ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 09, 2013
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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, 2013

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.)**
Park Place Corporate Center One	
1000 Commerce Drive, 4th Floor	
Pittsburgh, Pennsylvania	**15275-1011**
(Address of principal executive office)	**(Zip code)**

Registrant s telephone number, including area code: (877) 950-7473

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 has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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 x	Accelerated filer ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

The number of common units of the registrant outstanding on August 6, 2013 was 77,685,907.

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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ON FORM 10-Q

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Glossary of Terms

Definitions of terms and acronyms generally used in the energy industry and in this report are as follows:

BPD	Barrels per day. Barrel measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels.
BTU	British thermal unit, a basic measure of heat energy
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
EBITDA	Net income (loss) before net interest expense, income taxes, and depreciation and amortization. EBITDA is considered to be a non-GAAP measurement.
FASB	Financial Accounting Standards Board
Fractionation	The process used to separate an NGL stream into its individual components.
GAAP	Generally Accepted Accounting Principles
G.P.	General Partner or General Partnership
GPM	Gallons per minute
Keep-Whole	Contract with producer whereby plant operator pays for or returns gas having an equivalent BTU content to the gas received at the well-head.
L.P.	Limited Partner or Limited Partnership
MCF	Thousand cubic feet
MCFD	Thousand cubic feet per day
MMBTU	Million British thermal units
MMCFD	Million cubic feet per day
NGL(s)	Natural gas liquid(s), primarily ethane, propane, normal butane, isobutane and natural gasoline
Percentage of Proceeds (POP)	Contract with natural gas producers whereby the plant operator retains a negotiated percentage of the sale proceeds.
Residue gas	The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities.
SEC	Securities and Exchange Commission

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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, 2013	December 31, 2012
ASSETS		
Current assets:		
Cash and cash equivalents	$ 21,081	$ 3,398
Funds held in escrow	50,001	25,000
Accounts receivable	206,944	157,526
Current portion of derivative assets	25,235	23,077
Prepaid expenses and other	12,760	11,074
Total current assets	316,021	220,075
Property, plant and equipment, net	2,623,078	2,200,381
Goodwill	502,321	319,285
Intangible assets, net	569,843	199,360
Equity method investment in joint ventures	232,090	86,002
Long-term portion of derivative assets	14,591	7,942
Other assets, net	46,230	32,593
Total assets	$ 4,304,174	$ 3,065,638
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 522	$ 10,835
Accounts payable affiliates	3,567	5,500
Accounts payable	36,417	59,308
Accrued liabilities	97,817	57,752
Accrued interest payable	25,893	10,399
Current portion of derivative liabilities	95	
Accrued producer liabilities	140,505	109,725
Total current liabilities	304,816	253,519
Long-term debt, less current portion	1,635,297	1,169,083
Deferred income taxes, net	35,513	30,258
Other long-term liabilities	6,387	6,370
Commitments and contingencies		
Equity:		
Class D convertible preferred limited partners interests	409,753	
Common limited partners interests	1,819,281	1,507,676
General Partner s interest	48,648	31,501
Total partners capital	2,277,682	1,539,177
Non-controlling interest	44,479	67,231
Total equity	2,322,161	1,606,408
Total liabilities and equity	$ 4,304,174	$ 3,065,638

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, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Revenue:				
Natural gas and liquids sales	$ 491,230	$ 238,801	$ 875,078	$ 528,026
Transportation, processing and other fees third parties	40,229	14,756	72,883	27,358
Transportation, processing and other fees affiliates	77	122	148	201
Derivative gain, net	27,107	67,847	15,024	55,812
Other income, net	2,296	2,588	5,718	5,003
Total revenues	560,939	324,114	968,851	616,400
Costs and expenses:				
Natural gas and liquids cost of sales	424,216	195,103	749,756	428,208
Plant operating	24,147	14,600	45,418	28,481
Transportation and compression	623	212	1,211	476
General and administrative	11,296	9,570	23,844	18,640
Compensation reimbursement affiliates	1,250	875	2,500	1,750
Other costs	18,370	(161)	18,900	(195)
Depreciation and amortization	46,383	21,712	76,841	42,554
Interest	22,581	9,269	41,267	17,977
Total costs and expenses	548,866	251,180	959,737	537,891
Equity income (loss) in joint ventures	(472)	1,917	1,568	2,813
Loss on asset disposition	(1,519)		(1,519)	
Loss on early extinguishment of debt	(19)		(26,601)	
Income (loss) before tax	10,063	74,851	(17,438)	81,322
Income tax benefit	28		37	
Net income (loss)	10,091	74,851	(17,401)	81,322
Income attributable to non-controlling interests	(1,810)	(1,061)	(3,179)	(2,597)
Preferred unit imputed dividend effect	(6,729)		(6,729)	
Preferred unit dividends	(5,341)		(5,341)	
Net income (loss) attributable to common limited partners and the General Partner	$ (3,789)	$ 73,790	$ (32,650)	$ 78,725
Allocation of net income (loss) attributable to:				
Common limited partner interest	$ (8,408)	$ 70,770	$ (39,614)	$ 74,237
General Partner interest	4,619	3,020	6,964	4,488
	$ (3,789)	$ 73,790	$ (32,650)	$ 78,725

Net income (loss) attributable to common limited partners per unit:

Basic	$ (0.11)	$ 1.30	$ (0.57)	$ 1.37
Weighted average common limited partner units (basic)	74,340	53,646	69,520	53,633
Diluted	$ (0.11)	$ 1.30	$ (0.57)	$ 1.37
Weighted average common limited partner units (diluted)	74,340	54,510	69,520	54,262

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	**2012**	**2013**	**2012**
Net income (loss)	$ 10,091	$ 74,851	$ (17,401)	$ 81,322
Other comprehensive income:				
Adjustment for realized losses on cash flow hedges reclassified to net income (loss)		1,108		2,254
Total other comprehensive income		1,108		2,254
Comprehensive income (loss)	10,091	75,959	(17,401)	83,576
Comprehensive income attributable to non-controlling interests	(1,810)	(1,061)	(3,179)	(2,597)
Preferred unit imputed dividend effect	(6,729)		(6,729)	
Preferred unit dividends	(5,341)		(5,341)	
Comprehensive income (loss) attributable to common limited partners and the General Partner	$ (3,789)	$ 74,898	$ (32,650)	$ 80,979

See accompanying notes to consolidated financial statements

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

FOR THE SIX MONTHS ENDED JUNE 30, 2013

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Units		Preferred Limited Partners	Common Limited Partners	General Partner	Non-controlling Interest	Total
	Preferred	Common					
Balance at December 31, 2012		64,556,010	$	$ 1,507,676	$ 31,501	$ 67,231	$ 1,606,408
Issuance of units and General Partner capital contribution	13,445,383	12,935,280	397,683	427,552	17,280		842,515
Issuance of common units under incentive plans		184,228		84			84
Unissued common units under incentive plans				7,601			7,601
Distributions paid				(84,018)	(7,097)		(91,115)
Contributions from non-controlling interests						5,176	5,176
Distributions to non-controlling interests						(500)	(500)
Decrease in non-controlling interest due to business combination						(30,607)	(30,607)
Net income (loss)			12,070	(39,614)	6,964	3,179	(17,401)
Balance at June 30, 2013	13,445,383	77,675,518	$ 409,753	$ 1,819,281	$ 48,648	$ 44,479	$ 2,322,161

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, 2013	Six Months Ended June 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (17,401)	$ 81,322
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	76,841	42,554
Equity income in joint ventures	(1,568)	(2,813)
Distributions received from equity method joint ventures	3,600	3,600
Non-cash compensation expense	7,820	3,918
Amortization of deferred finance costs	3,283	2,295
Loss on early extinguishment of debt	26,601	
Loss on disposal of asset	1,519	
Deferred income tax benefit	(37)	
Change in operating assets and liabilities, net of business combinations:		
Accounts receivable, prepaid expenses and other	(57,274)	24,920
Accounts payable and accrued liabilities	32,982	(42,428)
Accounts payable and accounts receivable affiliates	(1,933)	(528)
Derivative accounts payable and receivable	(8,712)	(48,309)
Net cash provided by operating activities	65,721	64,531
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(215,709)	(146,388)
Cash paid for business combinations, net of cash received	(1,000,785)	(36,689)
Other	250	250
Net cash used in investing activities	(1,216,244)	(182,827)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	865,000	480,500
Repayments under credit facility	(1,078,000)	(292,000)
Net proceeds from issuance of long term debt	1,028,449	
Repayment of debt	(365,822)	
Payment of premium on retirement of debt	(25,581)	
Payment of deferred financing costs	(893)	(3,358)
Principal payments on capital lease	(10,578)	(1,191)
Net proceeds from issuance of common and preferred limited partner units	825,235	
Purchase and retirement of treasury units		(695)
General Partner capital contributions	17,280	
Contributions from non-controlling interest holders	5,176	119
Contributions to non-controlling interest holders	(500)	
Distributions paid to common limited partners and the General Partner	(91,115)	(64,590)
Other	(445)	(400)
Net cash provided by financing activities	1,168,206	118,385
Net change in cash and cash equivalents	17,683	89

Cash and cash equivalents, beginning of period	3,398	168
Cash and cash equivalents, end of period	$ 21,081	$ 257

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, 2013

(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 gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States; natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and the transportation of NGLs in the southwestern region of the United States. 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. At June 30, 2013, Atlas Pipeline Partners GP, LLC (the General Partner) owned a combined 2.0% general partner interest in the consolidated operations of the Partnership, through which it manages and effectively controls both the Partnership and the Operating Partnership. The General Partner is a wholly-owned subsidiary of Atlas Energy, L.P. (ATLS), a publicly-traded limited partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At June 30, 2013, the Partnership had 77,675,518 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS; and 13,445,383 Class D convertible preferred units (Class D Preferred Units) outstanding (see Note 5).

The accompanying consolidated financial statements, which are unaudited, except the balance sheet at December 31, 2012, which 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, 2012. The results of operations for the six month period ended June 30, 2013 may not necessarily be indicative of the results of operations for the full year ending December 31, 2013.

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, 2012.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (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 income (loss), are referred to as other comprehensive income (loss) and for the Partnership only include changes in the fair value of unsettled derivative contracts which were previously accounted for as cash flow hedges (see Note 10). These contracts are wholly owned by the Partnership and the related gains and losses are not shared with the non-controlling interests. During the three and six months ended June 30, 2012, the Partnership reclassified $1.1 million and $2.3 million, respectively, from other comprehensive income to natural gas and liquids sales within the Partnership s

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consolidated statements of operations. As of January 1, 2013, all amounts had been reclassified out of other comprehensive income and the Partnership had no amounts outstanding within other comprehensive income.

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 by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, and net income (loss) attributable to the General Partner s and the preferred unitholders interests. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its 2.0% general partner interest and incentive distributions to be distributed for the quarter (see Note 5), with a priority allocation of net income to the General Partner s incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner s and limited partners ownership interests.

The Partnership presents net income (loss) per unit under the two-class method for master limited partnerships, which considers whether the incentive distributions of a master limited partnership represent a participating security when considered in the calculation of earnings per unit under the two-class method. The two-class method considers whether the partnership agreement contains any contractual limitations concerning distributions to the incentive distribution rights that would impact the amount of earnings to allocate to the incentive distribution rights for each reporting period. If distributions are contractually limited to the incentive distribution rights share of currently designated available cash for distributions as defined under the partnership agreement, undistributed earnings in excess of available cash should not be allocated to the incentive distribution rights. Under the two-class method, management of the Partnership believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Class D Preferred Units participate in distributions with the common limited partner units according to a predetermined formula (see Note 5), thus they are considered participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution. However, the contractual terms of the Class D Preferred Units do not require the holders to share in the losses of the entity, therefore the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the Class D Preferred Units on a pro-rata basis.

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership s phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 15), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights result in a non-contingent transfer of value each time the Partnership declares a distribution or distribution equivalent right during the award s vesting period. However, unless the contractual terms of the participating securities require the holders to share in the losses of the entity, net loss is not allocated to the participating securities. Therefore, the net income (loss) utilized in the calculation of net income (loss) per unit must be determined based upon the allocation of only net income to the phantom units on a pro-rata basis.

