simultaneously with our acquisition of the Chaney Dell and Midkiff/Benedum systems in July 2007 and related to production periods ranging from the end of the second quarter of 2008 through the fourth quarter of 2009. During the three and six months ended June 30, 2008, we recognized a derivative expense of $162.1 million related to the termination of these derivative instruments, including a non-cash portion of $46.3 million, within other loss, net on our consolidated statements of operations. We also recognized a cash derivative expense of $0.3 million within natural gas and liquids revenue on our consolidated statements of operations. In addition, $54.3 million will be reclassified from accumulated other comprehensive loss within partner s capital on our consolidated balance sheet and recognized as non-cash derivative expenses during the period beginning on July 1, 2008 and ending on December 31, 2009, the period the derivatives were originally scheduled to be settled, as a result of the early termination of certain crude oil derivatives that were classified as cash flow hedges in accordance with SFAS No. 133 at the date of termination. During July 2008, we paid an additional $93.6 million related to the early termination of the crude oil derivative contracts that relate to production periods through the end of 2009 (see Recent Events).

In connection with the Chaney Dell and Midkiff/Benedum acquisition, we reached an agreement with Pioneer granting it an option to buy up to an additional 14.6% interest in the Midkiff/Benedum system, which began on June 15, 2008 and ends on November 1, 2008 and an additional 7.4% interest beginning on June 15, 2009 and ending on November 1, 2009 (the aggregate 22.0% additional interest can be entirely purchased during the period beginning June 15, 2009 and ending on November 1, 2009; see Note 8 under Item 1, Financial Statements). As of August 8, 2008, we have received no indication that Pioneer will exercise either of its options under the agreement. If Pioneer does exercise either of these options, we will discontinue hedge accounting for the derivative instruments covering the portion of the forecasted production of the Midkiff/Benedum system sold to Pioneer and we will evaluate these derivative instruments to determine if they can be documented to match other forecasted production we may have.

The following table summarizes our derivative activity for the periods indicated (amounts in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Loss from cash settlement of qualifying hedge instruments(1)	$ (33,152)	$ (7,650)	$ (50,795)	$ (10,697)
Gain/(loss) from change in market value of non-qualifying derivatives(2)	(136,736)	(18,835)	(207,932)	(20,137)
Gain/(loss) from change in market value of ineffective portion of qualifying derivatives(2)	1,934	(9,714)	(3,726)	(10,689)
Loss from cash settlement of non-qualifying derivatives(2)	(184,564)		(196,489)	
Loss from cash settlement of interest rate derivatives(3)	(194)		(194)	

(1) Included within natural gas and liquids revenue on our consolidated statements of operations.
(2) Included within other loss, net on our consolidated statements of operations.
(3) Included within interest expense on our consolidated statements of operations.

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As of June 30, 2008, we had the following interest rate and commodity derivatives, including derivatives that do not qualify for hedge accounting:

Interest Fixed Rate Swap

Term	Notional Amount		Type	Contract Period Ended December 31,	Fair Value Asset/(Liability)(1) (in thousands)
January 2008 - January 2010	$ 200,000,000	Pay 2.88%	Receive LIBOR	2008	$ (250)
				2009	977
				2010	170
					$ 897
April 2008 - April 2010	$ 250,000,000	Pay 3.14%	Receive LIBOR	2008	$ (635)
				2009	589
				2010	726
					$ 680

Natural Gas Liquids Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (gallons)	Average Fixed Price (per gallon)	Fair Value Liability(2) (in thousands)
2008	14,868,000	$ 0.697	$ (13,921)
2009	8,568,000	$ 0.746	(7,069)
			$ (20,990)

Crude Oil Sales Options (associated with NGL volume)

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset/(Liability)(3) (in thousands)	Option Type
2008	600,000	40,068,000	$ 60.00	$ 4	Puts purchased
2008	126,000	11,219,040	$ 127.55	(962)	Puts sold(4)
2008	126,000	11,219,040	$ 140.00	1,821	Calls purchased(4)
2008	946,800	51,529,968	$ 80.13	(57,308)	Calls sold
2009	1,056,000	94,026,240	$ 126.05	(11,425)	Puts sold(4)(5)
2009	1,056,000	94,026,240	$ 143.00	18,033	Calls purchased(4)(5)
2009	3,636,000	219,602,880	$ 79.51	(215,989)	Calls sold(5)
2010	3,127,500	202,370,490	$ 81.09	(176,190)	Calls sold
2011	606,000	32,578,560	$ 95.56	(26,751)	Calls sold
2012	450,000	24,192,000	$ 97.10	(18,820)	Calls sold

	$	(487,587)