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The following is a reconciliation of net income (loss) allocated to the General Partner and common limited partners for purposes of calculating net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss)	$ 10,091	$ 74,851	$ (17,401)	$ 81,322
Income attributable to non-controlling interests	(1,810)	(1,061)	(3,179)	(2,597)
Preferred unit imputed dividend effect	(6,729)		(6,729)	
Preferred unit dividends	(5,341)		(5,341)	
Net income (loss) attributable to common limited partners and the General Partner	(3,789)	73,790	(32,650)	78,725
General Partner s cash incentive distributions	4,788	1,569	7,776	2,966
General Partner s ownership interest	(172)	1,451	(812)	1,522
Net income attributable to the General Partner s ownership interests	4,616	3,020	6,964	4,488
Net income (loss) attributable to common limited partners	(8,405)	70,770	(39,614)	74,237
Net income attributable to participating securities phantom units[(1)]		1,122		860
Net income attributable to participating securities Class D Preferred Units[(2)]				
Net income attributable to participating securities		1,122		860
Net income (loss) utilized in the calculation of net income from continuing operations attributable to common limited partners per unit	$ (8,405)	$ 69,648	$ (39,614)	$ 73,377

(1) Net income attributable to common limited partners ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three and six months ended June 30, 2013 net loss attributable to common limited partners ownership interest is not allocated to approximately 967,000 and 1,011,000 weighted average phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

(2) Net income attributable to common limited partners ownership interest is allocated to the Class D Preferred Units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three and six months ended June 30, 2013 net loss attributable to common limited partners ownership interest is not allocated to approximately 9,013,000 and 4,531,000 weighted average Class D Preferred Units, respectively, because the contractual terms of the Class D Preferred Units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities.

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The following table sets forth the reconciliation of the Partnership s 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,	
	2013	2012	2013	2012
Weighted average number of common limited partner units basic	74,340	53,646	69,520	53,633
Add effect of dilutive securities phantom units[1]		864		629
Add effect of convertible preferred limited partner units[2]				
Weighted average common limited partner units diluted	74,340	54,510	69,520	54,262

(1) For the three and six months ended June 30, 2013 approximately 967,000 and 1,011,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such phantom units would have been anti-dilutive.

(2) For the three and six months ended June 30, 2013, approximately 9,013,000 and 4,531,000 Class D Preferred Units, respectively 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.

Revenue Recognition

The Partnership s revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from its gathering, processing, treating and transportation 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 NGLs, if any, off delivery points on its systems. Under other agreements, the Partnership gathers natural gas across its systems, from receipt to delivery point, without taking title to the natural gas. Revenue associated with the physical sale of natural gas and NGLs is recognized upon physical delivery. In connection with the Partnership s gathering, processing and transportation operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas and for transporting NGLs. Revenue is a function of the volume of natural gas that the Partnership gathers and processes or the volume of NGLs transported and is not directly dependent on the value of the natural gas or NGLs. The Partnership is also paid a separate compression fee on many of its gathering systems. The fee is dependent upon the volume of gas flowing through its compressors and the quantity of compression stages utilized to gather the gas.

POP Contracts. These contracts provide for the Partnership to retain a negotiated percentage of the sale proceeds from residue gas and NGLs it gathers and processes, with the remainder being remitted to the producer. In this contract-type, the Partnership and the producer are directly dependent on the volume of the commodity and its value; the Partnership effectively owns a percentage of the commodity and revenues are directly correlated to its market value. POP contracts may include a fee component, which is charged to the producer.

Keep-Whole Contracts. These contracts require the Partnership, as the processor and gatherer, to gather or purchase raw natural gas at current market rates per MMBTU. The volume and energy content of gas gathered or purchased is based on the measurement at an agreed upon location (generally at the wellhead). The BTU quantity of gas redelivered or sold at the tailgate of the Partnership s processing facility may be lower than the BTU quantity purchased at the wellhead primarily due to the NGLs extracted from the natural gas when processed through a plant. The Partnership must make up or keep the producer whole for this loss in BTU quantity. To offset the make-up obligation, the Partnership retains the NGLs, which are extracted, and sells them for its own account. Therefore, the Partnership bears the economic risk (the processing margin risk) that (1) the BTU quantity of residue gas available for redelivery to the producer may be less than received from the producer; and/or (2) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements are lower in BTU content and thus can 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 when the processing margin risk is uneconomic.

The Partnership accrues unbilled revenue and the related purchase costs 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 gathering and compression fees, which are, in turn, based upon applicable product prices. The Partnership had unbilled revenues at June 30, 2013 and December 31, 2012 of $115.0 million and $100.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Accrued Producer Liabilities

Accrued producer liabilities on the Partnership s consolidated balance sheets represent accrued purchase commitments payable to producers related to gas gathered and processed through its system under its POP and Keep-Whole contracts (see Revenue Recognition).

Cash and Cash Equivalents

The Partnership considers all highly liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist principally of temporary investments of cash in short-term money market instruments. Checks outstanding at the end of a period that exceed available cash balances held at the bank are considered to be book overdrafts and are reclassified to accounts payable. At June 30, 2013, the Partnership did not have any reclassified balances related to outstanding checks. At December 31, 2012, the Partnership reclassified the balance related to outstanding checks of $27.6 million from cash and cash equivalents to accounts payable on the Partnership s consolidated balance sheets.

Recently Adopted Accounting Standards

In February 2013, the FASB issued Accounting Standards Update (ASU) 2013-02, Other Comprehensive Income (Topic 220) Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income, which, among other changes, requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component and the respective line items of net income to which the amounts were reclassified. The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2012. The Partnership began including the additional required disclosures upon the adoption of this ASU on January 1, 2013 (see Comprehensive Income (Loss)). The adoption had no material impact on the Partnership s financial position or results of operations.

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Recently Issued Accounting Standards

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists, which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership will apply these requirements upon the adoption of the ASU on January 1, 2014. The Partnership does not expect the adoption to have a material impact on its financial position or results of operations.

NOTE 3 ACQUISITIONS

Cardinal Midstream, LLC

On December 20, 2012, the Partnership completed the acquisition of 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $599.1 million in cash, including final purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies, which are referred to as the Arkoma assets, include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas. The acquisition includes a 60% interest in Centrahoma Processing, LLC (Centrahoma). The remaining 40% ownership interest in Centrahoma is held by MarkWest Oklahoma Gas Company LLC (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. Due to the recent date of the acquisition, the accounting for the business combination is based on preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date. As part of the Cardinal Acquisition, the Partnership placed $25.0 million into escrow to cover potential indemnity claims. The $25.0 million was released to the sellers during the three and six months ended June 30, 2013.

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The following table presents the values assigned to the assets acquired and liabilities assumed in the Cardinal Acquisition, based on their preliminary estimated fair values as of the date of acquisition, including the 40% non-controlling interest of Centrahoma held by MarkWest (in thousands):

Cash	$ 1,184
Accounts receivable	13,783
Prepaid expenses and other	1,289
Property, plant and equipment	246,787
Intangible assets	232,740
Goodwill	213,677
Total assets acquired	709,460
Current portion of long-term debt	(341)
Accounts payable and accrued liabilities	(14,128)
Deferred tax liability, net	(35,353)
Long-term debt, less current portion	(604)
Total liabilities acquired	(50,426)
Non-controlling interest	(58,703)
Net assets acquired	**600,331**
Less cash received	(1,184)
Net cash paid for acquisition	**$ 599,147**

The fair value of MarkWest s 40% non-controlling interest in Centrahoma was based upon the purchase price allocated to the 60% controlling interest the Partnership acquired using an income approach. This measurement uses significant inputs that are not observable in the market and thus represents a fair value measurement categorized within Level 3 of the fair value hierarchy. The 40% non-controlling interest in Centrahoma was reduced by a 5.0% adjustment for lack of control that market participants would consider when measuring its fair value.

TEAK Midstream, LLC

On May 7, 2013, the Partnership completed the acquisition of 100% of the equity interests of TEAK Midstream, LLC (TEAK) for $1.0 billion in cash, subject to customary purchase price adjustments, less cash received (the TEAK Acquisition), including $50.0 million placed into escrow pending final settlement of working capital adjustments and to cover potential indemnity claims. The assets of these companies, which are referred to as the SouthTX assets, include the following gas gathering and processing facilities in Texas:

the Silver Oak I plant, which is a 200 MMCFD cryogenic processing facility;

a second 200 MMCFD cryogenic processing facility, the Silver Oak II plant, to be in service the first quarter of 2014;

265 miles of primarily 20-24 inch gathering and residue lines;

approximately 275 miles of low pressure gathering lines;

a 75% interest in T2 LaSalle Gathering Company L.L.C. (T2 LaSalle), which owns a 62 mile, 24 inch gathering line;

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a 50% interest in T2 Eagle Ford Gathering Company L.L.C. (T2 Eagle Ford), which owns a 45 mile 16 inch gathering pipeline and is currently building a 71 mile 24 inch gathering line; and

a 50% interest in T2 EF Cogeneration Holdings L.L.C. (T2 Co-Gen), which is building a cogeneration facility.

As a result of the TEAK Acquisition, the Partnership has added additional gathering and processing capacity as well as fee-based cash flows from natural gas gathering and processing operations.

The Partnership funded the purchase price for the TEAK Acquisition in part from the private placement of $400.0 million of Class D Preferred Units for net proceeds of $397.7 million, plus the General Partner s contribution of $8.2 million to maintain its 2.0% general partner interest in the Partnership (see Note 5); and from the sale of 11,845,000 common limited partner units in a public offering for net proceeds of approximately $388.4 million, plus the General Partner s contribution of $8.3 million to maintain its 2.0% general partner interest in the Partnership (see Note 5). The Partnership funded the remaining purchase price from its senior secured revolving credit facility, and issued $400.0 million of 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes) on May 10, 2013 for net proceeds of $391.5 million to reduce the level of borrowings under the revolving credit facility as part of the TEAK Acquisition (see Note 13).

The Partnership accounted for this transaction as a business combination. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values. Due to the recent date of acquisition, the accounting for the business combination is based on preliminary data that remains subject to adjustment and could change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date and the changes could be material.

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The following table presents the preliminary values assigned as of June 30, 2013 to the assets acquired and liabilities assumed in the TEAK Acquisition, based on their estimated fair values at the date of the acquisition (in thousands):

Cash	$ 8,157
Accounts receivable	11,837
Prepaid expenses and other	567
Property, plant and equipment	290,118
Intangible assets	285,000
Goodwill	279,286
Equity method investment in joint ventures	148,120
Total assets acquired	1,023,085
Accounts payable and accrued liabilities	(15,405)
Total liabilities acquired	(15,405)
Net assets acquired	**1,007,680**
Less cash received	(8,157)
Net cash paid for acquisition	**$ 999,523**

In conjunction with the issuance of the Partnership s common limited partner units associated with the acquisition, $14.3 million of transaction fees were included in the $388.4 million net proceeds recorded within common limited partners interests on the Partnership s consolidated balance sheets. In conjunction with the issuance the Partnership s Class D Preferred Units associated with the acquisition, $2.3 million of transaction fees were included in the $397.7 million proceeds recorded within preferred limited partner interests on the Partnership s consolidated balance sheets. In conjunction with the issuance of the 4.75% Senior Notes and an amendment of the revolving credit facility, $9.4 million of transaction fees were recorded as deferred finance costs within other assets, net on the Partnership s consolidated balance sheets. Other acquisition costs of $18.2 million associated with the TEAK Acquisition were expensed as incurred and recorded to other costs on the Partnership s consolidated statements of operations.

Revenues and net losses of $20.2 million and $2.5 million, respectively, from the acquisition date of May 7, 2013 have been included in the Partnership s consolidated financial statements related to the TEAK Acquisition for the three and six months ended June 30, 2013, which were included in the Partnership s Gathering and Processing operating segment. Net earnings of $1.1 million contributed from the TEAK Acquisition from April 1, 2013 (the effective date) to May 7, 2013 (the closing date) were included as a reduction to the purchase price.

The following table provides the unaudited pro forma revenue, net income, and net income per basic and diluted common unit for the three and six months ended June 30, 2013 and 2012 as if (A)(1) the TEAK Acquisition; (2) the common unit equity offering for net proceeds of $388.4 million in April 2013; (3) the Class D Preferred Unit offering for net proceeds of $397.7 million in April 2013; (4) the General Partner s contribution of $16.5 million to maintain its 2.0% general partner interest in the Partnership; (5) the issuance of $400.0 million of 4.75% Senior Notes for net proceeds of $391.5 million; and (B) (1) the Cardinal Acquisition; (2) the equity offering for net proceeds of $319.3 million in December 2012, including General Partner contribution; (3) the $176.5 million net proceeds from the 6.625% unsecured senior notes due October 1, 2020 (6.625% Senior Notes); and (4) the borrowings under the Partnership s revolving credit facility had been included in operations commencing on January 1, 2012 (in thousands, except per unit data; unaudited):

	Three months ended June 30,		**Six months ended June 30,**	
	2013	**2012**	**2013**	**2012**
Total revenues	$ 570,825	$ 415,958	$ 1,003,328	$ 802,474

Continuing net income (loss) attributable to common limited partners and the General Partner[1]	1,978	20,425	(59,150)	(8,356)
Continuing net income (loss) attributable to common limited partner unit:				
Basic and diluted[1]	$ (0.04)	$ 0.19	$ (0.85)	$ (0.17)

(1) Pro forma earnings for the three and six months ended June 30, 2013 were adjusted to exclude $18.2 million of TEAK Acquisition related costs incurred and pro forma earnings for the three and six months ended June 30, 2012 were adjusted to include these costs.

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 the TEAK and Cardinal Acquisitions and financing transactions at the beginning of the periods shown above or the results that will be attained in the future.

NOTE 4 EQUITY METHOD INVESTMENTS

The Partnership s consolidated financial statements include its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), 75% interest in T2 LaSalle, 50% interest in T2 Eagle Ford and 50% interest in T2 EF Co-Gen. The Partnership acquired its interests in T2 LaSalle, T2 Eagle Ford, and T2 EF Co-Gen (T2 Joint Ventures) as part of the TEAK Acquisition (see Note 3). The Partnership accounts for its investments in the joint ventures under the equity method of accounting.

The Partnership evaluated whether the T2 Joint Ventures should be subject to consolidation. The T2 Joint Ventures do meet the qualifications of a Variable Interest Entity (VIE), but the Partnership does not meet the qualifications as the primary beneficiary. Even though the Partnership owns 50 or more percentage interest in the T2 Joint Ventures, the Partnership does not have controlling financial interests in these entities. The Partnership shares equal management rights with TexStar Midstream Services, L.P. (TexStar), the investor owning the remaining interests; and TexStar is the operator of the T2 Joint Ventures. The Partnership determined that it should account for the T2 Joint Ventures under the equity method, since the Partnership does not have a controlling financial interest, but does have a significant influence. The T2 Joint Ventures were formed to provide services for the benefit of the joint interest owners. The T2 Joint Ventures have capacity lease agreements with the joint interest owners, which cover the costs of operations of the T2 Joint Ventures. The Partnership s maximum exposure to loss as a result of its involvement with the VIEs includes its equity investment; any additional capital contribution commitments and the Partnership s share of any operating expenses incurred by the VIEs.

Under the equity method of accounting, the Partnership records its proportionate share of the joint ventures net income (loss) as equity income (loss) on its consolidated statements of operations. Investments in excess of the underlying net assets of equity method investees identifiable to property, plant and equipment or finite lived intangible assets are amortized over the useful life of the related assets and recorded as a reduction to equity investment on the Partnership s consolidated balance sheet with an offsetting reduction to equity income on the Partnership s consolidated statements of operations. Excess investment representing equity method goodwill is not amortized but is evaluated for impairment annually. This goodwill is not subject to amortization and is accounted for as a component of the investment. No goodwill was recorded on the acquisition of WTLPG, T2 LaSalle, T2 Eagle Ford, or T2 EF Co-Gen.

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The following table presents the Partnership s equity method investments in joint ventures as of June 30, 2013 and December 31, 2012 (in thousands):

	June 30, 2013	December 31, 2012
WTLPG	$ 86,129	$ 86,002
T2 LaSalle	50,591	
T2 Eagle Ford	85,925	
T2 EF Co-Gen	9,445	
Equity method investment in joint ventures	$ 232,090	$ 86,002

The following table presents the Partnership s equity income (loss) in joint ventures for the three and six months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
WTLPG	$ 1,687	$ 1,917	$ 3,727	$ 2,813
T2 LaSalle	(898)		(898)	
T2 Eagle Ford	(1,078)		(1,078)	
T2 EF Co-Gen	(183)		(183)	
Equity income in joint ventures	$ (472)	$ 1,917	$ 1,568	$ 2,813

NOTE 5 EQUITY

Common Units

In April 2013, the Partnership sold 11,845,000 common units of the Partnership at a price to the public of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. The Partnership also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest. The Partnership used the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition (see Note 3).

The Partnership has an equity distribution program with Citigroup Global Markets, Inc. (Citigroup). Pursuant to this program, the Partnership may offer and sell from time to time through Citigroup, as its sales agent, common units having an aggregate value of up to $150.0 million. Subject to the terms and conditions of the equity distribution agreement, Citigroup will not be required to sell any specific number or dollar amount of the common units, but will use its reasonable efforts, consistent with its normal trading and sales practices, to sell such units. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end; there will be no minimum purchase requirements; and there will be no arrangements to place the proceeds of the offering in an escrow, trust or similar account. Under the terms of the equity distribution agreement, the Partnership also may sell common units to Citigroup as principal for its own account at a price agreed upon at the time of the sale. The Partnership intends to use the net proceeds from any such offering for general partnership purposes, which may include, among other things, repayment of indebtedness, acquisitions, capital expenditures and additions to working capital. During the three and six months

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ended June 30, 2013, the Partnership issued 642,495 and 1,090,280 common units, respectively, under the equity distribution program for net proceeds of $24.5 million and $38.9 million, respectively, net of $0.5 million and $0.8 million, respectively, in commissions incurred from Citigroup. The Partnership also received capital contributions from the General Partner of $0.5 million and $0.8 million during the three and six months ended June 30, 2013, respectively, to maintain its 2.0% general partner interest in the Partnership. The net proceeds from the common unit offering were utilized for general partnership purposes.

Distributions

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders (subject to the rights of any other class or series of the Partnership s securities with the right to share in the Partnership s cash distributions) and to 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, including the General Partner s 2.0% interest. The General Partner, which holds all the incentive distribution rights in the Partnership, has agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to the Partnership after the General Partner receives the initial $7.0 million per quarter of incentive distribution rights.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods beginning with the distribution for the quarter ended June 30, 2013. Thereafter, the Class D Preferred Units will receive distributions in cash, Class D Preferred Units or a combination of cash and Class D Preferred Units, at the discretion of the General Partner. Cash distributions will be paid prior to any other distributions of available cash.

Common unit and General Partner distributions declared by the Partnership for quarters ending from March 31, 2012 through March 31, 2013 were as follows:

For Quarter Ended	Date Cash Distribution Paid	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)
March 31, 2012	May 15, 2012	$ 0.56	$ 30,030	$ 2,217
June 30, 2012	August 14, 2012	0.56	30,085	2,221
September 30, 2012	November 14, 2012	0.57	30,641	2,409
December 31, 2012	February 14, 2013	0.58	37,442	3,117
March 31, 2013	May 15, 2013	0.59	45,382	3,980

On July 23, 2013, the Partnership declared a cash distribution of $0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2013. The $54.0 million distribution, including $5.9 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2013 to unitholders of record at the close of business on August 7, 2013.

Class D Preferred Units

On May 7, 2013, the Partnership completed a private placement of $400.0 million of its Class D Preferred Units to third party investors, at a negotiated price per unit of $29.75, resulting in net proceeds of $397.7 million pursuant to the Class D preferred unit purchase agreement dated April 16, 2013 (the Commitment Date). The General Partner contributed $8.2 million to maintain its 2.0% general partnership interest upon the issuance of the Class D Preferred Units. The Partnership used the proceeds to fund a portion of the purchase price of the TEAK Acquisition (see Note 3). The Class D Preferred Units were offered and sold in a private transaction exempt from registration under Section 4(2) of the

Securities Act of 1933, as amended. The Partnership has the right to convert the Class D Preferred Units, in whole but not in part, beginning one year following their issuance, into common units, subject to customary anti-dilution adjustments. Unless previously converted, all Class D Preferred Units will convert into common units at the end of eight full quarterly periods following their issuance. In the event of any liquidation, dissolution or winding up of the Partnership or the sale or other disposition of all or substantially all of the assets of the Partnership, the holders of the Class D Preferred Units are entitled to receive, out of the assets of the Partnership available for distribution to unit holders, prior and in preference to any distribution of any assets of the Partnership to the holders of any other existing or subsequently issued units, an amount equal to $29.75 per Class D Preferred Unit plus any unpaid preferred distributions.

The fair value of the Partnership s common units on the Commitment Date of the Class D Preferred Units was $36.52 per unit, resulting in an embedded beneficial conversion discount (discount) on the Class D Preferred Units of $91.0 million. The Partnership recognized the fair value of the Class D Preferred Units with the offsetting intrinsic value of the discount within Class D preferred limited partner interests on its consolidated balance sheets as of June 30, 2013. The discount will be accreted and recognized as imputed dividends over the term of the Class D Preferred Units as a reduction to net income attributable to the common limited partners and the General Partner on the Partnership s consolidated statements of operations. For the three and six months ended June 30, 2013, the Partnership recorded $6.7 million within preferred unit imputed dividend effect on the Partnership s consolidated statements of operations to recognize the accretion of the beneficial conversion discount. The Class D Preferred Units are presented combined with a net $84.3 million unaccreted beneficial conversion discount on the Partnership s consolidated balance sheets.

The Class D Preferred Units will receive distributions of additional Class D Preferred Units for the first four full quarterly periods following their issuance, and thereafter will receive distributions in Class D Preferred Units, or cash, or a combination of Class D Preferred Units and cash, at the discretion of the Partnership s General Partner. Distributions will be determined based upon the cash distribution declared each quarter on the Partnership s common limited partner units plus a preferred yield premium. Class D Preferred Unit distributions, whether in kind units or in cash, will be accounted for as a reduction to net income attributable to the common limited partners and the General Partner. For the three and six months ended June 30, 2013, the Partnership recorded costs related to preferred unit distributions of $5.3 million on the Partnership s consolidated statements of operations.

Upon the issuance of the Class D Preferred Units, the Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class D Preferred Units. The Partnership agreed to use its commercially reasonable efforts to have the registration statement declared effective within 180 days of the date of conversion.

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NOTE 6 PROPERTY, PLANT AND EQUIPMENT

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 13) (in thousands):

	June 30, 2013	December 31, 2012	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 2,769,428	$ 2,294,024	2 40
Rights of way	186,597	178,234	20 40
Buildings	10,248	8,224	40
Furniture and equipment	12,154	10,305	3 7
Other	15,553	14,761	3 10
	2,993,980	2,505,548	
Less accumulated depreciation	(370,902)	(305,167)	
	$ 2,623,078	$ 2,200,381	

The Partnership recorded depreciation expense on property, plant and equipment, including capital lease arrangements (see Note 13), of $24.2 million and $15.7 million for the three months ended June 30, 2013 and 2012, respectively, and $46.5 million and $30.8 million for the six months ended June 30, 2013 and 2012, respectively, on its consolidated statements of operations.

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 interest rate used to capitalize interest on borrowed funds was 5.8% and 6.3% for the three months ended June 30, 2013 and 2012, respectively, and 6.0% and 6.5% for the six months ended June 30, 2013 and 2012, respectively. The amount of interest capitalized was $1.3 million and $2.0 million for the three months ended June 30, 2013 and 2012, respectively, and $3.8 million and $4.2 million for the six months ended June 30, 2013 and 2012, respectively.