Natural Gas Sales Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(6)	Average Fixed Price (per mmbtu) (6)	Fair Value Liability(3) (in thousands)
2008	2,742,000	$ 8.823	$ (12,942)
2009	5,724,000	$ 8.611	(22,102)
2010	4,560,000	$ 8.526	(12,744)
2011	2,160,000	$ 8.270	(5,423)
2012	1,560,000	$ 8.250	(3,888)
			$ (57,099)

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Natural Gas Basis Sales

Production Period Ended December 31,	Volumes (mmbtu)(6)		Average Fixed Price (per mmbtu)(6)		Fair Value Asset(3) (in thousands)
2008	2,742,000	$	(0.744)	$	2,605
2009	5,724,000	$	(0.558)		2,706
2010	4,560,000	$	(0.622)		1,048
2011	2,160,000	$	(0.664)		37
2012	1,560,000	$	(0.601)		27
				$	6,423

Natural Gas Purchases Fixed Price Swaps

Production Period Ended December 31,	Volumes (mmbtu)(6)		Average Fixed Price (per mmbtu)(6)		Fair Value Asset(3) (in thousands)
2008	8,130,000	$	9.001(7)	$	37,081
2009	15,564,000	$	8.680		59,019
2010	8,940,000	$	8.580		25,632
2011	2,160,000	$	8.270		5,423
2012	1,560,000	$	8.250		3,888
				$	131,043

Natural Gas Basis Purchases

Production Period Ended December 31,	Volumes (mmbtu)(6)		Average Fixed Price (per mmbtu)(6)		Fair Value Asset/(Liability)(3) (in thousands)
2008	8,130,000	$	(1.114)	$	(8,045)
2009	15,564,000	$	(0.654)		(9,633)
2010	8,940,000	$	(0.600)		(2,638)
2011	2,160,000	$	(0.700)		116
2012	1,560,000	$	(0.610)		58
				$	(20,142)

Crude Oil Sales

Production Period Ended December 31,	Volumes (barrels)		Average Fixed Price (per barrel)		Fair Value Liability(3) (in thousands)
2008	25,200	$	60.427	$	(2,031)
2009	33,000	$	62.700		(2,578)

	$ (4,609)

Crude Oil Participating Swaps for NGLs[8]

Production Period Ended December 31,	Crude Volume (barrels)	Associated NGL Volume (gallons)	Average Crude Strike Price (per barrel)	Fair Value Asset [3] (in thousands)	Option Type
2008	126,000	11,219,040	$ 137.00	$ 748	Participating swaps

Crude Oil Sales Options

Production Period Ended December 31,	Volumes (barrels)	Average Strike Price (per barrel)	Fair Value Liability[3] (in thousands)	Option Type
2008	10,800	$ 60.000	$	Puts purchased
2008	138,000	$ 78.055	(8,615)	Calls sold
2009	306,000	$ 80.017	(23,574)	Calls sold
2010	234,000	$ 83.027	(15,633)	Calls sold
2011	72,000	$ 87.296	(3,583)	Calls sold
2012	48,000	$ 83.944	(2,409)	Calls sold
			$ (53,814)	
	Total net liability		$ (504,450)	

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(1) Fair value based on independent, third-party statements, supported by observable levels at which transactions are executed in the marketplace.

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

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

(4) Puts sold and calls purchased in 2008 and 2009 represent collars entered into by us as offsetting positions for the calls sold related to ethane and propane production. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

(5) A portion of these positions were paid off during July 2008 as a result of our early termination of certain crude oil derivative contracts (see Recent Events).

(6) Mmbtu represents million British Thermal Units.

(7) Includes our premium received from our sale of an option for us to sell 468,000 mmbtu of natural gas for the year ended December 31, 2008 at $15.50 per mmbtu.

(8) Represents derivative instruments that combine a swap and a put option with the same strike price.

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 General Partner s 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 at June 30, 2008.

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.

PART II. OTHER INFORMATION

ITEM 1A. RISK FACTORS

The risk factors set forth below should be read in conjunction with those appearing in Item 1A of our Annual Report on Form 10-K for the fiscal year ended December 31, 2007.

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Due to the accounting of our derivative contracts, increases in prices for natural gas, crude oil and NGLs could result in non-cash balance sheet reductions.

With the objective of enhancing the predictability of future revenues, from time to time we enter into natural gas, natural gas liquids and crude oil derivative contracts. We account for these derivative contracts by applying the provisions of SFAS No. 133. Due to the mark-to-market accounting treatment for these derivative contracts, we could recognize incremental derivative liabilities between reporting periods resulting from increases or decreases in reference prices for natural gas, crude oil and NGLs, which could result in our recognizing a non-cash loss in our consolidated statements of operations or through accumulated other comprehensive income (loss) and a consequent non-cash decrease in our partners capital between reporting periods. Any such decrease could be substantial. In addition, we may be required to make a cash payment upon the termination of any of these derivative contracts.