NOTE 7 GOODWILL AND INTANGIBLE ASSETS

Goodwill is the cost of an acquisition less the fair value of the net identifiable assets of the acquired business. The Partnership reflected goodwill on its consolidated balance sheets of $502.3 million and $319.3 million at June 30, 2013 and December 31, 2012, respectively. The change in goodwill is primarily related to an addition of $279.3 million of goodwill from the TEAK Acquisition offset by a $97.2 million reduction in goodwill related to an adjustment of the fair value of assets acquired and liabilities assumed from the Cardinal Acquisition. The goodwill related to the Cardinal Acquisition is a result of the strategic industry position and potential future synergies. The goodwill related to the TEAK Acquisition is a result of the strategic industry position (see Note 3).

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions including the Cardinal and TEAK Acquisitions. The following table reflects the components of intangible assets being amortized at June 30, 2013 and December 31, 2012 (in thousands):

	June 30, 2013	December 31, 2012	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 3,419	$ 119,933	7 10
Customer relationships	722,653	205,313	7 10
	726,072	325,246	
Accumulated amortization:			
Customer contracts	(528)	(746)	
Customer relationships	(155,701)	(125,140)	
	(156,229)	(125,886)	
Net carrying amount:			
Customer contracts	2,891	119,187	
Customer relationships	566,952	80,173	
Net carrying amount	$ 569,843	$ 199,360	

The weighted-average amortization period for customer contracts and customer relationships is 9.7 years and 7.9 years, respectively. The Partnership recorded amortization expense on intangible assets of $22.2 million and $6.0 million for the three months ended June 30, 2013 and 2012, respectively, and $30.3 million and $11.8 million for the six months ended June 30, 2013 and 2012, respectively, on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: remainder of 2013 $47.8 million; 2014 $92.0 million; 2015 through 2016 $86.8 million per year; 2017 $80.7 million.

The valuation assessment for the Cardinal and TEAK Acquisitions have not been completed as of June 30, 2013 and the estimates of fair value of goodwill and intangible assets with finite lives reflected as of June 30, 2013 are subject to change and the change may be material (see Note 3).

NOTE 8 OTHER ASSETS

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

	June 30, 2013	December 31, 2012
Deferred finance costs, net of accumulated amortization of $18,351 and $23,536 at June 30, 2013 and December 31, 2012, respectively	$ 44,384	$ 30,496
Security deposits	1,846	2,097
	$ 46,230	$ 32,593

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 13). The Partnership incurred $9.4 million and $3.3 million deferred finance costs during the three months ended June 30, 2013 and 2012, respectively, and $22.4 million and $3.3 million deferred finance costs during the six months ended June 30, 2013 and 2012, respectively, related to various financing activities (see Note 13). During the six months ended June 30, 2013, the Partnership redeemed all of its outstanding $365.8 million 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) (see Note 13). The Partnership recorded $5.3 million of accelerated amortization of deferred financing costs associated with the retirement of debt during the six months ended June 30, 2013 related to the retirement of the 8.75% Senior Notes, which is included in loss on early extinguishment of debt on the Partnership s consolidated statement of operations. There was no accelerated amortization of deferred financing costs during the six months ended June 30, 2012. Amortization expense of deferred finance costs, excluding accelerated amortization expense was $1.7 million and $1.1 million for the three months ended June 30, 2013 and 2012, respectively, and $3.3 million and $2.3 million for the six months ended June 30, 2013 and 2012, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations.

NOTE 9 INCOME TAXES

As part of the Cardinal Acquisition (see Note 3), the Partnership acquired APL Arkoma, Inc., a taxable subsidiary. The components of the federal and state income tax benefit of the Partnership s taxable subsidiary at June 30, 2013 are summarized as follows (in thousands):

	Three Months Ended June 30, 2013	Six Months Ended June 30, 2013
Deferred benefit :		
Federal	$ (25)	$ (33)
State	(3)	(4)
Total income tax benefit	$ (28)	$ (37)

The components of net deferred tax liabilities as of June 30, 2013 and December 31, 2012 consist of the following (in thousands):

	June 30, 2013	December 31, 2012
Deferred tax assets:		
Net operating loss tax carryforwards and alternative minimum tax credits	$ 11,536	$ 10,277
Deferred tax liabilities:		
Excess of asset carrying value over tax basis	(47,049)	(40,535)
Net deferred tax liabilities	$ (35,513)	$ (30,258)

As of June 30, 2013, the Partnership had net operating loss carry forwards for federal income tax purposes of approximately $29.6 million, which expire at various dates from 2029 to 2032. Management of the General Partner believes it more likely than not that the deferred tax asset will be fully utilized.

NOTE 10 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price risk management activities. The Partnership uses financial swap and put 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. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under its swap agreements, the Partnership receives a fixed price and remits a floating price based on certain indices for the relevant contract period. The swap agreement sets a fixed price for the product being hedged. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract

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period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. A costless collar is a combination of a purchased put option and a sold call option, in which the premiums net to zero. A costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. Changes in fair value of derivatives are recognized immediately within derivative gain (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership s consolidated balance sheets, was reclassified to the Partnership s consolidated statements of operations at the time the originally hedged physical transactions affected earnings.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of setoff at the time of settlement of the derivatives. Due to the right of setoff, derivatives are recorded on the Partnership s consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership s consolidated balance sheets as the initial value of the options. Changes in the fair value of the options are recognized within derivative gain (loss), net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premiums are reclassified to realized gain (loss) within derivative gain (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative assets on its consolidated balance sheets of $39.7 million and $31.0 million at June 30, 2013 and December 31, 2012, respectively.

The following tables summarizes the Partnership s gross fair values of its derivative instruments, presenting the impact of offsetting derivative assets and liabilities on the Partnership s consolidated balance sheets for the periods indicated (in thousands):

Offsetting of Derivative Assets

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
As of June 30, 2013:			
Current portion of derivative assets	$ 25,877	$ (642)	$ 25,235
Long-term portion of derivative assets	15,630	(1,039)	14,591
Current portion of derivative liabilities	5	(5)	
Total derivative assets, net	$ 41,512	$ (1,686)	$ 39,826
As of December 31, 2012:			
Current portion of derivative assets	$ 23,534	$ (457)	$ 23,077
Long-term portion of derivative assets	9,637	(1,695)	7,942
Total derivative assets, net	$ 33,171	$ (2,152)	$ 31,019

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Offsetting of Derivative Liabilities

	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Liabilities Presented in the Consolidated Balance Sheets
As of June 30, 2013:			
Current portion of derivative assets	$ (642)	$ 642	$
Long-term portion of derivative assets	(1,039)	1,039	
Current portion of derivative liabilities	(100)	5	(95)
Total derivative liabilities, net	$ (1,781)	$ 1,686	$ (95)
As of December 31, 2012:			
Current portion of derivative liabilities	$ (457)	$ 457	$
Long-term portion of derivative liabilities	(1,695)	1,695	
Total derivative liabilities, net	$ (2,152)	$ 2,152	$

The following table summarizes the Partnership s commodity derivatives as of June 30, 2013, (dollars and volumes in thousands):

Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Fixed price				
2013	Natural gas	3,100	$ 3.69	$ 85
2014	Natural gas	12,600	3.98	454
2015	Natural gas	15,160	4.24	1,342
2016	Natural gas	3,750	4.40	193
2013	NGLs	27,468	1.25	10,880
2014	NGLs	55,566	1.25	8,278
2015	NGLs	23,688	1.11	2,213
2013	Crude oil	153	96.87	159
2014	Crude oil	312	92.37	412
2015	Crude oil	60	85.13	(65)
Total fixed price swaps				23,951

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Production Period	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Purchased Put Options				
2013	Natural gas	600	4.13	319
2013	NGLs	23,184	1.90	6,646
2014	NGLs	3,150	1.03	377
2015	NGLs	1,260	0.88	183
2013	Crude oil	147	100.10	989
2014	Crude oil	449	94.69	4,313
2015	Crude oil	270	89.18	2,953
Total options				15,780
Total derivatives				$ 39,731

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 11 for discussion on fair value methodology.

The following tables summarize the gross effect of all derivative instruments on the Partnership s consolidated statements of operations for the periods indicated (in thousands):

	For the Three Months ended June 30, 2013	For the Three Months ended June 30, 2012	For the Six Months ended June 30, 2013	For the Six Months ended June 30, 2012
Derivatives previously designated as cash flow hedges				
Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales	$	$ (1,108)	$	$ (2,254)
Derivatives not designated as hedges				
Gain recognized in derivative gain, net				
Commodity contract realized(1)	$ 2,844	$ 3,685	$ 4,480	$ 2,922
Commodity contract unrealized(2)	24,263	64,162	10,544	52,890
Derivative gain, net	$ 27,107	$ 67,847	$ 15,024	$ 55,812

(1) Realized loss represents the loss incurred when the derivative contract expires and/or is cash settled.
(2) Unrealized loss represents the mark-to-market loss recognized on open derivative contracts, which have not yet been settled.

NOTE 11 FAIR VALUE OF FINANCIAL INSTRUMENTS

The Partnership uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect the Partnership s own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following hierarchy:

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.

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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 assumptions 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 a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 10). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership has a financial risk management committee (the Financial Risk Management Committee), which sets the policies, procedures and valuation methods utilized by the Partnership to value its derivative contracts. The Financial Risk Management Committee members include, among others, the Chief Executive Officer, the Chief Financial Officer and the Executive Vice Chairman of the managing board of the General Partner. The Financial Risk Management Committee receives daily reports and meets on a weekly basis to review the risk management portfolio and changes in the fair value in order to determine appropriate actions.

Derivative Instruments

At June 30, 2013, the valuations for all the Partnership s derivative contracts are defined as Level 2 assets and liabilities within the same class of nature and risk, with the exception of the Partnership s NGL fixed price swaps and NGL options, which are defined as Level 3 assets and liabilities within the same class of nature and risk.

The Partnership s Level 2 commodity derivatives include natural gas and crude oil swaps and options, which are calculated based upon observable market data related to the change in price of the underlying commodity. These swaps and options are calculated by utilizing the New York Mercantile Exchange (NYMEX) quoted prices for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

Valuations for the Partnership s NGL options are based on forward price curves developed by financial institutions, and therefore are defined as Level 3. The NGL options are over-the-counter instruments that are not actively traded in an open market, thus the Partnership utilizes the valuations provided by the financial institutions that provide the NGL options for trade. The Partnership tests these valuations for reasonableness through the use of an internal valuation model.

Valuations for the Partnership s NGL fixed price swaps are based on forward price curves provided by a third party, which the Partnership considers to be Level 3 inputs. The prices are adjusted based upon the relationship between the prices for the product/locations quoted by the third party and the underlying product/locations utilized for the swap contracts, as determined by a regression model of the historical settlement prices for the different product/locations. The regression model is recalculated on a quarterly basis. This adjustment is an unobservable Level 3 input. The NGL fixed price swaps are over-the-counter instruments which are not actively traded in an open market. However, the prices for the underlying products and locations do have a direct correlation to the prices for the products and locations provided by the third party, which are based upon trading activity for the products and locations quoted. A change in the relationship between these prices would have a direct impact upon the unobservable adjustment utilized to calculate the fair value of the NGL fixed price swaps.

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The following table represents the Partnership s derivative assets and liabilities recorded at fair value as of June 30, 2013 and December 31, 2012 (in thousands):

	Level 1	Level 2	Level 3	Total
June 30, 2013				
Assets				
Commodity swaps	$	$ 4,041	$ 21,691	$ 25,732
Commodity options		8,574	7,206	15,780
Total assets		12,615	28,897	41,512
Liabilities				
Commodity swaps		(1,462)	(319)	(1,781)
Total liabilities		(1,462)	(319)	(1,781)
Total derivatives	$	$ 11,153	$ 28,578	$ 39,731
December 31, 2012				
Assets				
Commodity swaps	$	$ 2,007	$ 17,573	$ 19,580
Commodity options		7,322	6,269	13,591
Total assets		9,329	23,842	33,171
Liabilities				
Commodity swaps		(1,393)	(759)	(2,152)
Total liabilities		(1,393)	(759)	(2,152)
Total derivatives	$	$ 7,936	$ 23,083	$ 31,019

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the six months ended June 30, 2013 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance December 31, 2012	87,066	$ 16,814	38,556	$ 6,269	$ 23,083
New contracts[(1)]	48,132		5,670	619	619
Cash settlements from unrealized gain (loss)[(2)(3)]	(28,476)	(8,831)	(16,632)	3,497	(5,334)
Net change in unrealized gain (loss)[(2)]		13,389		2,002	15,391
Deferred option premium recognition[(3)]				(5,181)	(5,181)
Balance June 30, 2013	106,722	$ 21,372	27,594	$ 7,206	$ 28,578

(1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.

(2) Included within derivative income, net on the Partnership s consolidated statements of operations.
(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

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The following table provides a summary of the unobservable inputs used in the fair value measurement of the Partnership s NGL fixed price swaps at June 30, 2013 and December 31, 2012 (in thousands):

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of June 30, 2013				
Propane swaps	81,900	$ 16,565	$ (180)	$ 16,385
Isobutane swaps	5,040	(1,072)	752	(320)
Normal butane swaps	3,780	952	169	1,121
Natural gasoline swaps	16,002	6,460	(2,274)	4,186
Total NGL swaps June 30, 2013	106,722	$ 22,905	$ (1,533)	$ 21,372
As of December 31, 2012				
Propane swaps	69,678	$ 16,302	$ (552)	$ 15,750
Isobutane swaps	1,134	(219)	187	(32)
Normal butane swaps	6,174	(909)	242	(667)
Natural gasoline swaps	10,080	3,247	(1,484)	1,763
Total NGL swaps December 31, 2012	87,066	$ 18,421	$ (1,607)	$ 16,814

(1) Based upon the difference between the quoted market price provided by the third party and the fixed price of the swap.

(2) Product and location basis differentials calculated through the use of a regression model, which compares the difference between the settlement prices for the products and locations quoted by the third party and the settlement prices for the actual products and locations underlying the derivatives, using a three year historical period.

The following table provides a summary of the regression coefficient utilized in the calculation of the unobservable inputs for the Level 3 fair value measurements for the NGL fixed price swaps for the periods indicated (in thousands):

	Level 3 NGL Swap Fair Value Adjustments	Adjustment based upon Regression Coefficient		
		Lower 95%	Upper 95%	Average
As of June 30, 2013:				
Propane	$ (180)	0.8951	0.905	0.9001
Isobutane	752	1.1225	1.1319	1.1272
Normal butane	169	1.0361	1.0405	1.0383
Natural gasoline	(2,274)	0.9116	0.9321	0.9219
Total Level 3 adjustments June 30, 2013	$ (1,533)			
As of December 31, 2012:				
Propane	$ (552)	0.9019	0.9122	0.9071
Isobutane	187	1.1285	1.1376	1.1331
Normal butane	242	1.037	1.0416	1.0393
Natural gasoline	(1,484)	0.8988	0.9169	0.9078
Total Level 3 adjustments December 31, 2012	$ (1,607)			

The Partnership had $9.1 million and $7.8 million of NGL linefill at June 30, 2013 and December 31, 2012, respectively, which was included within prepaid expenses and other on its consolidated balance sheets. The NGL linefill represents amounts receivable for NGLs delivered to counterparties for which the counterparty will pay at a designated later period at a price determined by the then market price. The

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Partnership s NGL linefill is defined as a Level 3 asset and is valued using the same forward price curve utilized to value the Partnership s NGL fixed price swaps. The product/location adjustment based upon the multiple regression analysis, which was included in the value of the linefill, was a reduction of $0.3 million and $0.4 million as of June 30, 2013 and December 31, 2012, respectively.

The following table provides a summary of changes in fair value of the Partnership s NGL linefill for the three months ended June 30, 2013 (in thousands):

	NGL Linefill	
	Gallons	Amount
Balance December 31, 2012	9,148	$ 7,783
NGL linefill additions(1)	2,862	2,659
Net change in NGL linefill valuation(2)		(1,366)
Balance June 30, 2013	12,010	$ 9,076

(1) NGL linefill resulting from the addition of new transportation contracts.
(2) Included within natural gas and liquid sales on the Partnership s consolidated statements of operations.

Contingent Consideration

In February 2012, the Partnership acquired a gas gathering system and related assets for an initial net purchase price of $19.0 million. The Partnership originally agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes are achieved on the acquired gathering system within a specified time period (Trigger Payments). Sufficient volumes were achieved in December 2012 and the Partnership paid the first Trigger Payment of $6.0 million in January 2013. As of June 30, 2013, the fair value of the remaining Trigger Payment resulted in a $6.0 million long term liability, which was recorded within other long term liabilities on the Partnership s consolidated balance sheets. The range of the undiscounted amount the Partnership could pay related to the remaining Trigger Payment is between $0.0 and $6.0 million.

Other Financial Instruments

The estimated fair value of the Partnership s other financial instruments has been determined based upon its assessment of available market information and valuation methodologies. However, these estimates may not necessarily be indicative of the amounts the Partnership could realize upon the sale or refinancing of such financial instruments.

The Partnership s current assets and liabilities on its consolidated balance sheets, other than the derivatives, NGL linefill and contingent consideration discussed above, are considered to be financial instruments for which the estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1 values. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value and thus is categorized as a Level 1 value. The estimated fair value of the Partnership s Senior Notes (see Note 13) is based upon the market approach and calculated using the yield of the Senior Notes as provided by financial institutions and thus is categorized as a Level 3 value. The estimated fair values of the Partnership s total debt at June 30, 2013 and December 31, 2012, which consists principally of borrowings under the revolving credit facility and the Senior Notes, were $1,547.9 million and $1,216.4 million, respectively, compared with the carrying amounts of $1,635.8 million and $1,179.9 million, respectively.

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Acquisitions

On December 20, 2012, the Partnership completed the Cardinal Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation. The estimates of fair value as of the acquisition date which are reflected in the Partnership s consolidated balance sheet as of June 30, 2013, are subject to change and the changes could be material.

On May 7, 2013, the Partnership completed the TEAK Acquisition (see Note 3). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. These inputs require significant judgments and estimates at the time of the valuation. The estimates of fair value as of the acquisition date, which are reflected as of June 30, 2013, are subject to change and the changes made could be material.

NOTE 12 ACCRUED LIABILITIES

The following is a summary of accrued liabilities (in thousands):

	June 30, 2013	December 31, 2012
Accrued capital expenditures	$ 11,491	$ 8,336
Cardinal and TEAK Acquisitions payable (offset by funds in escrow)	50,001	25,000
Acquisition-based short-term contingent consideration		6,000
Accrued ad valorem taxes	10,701	3,950
Other	25,624	14,466
	$ 97,817	$ 57,752

NOTE 13 DEBT

Total debt consists of the following (in thousands):

	June 30, 2013	December 31, 2012
Revolving credit facility	$ 80,000	$ 293,000
8.750% Senior notes due 2018		370,184
6.625% Senior notes due 2020	504,894	505,231
5.875% Senior notes due 2023	650,000	
4.750% Senior notes due 2021	400,000	
Capital lease obligations	925	11,503
Total debt	1,635,819	1,179,918
Less current maturities	(522)	(10,835)
Total long term debt	$ 1,635,297	$ 1,169,083

Cash payments for interest related to debt, net of capitalized interest, were $0.4 million and $15.9 million for the three months ended June 30, 2013 and 2012, respectively, and $22.5 million and $15.3 million for the six months ended June 30, 2013 and 2012, respectively.

Revolving Credit Facility

At June 30, 2013, the Partnership had a $600.0 million senior secured revolving credit facility with a syndicate of banks that matures in May 2017. Borrowings under the revolving credit facility bear interest, at the Partnership s option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at June 30, 2013, was 3.2%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.4 million was outstanding at June 30, 2013. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At June 30, 2013, the Partnership had $519.6 million of remaining committed capacity under its revolving credit facility.

Borrowings under the revolving credit facility are secured by (i) a lien on and security interest in all the Partnership s property and that of its subsidiaries, except for the assets owned by Atlas Pipeline Mid-Continent WestOk, LLC (WestOK LLC) and Atlas Pipeline Mid-Continent WestTex, LLC (WestTX LLC), entities in which the Partnership has 95% interests, and Centrahoma, in which the Partnership has a 60% interest; and their respective subsidiaries; and (ii) by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including requirements that the Partnership maintain certain financial thresholds and restrictions on the Partnership s ability to (1) incur additional indebtedness, (2) make certain acquisitions, loans or investments, (3) make distribution payments to its unitholders if an event of default exists, or (4) enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is unable to borrow under its revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to its partnership agreement.

The events that constitute an event of default for the revolving credit facility are also customary for loans of this size, including payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against the Partnership in excess of a specified amount, and a change of control of the Partnership s General Partner.

On April 19, 2013, the Partnership entered into an amendment to the credit agreement which, among other changes, adjusted certain covenant ratio limits and adjusted the method of calculation as result of the TEAK Acquisition. As of June 30, 2013, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At June 30, 2013, the Partnership had $500.0 million principal outstanding of 6.625% Senior Notes, $650.0 million principal outstanding of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes), and $400.0 million of 4.75% Senior Notes (with the 6.625% Senior Notes and 5.875% Senior Notes, the Senior Notes).

The 6.625% Senior Notes are presented combined with a net $4.9 million unamortized premium as of June 30, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

In connection with the issuance of the 6.625% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by September 23, 2013 in the case of the 6.625% Senior Notes issued in September 2012, or by December 15, 2013, in the case of the 6.625% Senior Notes issued in December 2012. If the Partnership does not meet the aforementioned deadline, the 6.625% Senior Notes issued on September 28, 2012 and December 20, 2012 will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated. On July 22, 2013, the Partnership filed its registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement.

On February 11, 2013, the Partnership issued $650.0 million of the 5.875% Senior Notes in a private placement transaction. The 5.875% Senior Notes were issued at par. The Partnership received net proceeds of $637.3 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% unsecured senior notes due June 15, 2018 (8.75% Senior Notes) and repay a portion of the outstanding indebtedness under the revolving credit agreement. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

In connection with the issuance of the 5.875% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by February 6, 2014. If the Partnership does not meet the aforementioned deadline, the 5.875% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated.

On May 10, 2013, the Partnership issued $400.0 million of the 4.75% Senior Notes in a private placement transaction. The 4.75% Senior Notes were issued at par. The Partnership received net proceeds of $391.5 million after underwriting commissions and other transactions costs and utilized the proceeds to repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition (see Note 3). Interest on the 4.75% Senior Notes is payable semi-annually in arrears on May 15 and November 15. The 4.75% Senior Notes are due on November 15, 2021 and are redeemable any time after March 15, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption.

In connection with the issuance of the 4.75% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by May 5, 2014. If the Partnership does not meet the aforementioned deadline, the 4.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the Partnership causes the exchange offer to be consummated.

On January 28, 2013, the Partnership commenced a cash tender offer for any and all of its outstanding $365.8 million 8.75% Senior Notes, excluding unamortized premium, and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture governing the 8.75% Senior Notes (8.75% Senior Notes Indenture). Approximately $268.4 million aggregate principal amount of the 8.75% Senior Notes were validly tendered as of the expiration date of the consent solicitation. In February 2013, the Partnership accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid $291.4 million to redeem the $268.4 million principal plus $11.2 million make-whole premium, $3.7 million accrued interest and

$8.0 million consent payment. The Partnership entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture. The Partnership also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer.

On March 12, 2013, the Partnership paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. The Partnership funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes. During the six months ended June 30, 2013, the Partnership recorded a loss of $26.6 million within loss on early extinguishment of debt on the Partnership s consolidated statements of operations, related to the redemption of the 8.75% Senior Notes. The loss includes $17.5 million premiums paid; $8.0 million consent payment; $5.3 million write off of deferred financing costs, offset by $4.2 million recognition of unamortized premium.

The Senior Notes are 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 revolving credit facility.

Indentures governing the Senior Notes 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 its assets. The Partnership is in compliance with these covenants as of June 30, 2013.

Capital Leases

The following is a summary of the leased property under capital leases as of June 30, 2013 and December 31, 2012, which are included within property, plant and equipment (see Note 6) (in thousands):

	June 30, 2013	December 31, 2012
Pipelines, processing and compression facilities	$ 2,085	$ 15,457
Less accumulated depreciation	(240)	(1,066)
	$ 1,845	$ 14,391

On May 30, 2013, the Partnership accelerated payment on certain leases and purchased the leased property by paying approximately $7.5 million in accordance with the lease agreements. These leases were to mature in August 2013.