Our hedging activities do not eliminate our exposure to fluctuations in commodity prices and interest rates and may reduce our cash flow and subject our earnings to increased volatility.

Our operations expose us to fluctuations in commodity prices. We utilize derivative contracts related to the future price of crude oil, natural gas and NGLs with the intent of reducing the volatility of our cash flows due to fluctuations in commodity prices. We also have exposure to interest rate fluctuations as a result of variable rate debt under our term loan and revolving credit facility. We have entered into interest rate swap agreements to convert a portion of this variable rate debt to a fixed rate obligation, thereby reducing our exposure to market rate fluctuations.

We have entered into derivative transactions related to only a portion of our crude oil, natural gas and NGL volume and our variable rate debt. As a result, we will continue to have direct commodity price risk and interest rate risk with respect to the unhedged portion of these items. To the extent we hedge our commodity price and interest rate risk using certain derivative contracts, we will forego the benefits we would otherwise experience if commodity prices or interest rates were to change in our favor.

Even though our hedging activities are monitored by management, these activities could reduce our cash flow in some circumstances, including if the counterparty to the hedging contract defaults on its contract obligations, if there is a change in the expected differential between the underlying price in the hedging agreement and the actual prices received or, with regard to commodity derivatives, if production is less than expected. With respect to commodity derivative contracts, if the actual amount of production is lower than the amount that is subject to our derivative instruments, we might be forced to satisfy all or a portion of derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a reduction of our cash flow. In addition, we have entered into proxy hedges with respect to our NGLs, typically using crude oil derivative contracts, based upon the historical price correlation between crude oil and NGLs. Certain of these proxy hedges could become less effective as a result of significant increases in the price of crude oil and less significant increases in the price of ethane and propane. If these proxy hedges remain less effective, our settlement of the contracts could result in significant costs to us.

The accounting standards regarding hedge accounting are complex, and even when we engage in hedging transactions that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our financial statements may reflect volatility due to these derivatives, even when there is no underlying economic impact at that point. In addition, it is not always possible for us to engage in a derivative transaction that completely mitigates our exposure to commodity prices and interest rates. Our financial statements may reflect a gain or loss arising from an exposure to commodity prices and interest rates for which we are unable to enter into a completely effective hedge transaction.

ITEM 6. EXHIBITS

Exhibit No.	Description
3.1	Certificate of Limited Partnership[(1)]
3.2	Second Amended and Restated Agreement of Limited Partnership[(2)]
3.2(a)	Amendment No. 1 to Second Amendment and Restated Agreement of Limited Partnership[(3)]
3.2(b)	Amendment No. 2 to Second Amendment and Restated Agreement of Limited Partnership[(4)]
3.2(c)	Amendment No. 3 to Second Amendment and Restated Agreement of Limited Partnership[(5)]
3.2(d)	Amendment No. 4 to Second Amendment and Restated Agreement of Limited Partnership[(6)]
3.3	Certificate of Designation of 6.5% Cumulative Convertible Preferred Units [(7)]
3.3(a)	Amended and Restated Certificate of Designation[(8)]
4.1	Common unit certificate[(1)]
10.1	Amendment No.1 and Agreement to Revolving Credit and Term Loan Agreement[(6)]
10.2	Common Unit Purchase Agreement dated June 17, 2008[(9)]
10.3	8 3/4% Senior Notes due 2018 Purchase Agreement dated June 24, 2008[(10)]
10.4	Indenture dated June 27, 2008[(10)]
10.5	Registration Rights Agreement dated June 27, 2008[(10)]
10.6	Increase Joinder dated June 27, 2008[(11)]
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(6) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on March 14, 2006.
(8) Previously filed as an exhibit to current report on Form 8-K on April 19, 2007.
(9) Previously filed as an exhibit to current report on Form 8-K on June 23, 2008.
(10) Previously filed as an exhibit to current report on Form 8-K on June 27, 2008.
(11) Previously filed as an exhibit to current report on Form 8-K on July 3, 2008.

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SIGNATURES

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.

ATLAS PIPELINE PARTNERS, L.P.

By: Atlas Pipeline Partners GP, LLC, its General Partner

Date: August 8, 2008	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 8, 2008	By: /s/ MICHAEL L. STAINES Michael L. Staines President, Chief Operating Officer and Managing Board Member of the General Partner
Date: August 8, 2008	By: /s/ MATTHEW A. JONES Matthew A. Jones Chief Financial Officer of the General Partner
Date: August 8, 2008	By: /s/ SEAN P. MCGRATH Sean P. McGrath Chief Accounting Officer of the General Partner