Depreciation expense for leased properties was $39 thousand and $185 thousand for the three months ended June 30, 2013 and 2012, respectively, and $250 thousand and $352 thousand for the six months ended June 30, 2013 and 2012, respectively, which is included within depreciation and amortization expense on the Partnership s consolidated statements of operations (see Note 6).

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NOTE 14 COMMITMENTS AND CONTINGENCIES

The Partnership has certain long-term unconditional purchase obligations and commitments, consisting primarily of transportation contracts. These agreements provide for transportation services to be used in the ordinary course of the Partnership s operations. Transportation fees paid related to these contracts were $3.1 million and $2.5 million for three months ended June 30, 2013 and 2012, respectively and $6.1 million and $5.0 million for six months ended June 30, 2013 and 2012, respectively. The future fixed and determinable portion of the obligations as of June 30, 2013 was as follows: remainder of 2013 $4.9 million; 2014 $9.5 million; and 2015 to 2017 $3.5 million per year.

The Partnership had committed approximately $178.0 million for the purchase of property, plant and equipment at June 30, 2013.

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.

NOTE 15 BENEFIT PLANS

Generally, all share-based payments to employees, which are not cash settled, including grants of unit options and phantom units, are recognized within equity in the financial statements based on their fair values on the date of the grant. Share-based payments to non-employees, which have a cash settlement option, are recognized within liabilities in the financial statements based upon their current fair market value.

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted 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. The compensation committee appointed by the General Partner s managing board (the Compensation Committee) determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The Compensation Committee determines how the exercise price may be paid by the grantee as well as the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant. There were no unit options outstanding as of June 30, 2013.

Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan (2004 LTIP) and a 2010 Long-Term Incentive Plan (2010 LTIP and collectively with the 2004 LTIP, the LTIPs) in which officers, employees, non-employee managing board members of the General Partner, employees of the General Partner s affiliates and consultants are eligible to participate. The LTIPs are administered by the Compensation Committee. Under the LTIPs, the Compensation Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At June 30, 2013, the Partnership had 909,012 phantom units outstanding under the Partnership s LTIPs, with 1,482,642 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options, which have vested and have been exercised.

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Partnership Phantom Units.

Through June 30, 2013, phantom units granted to employees under the LTIPs generally had vesting periods of four years. Phantom units awarded to non-employee managing board members will vest over a four year period. Awards to non-employee members of the board automatically vest upon a change of control, as defined in the LTIPs. At June 30, 2013, there were 301,226 units outstanding under the LTIPs that will vest within the following twelve months.

All phantom units outstanding under the LTIPs at June 30, 2013 include DERs granted to the participants by the Compensation Committee. The amounts paid with respect to LTIP DERs were $0.6 million and $0.6 million, during the three months ended June 30, 2013 and 2012, respectively and $1.2 million and $0.8 million, during the six months ended June 30, 2013 and 2012, respectively. These amounts were recorded as reductions of equity on the Partnership s consolidated balance sheets.

The following table sets forth the Partnership s LTIPs phantom unit activity for the periods indicated:

	Three Months Ended June 30,				Six Months Ended June 30,			
	2013		2012		2013		2012	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	1,057,083	$ 33.22	390,567	$ 21.41	1,053,242	$ 33.21	394,489	$ 21.63
Granted	36,971	38.10	693,952	34.97	43,775	37.32	698,084	34.98
Forfeited	(2,100)	32.95	(3,950)	24.66	(2,100)	32.95	(3,950)	24.66
Matured and issued(2)	(182,942)	32.65	(108,167)	11.35	(185,905)	32.59	(116,221)	13.32
Outstanding, end of period(3)(4)	909,012	$ 33.54	972,402	$ 32.19	909,012	$ 33.54	972,402	$ 32.19
Matured and not issued(5)	39,347	$ 24.91	48,647	$ 24.12	39,347	$ 24.91	48,647	$ 24.12
Non-cash compensation expense recognized (in thousands)		$ 3,436		$ 2,940		$ 7,820		$ 3,918

(1) Fair value based upon weighted average grant date price.

(2) The intrinsic values for phantom unit awards exercised during the three months ended June 30, 2013 and 2012 were $6.6 million and $3.2 million, respectively, and $6.7 million and $3.5 million during the six months ended June 30, 2013 and 2012, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2013 and 2012 was $34.7 million and $30.3 million, respectively.

(4) There were 22,546 and 17,852 outstanding phantom unit awards at June 30, 2013 and 2012, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.

(5) The aggregate intrinsic value for phantom unit awards vested but not issued at June 30, 2013 and 2012 was $1.5 million and $1.5 million, respectively.

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At June 30, 2013, the Partnership had approximately $17.2 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.0 years.

NOTE 16   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 ATLS. 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 its 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 ATLS 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 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 $1.3 million and $0.9 million for the three months ended June 30, 2013 and 2012, respectively, and $2.5 million and $1.8 million for the six months ended June 30, 2013 and 2012, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the six months ended June 30, 2013 and 2012. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

The Partnership compresses and gathers gas for Atlas Resource Partners, L.P. (NYSE: ARP) (ARP) on its gathering systems located in Tennessee. ARP s general partner is wholly-owned by ATLS, and two members of the General Partner s managing board are members of ARP s board of directors. The Partnership entered into an agreement to provide these services, which extends for the life of ARP s leases, in February 2008. The Partnership charged ARP approximately $77 thousand and $122 thousand in compression and gathering fees for the three months ended June 30, 2013 and 2012, respectively, and $148 thousand and $201 thousand in compression and gathering fees for the six months ended June 30, 2013 and 2012, respectively.

The Partnership has agreed to provide design, procurement and construction management services for ARP with respect to a pipeline to be located in Lycoming County, Pennsylvania. The total estimated price for the Partnership s services in connection with the project is under $2.5 million.

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NOTE 17 SEGMENT INFORMATION

The Partnership has two reportable segments: Gathering and Processing; and Transportation, Treating and Other (Transportation and Treating). These reportable segments reflect the way the Partnership manages its operations.

The Gathering and Processing segment consists of (1) the Arkoma, SouthTX, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Eagle Ford Shale play in Texas and the Anadarko, Arkoma, and Permian Basins; and (2) the natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering, processing and treating of natural gas.

The Transportation and Treating segment consists of (1) contract gas treating operations located in various shale plays including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford; and (2) the Partnership s 20% interest in the equity income generated by West Texas LPG Pipeline Limited Partnership, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Contract gas treating revenues are primarily derived from monthly lease fees for use of treating facilities. Pipeline revenues are primarily derived from transportation fees.

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

	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Three Months Ended June 30, 2013:				
Revenue:				
Revenues third party[1]	$ 532,435	$ 1,451	$ 26,976	$ 560,862
Revenues affiliates	77			77
Total revenues	532,512	1,451	26,976	560,939
Costs and Expenses:				
Operating costs and expenses	448,663	323		448,986
General and administrative[1] `			12,546	12,546
Other costs			18,370	18,370
Depreciation and amortization	43,997	2,184	202	46,383
Interest expense[1]			22,581	22,581
Total costs and expenses	492,660	2,507	53,699	548,866
Equity income in joint venture	(2,159)	1,687		(472)
Loss on asset disposition	(1,519)			(1,519)
Loss on early extinguishment of debt			(19)	(19)
Income (loss) before tax	36,174	631	(26,742)	10,063
Income tax benefit	28			28
Net income (loss)	$ 36,202	$ 631	$ (26,742)	$ 10,091
Three Months Ended June 30, 2012:				
Revenue:				
Revenues third party[1]	$ 257,253	$	$ 66,739	$ 323,992
Revenues affiliates	122			122
Total revenues	257,375		66,739	324,114
Costs and expenses:				
Operating costs and expenses	209,925	(10)		209,915
General and administrative[1]			10,445	10,445
Other costs	(161)			(161)
Depreciation and amortization	21,712			21,712
Interest expense[1]			9,269	9,269
Total costs and expenses	231,476	(10)	19,714	251,180
Equity income in joint venture		1,917		1,917
Net income	$ 25,899	$ 1,927	$ 47,025	$ 74,851

(1) The Partnership notes derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

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	Gathering and Processing	Transportation and Treating	Corporate and Other	Consolidated
Six Months Ended June 30, 2013:				
Revenue:				
Revenues third party[(1)]	$ 951,042	$ 2,884	$ 14,777	$ 968,703
Revenues affiliates	148			148
Total revenues	951,190	2,884	14,777	968,851
Costs and Expenses:				
Operating costs and expenses	795,718	667		796,385
General and administrative[(1)] `			26,344	26,344
Other costs			18,900	18,900
Depreciation and amortization	73,968	2,452	421	76,841
Interest expense[(1)]			41,267	41,267
Total costs and expenses	869,686	3,119	86,932	959,737
Equity income in joint venture	(2,159)	3,727		1,568
Loss on asset disposition	(1,519)			(1,519)
Loss on early extinguishment of debt			(26,601)	(26,601)
Income (loss) before tax	77,826	3,492	(98,756)	(17,438)
Income tax benefit	37			37
Net income (loss)	$ 77,863	$ 3,492	$ (98,756)	$ (17,401)
Six Months Ended June 30, 2012:				
Revenue:				
Revenues third party[(1)]	$ 562,641	$	$ 53,558	$ 616,199
Revenues affiliates	201			201
Total revenues	562,842		53,558	616,400
Costs and expenses:				
Operating costs and expenses	457,092	73		457,165
General and administrative[(1)]			20,390	20,390
Other costs	(195)			(195)
Depreciation and amortization	42,554			42,554
Interest expense[(1)]			17,977	17,977
Total costs and expenses	499,451	73	38,367	537,891
Equity income in joint venture		2,813		2,813
Net income	$ 63,391	$ 2,740	$ 15,191	$ 81,322

(1) The Partnership notes derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.

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Capital Expenditures:	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Gathering and processing	$ 105,972	$ 65,221	$ 213,594	$ 146,388
Transportation and treating	22		144	
Corporate and other	1,199		1,971	
	$ 107,193	$ 65,221	$ 215,709	$ 146,388

Balance Sheet	June 30, 2013	December 31, 2012
Equity method investment in joint ventures:		
Gathering and processing	$ 145,961	$
Transportation and treating	86,129	86,002
	$ 232,090	$ 86,002
Goodwill:		
Gathering and processing	458,458	292,448
Transportation and treating	43,863	26,837
	$ 502,321	$ 319,285
Total assets:		
Gathering and processing	$ 3,946,025	$ 2,831,639
Transportation and treating	176,811	141,356
Corporate and other	181,338	92,643
	$ 4,304,174	$ 3,065,638

The following table summarizes the Partnership s natural gas and liquids sales by product or service for the periods indicated (in thousands):

	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
Natural gas and liquids sales:				
Natural gas	$ 191,885	$ 69,939	$ 333,369	$ 148,644
NGLs	270,240	149,160	488,071	337,854
Condensate	30,444	21,925	55,009	44,023
Other	(1,339)	(2,223)	(1,371)	(2,495)
Total	$ 491,230	$ 238,801	$ 875,078	$ 528,026

NOTE 18 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements as of June 30, 2013 and December 31, 2012 and for the three and six months ended June 30, 2013 and 2012 include the financial statements of WestOK LLC, WestTX LLC, and Centrahoma. Under the terms of the Senior Notes and the revolving credit facility, WestOK LLC, WestTX LLC and Centrahoma are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the

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Partnership s stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership s consolidated accounts as of June 30, 2013 and December 31, 2012 and for the three and six months ended June 30, 2013 and 2012. For the purpose of the following financial information, the Partnership s investments in its subsidiaries and the guarantor subsidiaries investments in their subsidiaries are presented in accordance with the equity method of accounting (in thousands):

Balance Sheets **June 30, 2013**	**Parent**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Consolidating Adjustments**	**Consolidated**
Assets					
Cash and cash equivalents	$	$ 39,475	$ (18,394)	$	$ 21,081
Accounts receivable affiliates	701,882			(701,882)	
Other current assets	192	128,921	167,340	(1,513)	294,940
Total current assets	702,074	168,396	148,946	(703,395)	316,021
Property, plant and equipment, net		770,868	1,852,210		2,623,078
Intangible assets, net		465,572	104,271		569,843
Goodwill		457,312	45,009		502,321
Equity method investment in joint ventures		232,090			232,090
Long term portion of derivative asset		14,591			14,591
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	3,236,787	1,522,260		(4,759,047)	
Other assets, net	44,384	1,772	74		46,230
Total assets	$ 3,983,245	$ 3,632,861	$ 4,003,438	$ (7,315,370)	$ 4,304,174
Liabilities and Equity					
Accounts payable affiliates	$	$ 476,203	$ 229,246	$ (701,882)	$ 3,567
Other current liabilities	26,007	112,344	162,898		301,249
Total current liabilities	26,007	588,547	392,144	(701,882)	304,816
Long-term debt, less current portion	1,634,894	403			1,635,297
Deferred income taxes, net		35,513			35,513
Other long-term liability	181	206	6,000		6,387
Equity	2,322,163	3,008,192	3,605,294	(6,613,488)	2,322,161
Total liabilities and equity	$ 3,983,245	$ 3,632,861	$ 4,003,438	$ (7,315,370)	$ 4,304,174

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December 31, 2012

Assets					
Cash and cash equivalents	$	$ 157	$ 3,241	$	$ 3,398
Accounts receivable affiliates	921,702			(921,702)	
Other current assets	172	68,144	149,507	(1,146)	216,677
Total current assets	921,874	68,301	152,748	(922,848)	220,075
Property, plant and equipment, net		491,790	1,708,591		2,200,381
Intangible assets, net		101,446	97,914		199,360
Goodwill		278,423	40,862		319,285
Equity method investment in joint venture		86,002			86,002
Long term portion of derivative asset		7,942			7,942
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,832,652	1,880,155		(3,712,807)	
Other assets, net	30,496	1,772	325		32,593
Total assets	$ 2,785,022	$ 2,915,831	$ 3,853,368	$ (6,488,583)	$ 3,065,638
Liabilities and Equity					
Accounts payable affiliates	$	$ 145,436	$ 781,766	$ (921,702)	$ 5,500
Other current liabilities	10,046	61,333	176,640		248,019
Total current liabilities	10,046	206,769	958,406	(921,702)	253,519
Long-term debt, less current portion	1,168,415	604	64		1,169,083
Deferred income taxes, net		30,258			30,258
Other long-term liability	153	217	6,000		6,370
Equity	1,606,408	2,677,983	2,888,898	(5,566,881)	1,606,408
Total liabilities and equity	$ 2,785,022	$ 2,915,831	$ 3,853,368	$ (6,488,583)	$ 3,065,638

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Statements of Operations

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended June 30, 2013					
Total revenues	$	$ 158,014	$ 425,516	$ (22,591)	$ 560,939
Total costs and expenses	(21,332)	(164,950)	(384,580)	21,996	(548,866)
Equity income	29,635	38,654		(68,761)	(472)
Loss on early extinguishment of debt	(19)				(19)
Loss on asset disposition		(1,519)			(1,519)
Income (loss), before tax	8,284	30,199	40,936	(69,356)	10,063
Income tax benefit		28			28
Net income (loss)	8,284	30,227	40,936	(69,356)	10,091
Income attributable to non-controlling interest			(1,810)		(1,810)
Preferred unit imputed dividend effect		(6,729)			(6,729)
Preferred unit dividends		(5,341)			(5,341)
Net income (loss) attributable to common limited partners and the General Partner	$ 8,284	$ 18,157	$ 39,126	$ (69,356)	$ (3,789)
Three Months Ended June 30, 2012					
Total revenues	$	$ 116,851	$ 207,263	$	$ 324,114
Total costs and expenses	(8,480)	(60,452)	(182,248)		(251,180)
Equity income	82,270	26,141		(106,494)	1,917
Net income (loss)	73,790	82,540	25,015	(106,494)	74,851
Income attributable to non-controlling interest			(1,061)		(1,061)
Net income (loss) attributable to common limited partners and the General Partner	73,790	82,540	23,954	(106,494)	73,790
Other comprehensive income adjustment for realized losses on derivatives reclassified to net income	1,108	1,108		(1,108)	1,108
Comprehensive income (loss)	$ 74,898	$ 83,648	$ 23,954	$ (107,602)	$ 74,898

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Statements of Operations

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Six Months Ended June 30, 2013					
Total revenues	$	$ 249,856	$ 760,887	$ (41,892)	$ 968,851
Total costs and expenses	(39,929)	(279,176)	(681,929)	41,297	(959,737)
Equity income	45,951	77,348		(121,731)	1,568
Loss on early extinguishment of debt	(26,601)				(26,601)
Loss on asset disposition		(1,519)			(1,519)
Income (loss), before tax	(20,579)	46,509	78,958	(122,326)	(17,438)
Income tax benefit		37			37
Net income (loss)	(20,579)	46,546	78,958	(122,326)	(17,401)
Income attributable to non-controlling interest			(3,179)		(3,179)
Preferred unit imputed dividend effect		(6,729)			(6,729)
Preferred unit dividends		(5,341)			(5,341)
Net income (loss) attributable to common limited partners and the General Partner	$ (20,579)	$ 34,476	$ 75,779	$ (122,326)	$ (32,650)
Six Months Ended June 30, 2012					
Total revenues	$	$ 165,839	$ 450,561	$	$ 616,400
Total costs and expenses	(16,829)	(130,536)	(390,526)		(537,891)
Equity income	95,554	61,046		(153,787)	2,813
Net income (loss)	78,725	96,349	60,035	(153,787)	81,322
Income attributable to non-controlling interest			(2,597)		(2,597)
Net income (loss) attributable to common limited partners and the General Partner	78,725	96,349	57,438	(153,787)	78,725
Other comprehensive income adjustment for realized losses on derivatives reclassified to net income	2,254	2,254		(2,254)	2,254
Comprehensive income (loss)	$ 80,979	$ 98,603	$ 57,438	$ (156,041)	$ 80,979

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Statements of Cash Flows

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Six Months Ended June 30, 2013					
Net cash provided by (used in):					
Operating activities	$ (371,569)	$ 69,916	$ 86,738	$ 280,636	$ 65,721
Investing activities	(807,215)	(978,215)	(213,535)	782,721	(1,216,244)
Financing activities	1,178,784	947,617	105,162	(1,063,357)	1,168,206
Net change in cash and cash equivalents		39,318	(21,635)		17,683
Cash and cash equivalents, beginning of period		157	3,241		3,398
Cash and cash equivalents, end of period	$	$ 39,475	$ (18,394)	$	$ 21,081
Six Months Ended June 30, 2012					
Net cash provided by (used in):					
Operating activities	$ (77,361)	$ 58,596	$ 75,854	$ 7,442	$ 64,531
Investing activities	(42,215)	71,933	(144,245)	(68,300)	(182,827)
Financing activities	119,576	(130,440)	68,391	60,858	118,385
Net change in cash and cash equivalents		89			89
Cash and cash equivalents, beginning of period		168			168
Cash and cash equivalents, end of period	$	$ 257	$	$	$ 257

NOTE 19 SUBSEQUENT EVENTS

On July 23, 2013, the Partnership declared a cash distribution of $0.62 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2013. The $54.0 million distribution, including $5.9 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2013 to unitholders of record at the close of business on August 7, 2013 (see Note 5).

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 the year ended December 31, 2012. 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.

General

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 thereto appearing elsewhere in this report and with our Annual Report on Form 10-K for the year ended December 31, 2012.

Overview

We are a publicly-traded Delaware limited partnership formed in 1999 whose common units are listed on the New York Stock Exchange under the symbol APL. We are a leading provider of natural gas gathering, processing and treating services in the Anadarko, Arkoma and Permian Basins located in the southwestern and mid-continent regions of the United States; a provider of natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and a provider of NGL transportation services in the southwestern region of the United States.

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Gathering and Processing; and Transportation and Treating.

The Gathering and Processing segment consists of (1) the Arkoma, SouthTX, WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Eagle Ford Shale play in Texas and the Anadarko, Arkoma and Permian Basins; and (2) natural gas gathering assets located in the Barnett Shale play in Texas and the Appalachian Basin in Tennessee. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and the gathering and processing of natural gas.

As of June 30, 2013, our Gathering and Processing operations, own, have interests in and operate fourteen natural gas processing plants with aggregate capacity of approximately 1,490 MMCFD located in Oklahoma and Texas; a gas treating facility located in Oklahoma; and approximately 10,600 miles of active natural gas gathering systems located in Oklahoma, Kansas, Tennessee and Texas. Our gathering systems gather natural gas from oil and natural gas wells and central delivery points and deliver this gas to processing plants, as well as third-party pipelines.

Our Gathering and Processing operations are all located in or near areas of abundant and long-lived natural gas production, including the Golden Trend, Mississippian Limestone and Hugoton field in the Anadarko Basin; the Woodford Shale; the Spraberry Trend, which is an oil play with associated natural gas in the Permian Basin; the Barnett Shale; and the Eagle Ford Shale. Our gathering systems are connected to approximately 8,600 receipt points, consisting primarily of individual well connections and, secondarily, central delivery points, which are linked to multiple wells. We believe we have significant scale in each of our primary service areas. We provide gathering, processing and treating services to the wells connected to our systems, primarily under long-term contracts. As a result of the location and capacity of our gathering, processing and treating assets, we believe we are strategically positioned to capitalize on the drilling activity in our service areas.

Our Transportation and Treating operations consist of (1) seventeen gas treating facilities used to provide contract treating services to natural gas producers located in Arkansas, Louisiana, Oklahoma and Texas; and (2) a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. The contract gas treating operations are located in various shale plays, including the Avalon, Eagle Ford, Granite Wash, Haynesville, Fayetteville and Woodford. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest.

Recent Events

On January 7, 2013, we paid $6.0 million for the first of two contingent payments related to the acquisition of a gas gathering system and related assets in February 2012. We agreed to pay up to an additional $12.0 million, payable in two equal amounts, if certain volumes were achieved on the acquired gathering system within specified periods of time. Sufficient volumes were achieved in December 2012 to meet the required volumes for the first contingent payment.

On February 11, 2013, we issued $650.0 million of 5.875% unsecured senior notes due August 1, 2023 (5.875% Senior Notes) in a private placement transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.3 million and utilized the proceeds to redeem our outstanding 8.75% senior unsecured notes due June 15, 2018 (8.75% Senior Notes) and repay a portion of our outstanding indebtedness under our revolving credit facility (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes).

Prior to issuance of the 5.875% Senior Notes and in anticipation thereof, on January 28, 2013, we commenced a cash tender offer for any and all of our outstanding $365.8 million 8.75% Senior Notes, and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture governing the 8.75% Senior Notes (8.75% Senior Notes Indenture). Approximately $268.4 million aggregate principal amount of the 8.75% Senior Notes (representing approximately 73.4% of the outstanding 8.75% Senior Notes), were validly tendered as of the expiration date of the consent solicitation. In February 2013, we accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture. We also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer.

On March 12, 2013, we paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. We funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

On April 12, 2013, we placed in service a new 200 MMCFD cryogenic processing plant, known as the Driver Plant in our WestTX system in the Permian Basin of Texas, increasing the WestTX system capacity to 455 MMCFD.

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On April 16, 2013, we executed a Class D preferred unit purchase agreement for a private placement of $400.0 million of our Class D convertible preferred units (Class D Preferred Units) to third party investors, at a negotiated price per unit of $29.75 for net proceeds of $397.7 million. We also received a capital contribution from the General Partner of $8.2 million to maintain its 2.0% general partner interest in us. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Class D Preferred Units). We used the proceeds to fund a portion of the purchase price of 100% of the equity interests held by TEAK Midstream, LLC (TEAK) (the TEAK Acquisition) (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Teak Midstream, LLC).

On April 17, 2013, we sold 11,845,000 of our common units in a registered public offering at a price of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. We also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Common Units). We used the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Teak Midstream, LLC).

On April 19, 2013, we entered into an amendment to our revolving credit agreement, which among other changes:

- allowed the TEAK Acquisition to be a Permitted Investment, as defined in the credit agreement;
- did not require the joint venture interests acquired in the TEAK Acquisition to be guarantors;
- permitted the payment of cash distributions, if any, on the Class D Preferred Units so long as we have a pro forma Minimum Liquidity, as defined in the credit agreement, of greater than or equal to $50 million; and
- modified the definition of Consolidated Funded Debt Ratio, Interest Coverage Ratio and Consolidated EBITDA to allow for an Acquisition Period whereby the terms for calculating each of these ratios have been adjusted.

On May 7, 2013, we completed the TEAK Acquisition for $1.0 billion in cash, subject to customary purchase price adjustments, less cash received (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Teak Midstream, LLC).

On May 10, 2013, we issued $400.0 million of the 4.75% unsecured senior notes due November 15, 2021 (4.75% Senior Notes) in a private placement transaction. The 4.75% Senior Notes were issued at par. We received net proceeds of $391.5 million after underwriting commissions and other transactions costs (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes). We utilized the proceeds repay a portion of our outstanding indebtedness under the revolving credit agreement as part of the TEAK acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Teak Midstream, LLC).

Subsequent Events

On July 23, 2013, we declared a cash distribution of $0.62 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2013. The $54.0 million distribution, including $5.9 million to our General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2013 to unitholders of record at the close of business on August 7, 2013 (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Cash Distributions).

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Acquisitions

On May 7, 2013, we completed the TEAK Acquisition. The assets acquired are referenced as the SouthTX system and include the following gas gathering and processing facilities:

- the Silver Oak I plant, which is a 200 MMCFD cryogenic processing facility;
- a second 200 MMCFD cryogenic processing facility, the Silver Oak II plant, scheduled to be placed in service the first quarter of 2014;
- 265 miles of primarily 20-24 inch gathering and residue lines;
- approximately 275 miles of low pressure gathering lines;
- a 75% interest in T2 LaSalle Gathering Company L.L.C., which owns a 62 mile 24 inch gathering line;
- a 50% interest in T2 Eagle Ford Gathering Company L.L.C., which owns a 45 mile 16 inch gathering pipeline and is currently building a 71 mile 24 inch gathering line; and
- a 50% interest in T2 EF Cogeneration Holdings L.L.C., which is building a cogeneration facility.

In December 2012, we acquired 100% of the equity interests held by Cardinal Midstream, LLC (Cardinal) in three wholly-owned subsidiaries for $599.1 million in cash, including purchase price adjustments, less cash received (the Cardinal Acquisition). The assets of these companies represented the majority of the operating assets of Cardinal and include gas gathering, processing and treating facilities in Arkansas, Louisiana, Oklahoma and Texas (which are referenced as the Arkoma system) as follows:

- the Tupelo plant, which is a 120 MMCFD cryogenic processing facility;
- approximately 60 miles of gathering pipeline;
- the East Rockpile treating facility, a 250 GPM amine treating plant;
- a fixed fee contract gas treating business that includes 15 amine treating plants and two propane refrigeration plants; and
- a 60% interest in a joint venture known as Centrahoma Processing, LLC (Centrahoma). The remaining 40% interest is owned by MarkWest Oklahoma Gas Company, LLC, (MarkWest), a wholly-owned subsidiary of MarkWest Energy Partners, L.P. (NYSE: MWE). Centrahoma owns the following assets:

the Coalgate and Atoka plants, which are cryogenic processing facilities with a combined current processing capacity of approximately 100 MMCFD;

the prospective Stonewall plant, for which construction has been approved, with anticipated processing capacity of 120 MMCFD; and

15 miles of NGL pipeline.

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How We Evaluate Our Operations

Our principal revenue is generated from the gathering, processing and treating of natural gas and the sale of natural gas, NGLs and condensate. Our profitability is a function of the difference between the revenues we receive and the costs associated with conducting our operations, including the cost of natural gas, NGLs and condensate we purchase as well as operating and general and administrative costs and the impact of our commodity hedging activities. Because commodity price movements tend to impact both revenues and costs, increases or decreases in our revenues alone are not necessarily indicative of increases or decreases in our profitability. Variables that affect our profitability are:

- the volumes of natural gas we gather, process and treat, which in turn, depend upon the number of wells connected to our gathering systems, the amount of natural gas the wells produce, and the demand for natural gas, NGLs and condensate;

- the price of the natural gas we gather, process and treat, and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent and northeastern areas of the United States;

- the NGL and BTU content of the gas gathered and processed;

- the contract terms with each producer; and

- the efficiency of our gathering systems and processing and treating plants.

Revenue consists of the sale of natural gas, NGLs and condensate; and the fees earned from our gathering, processing and treating 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, NGLs and condensate off delivery points on our systems. Under other agreements, we gather natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Revenue Recognition for further discussion of contractual revenue arrangements).

Our management uses a variety of financial measures and operational measurements other than our GAAP financial statements to analyze our performance. These include: (1) volumes, (2) operating expenses and (3) the following non-GAAP measures gross margin, EBITDA, adjusted EBITDA and distributable cash flow. Our management views these measures as important performance measures of core profitability for our operations and as key components of our internal financial reporting. We believe investors benefit from having access to the same financial measures that our management uses.

Volumes. Our profitability is impacted by our ability to add new sources of natural gas supply to offset the natural decline of existing volumes from natural gas wells that are connected to our gathering, processing and treating systems. This is achieved by connecting new wells and adding new volumes in existing areas of production. Our performance at our plants is also significantly impacted by the quality of the natural gas we process, the NGL content of the natural gas and the plant s recovery capability. In addition, we monitor fuel consumption and losses because they have a significant impact on the gross margin realized from our processing operations.

Operating Expenses. Plant operating, transportation and compression expenses generally include the costs required to operate and maintain our pipelines and processing facilities, including salaries and wages, repair and maintenance expense, ad valorem taxes and other overhead costs.

Gross Margins. We define gross margin as natural gas and liquids sales plus transportation, processing and other fees less purchased product costs, subject to certain non-cash adjustments. Product costs include the cost of natural gas, NGLs and condensate we purchase from third parties. Gross margin, as we define it, does not include plant operating expenses; transportation and compression expenses; and derivative gain (loss) related to undesignated hedges, as movements in gross margin generally do not result in directly correlated movements in these categories.

Gross margin is a non-GAAP measure. The GAAP measure most directly comparable to gross margin is net income. Gross margin is not an alternative to GAAP net income and has important limitations as an analytical tool. Investors should not consider gross margin in isolation or as a substitute for analysis of our results as reported under GAAP. Because gross margin excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of gross margin may not be comparable to gross margin measures of other companies, thereby diminishing its utility.

EBITDA and Adjusted EBITDA. EBITDA represents net income (loss) before interest expense, income taxes, depreciation and amortization. Adjusted EBITDA is calculated by adding to EBITDA other non-cash items such as compensation expenses associated with unit issuances, principally to directors and employees, impairment charges and other cash items such as non-recurring cash derivative early termination expense. The GAAP measure most directly comparable to EBITDA and Adjusted EBITDA is net income. EBITDA and Adjusted EBITDA are not intended to represent cash flow and do not represent the measure of cash available for distribution. Our method of computing Adjusted EBITDA may not be the same method used to compute similar measures reported by other companies. The Adjusted EBITDA calculation is similar to the Consolidated EBITDA calculation utilized within the financial covenants under our credit facility, with the exception that Adjusted EBITDA includes certain non-cash items specifically excluded under our credit facility and excludes the capital expansion add back included in Consolidated EBITDA as defined in the credit facility (see Revolving Credit Facility).

Certain items excluded from EBITDA and Adjusted EBITDA are significant components in understanding and assessing an entity s financial performance, such as cost of capital and historic costs of depreciable assets. We have included information concerning EBITDA and Adjusted EBITDA because they provide investors and management with additional information to better understand our operating performance and are presented solely as a supplemental financial measure. EBITDA and Adjusted EBITDA should not be considered as alternatives to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as indicators of our operating performance or liquidity. The economic substance behind our use of Adjusted EBITDA is to measure the ability of our assets to generate cash sufficient to pay interest costs, support our indebtedness and make distributions to our unit holders.

Distributable Cash Flow. We define distributable cash flow as net income plus tax, depreciation and amortization; amortization of deferred financing costs included in interest expense; and non-cash gain (losses) on derivative contracts, less income attributable to non-controlling interests, preferred unit dividends, maintenance capital expenditures, gain (losses) on asset sales and other non-cash gain (losses).

Distributable cash flow is a significant performance metric used by our management and by external users of our financial statements, such as investors, commercial banks and research analysts, to compare basic cash flows generated by us to the cash distributions we expect to pay our unitholders. Using this metric, management and external users of our financial statements can compute the ratio of distributable cash flow per unit to the declared cash distribution per unit to determine the rate at which the distributable cash flow covers the distribution. Distributable cash flow is also an important financial measure for our unitholders since it serves as an indicator of our success in providing a cash return on investment. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our quarterly distribution rates. Distributable cash flow is also a quantitative standard used throughout the investment community with respect to publicly-traded partnerships because the value of a unit of such an entity is generally determined by the unit s yield, which in turn is based on the amount of cash distributions the entity pays to a unitholder.

The GAAP measure most directly comparable to distributable cash flow is net income. Distributable cash flow should not be considered as an alternative to GAAP net income or GAAP cash flows from operating activities. Distributable cash flow is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. Investors should not consider distributable cash flow in isolation or as a substitute for analysis of our results as reported under GAAP. Because distributable cash flow excludes some, but not all, items that affect net income and is defined differently by different companies in our industry, our definition of distributable cash flow may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

Non-GAAP Financial Measures

The following tables reconcile the non-GAAP financial measurements used by management to their most directly comparable GAAP measures for the three and six months ended June 30, 2013 and 2012 (in thousands):

RECONCILIATION OF GROSS MARGIN

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Net income (loss)	$ 10,091	$ 74,851	$ (17,401)	$ 81,322
Adjustments:				
Derivative gain, net	(27,107)	(67,847)	(15,024)	(55,812)
Other income, net	(2,296)	(2,588)	(5,718)	(5,003)
Operating expenses(1)	43,140	14,651	65,529	28,762
General and administrative expense(2)	12,546	10,445	26,344	20,390
Depreciation and amortization	46,383	21,712	76,841	42,554
Interest	22,581	9,269	41,267	17,977
Income tax benefit	(28)		(37)	
Equity (income) loss in joint ventures	472	(1,917)	(1,568)	(2,813)
Loss on early extinguishment of debt	19		26,601	
Loss on asset sales and other	1,519		1,519	
Non-cash linefill loss(3)	1,339	2,223	1,371	2,495
Gross margin	$ 108,659	$ 60,799	$ 199,724	$ 129,872

(1) Operating expenses include plant operating expenses; transportation and compression expenses; and other costs.
(2) General and administrative includes compensation reimbursement to affiliates.
(3) Represents the non-cash impact of commodity price movements on pipeline linefill.

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RECONCILIATION OF EBITDA, ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net income (loss)	$ 10,091	$ 74,851	$ (17,401)	$ 81,322
Adjustments:				
Interest expense	22,581	9,269	41,267	17,977
Income tax benefit	(28)		(37)	
Depreciation and amortization	46,383	21,712	76,841	42,554
EBITDA	79,027	105,832	100,670	141,853
Adjustments:				
Income attributable to non-controlling interests(1)	(1,810)	(1,061)	(3,179)	(2,597)
Non-controlling interest depreciation, amortization and interest expense(2)	(1,121)		(1,971)	
Equity (income) loss in joint ventures	472	(1,917)	(1,568)	(2,813)
Distributions from joint ventures	1,800	1,800	3,600	3,600
Loss on early extinguishment of debt	19		26,601	
Loss on asset disposition	1,519		1,519	
Non-cash gain on derivatives	(24,263)	(64,741)	(10,544)	(54,045)
Premium expense on derivative instruments	3,745	3,984	7,020	7,736
Unrecognized economic impact of acquisition	1,126		1,126	
Acquisition costs	18,370		18,900	
Non-cash compensation	3,436	2,940	7,820	3,918
Non-cash line fill loss(3)	1,339	2,223	1,371	2,495
Minimum volume adjustment(4)	2,653		2,653	
Adjusted EBITDA	86,312	49,060	154,018	100,147
Adjustments:				
Interest expense	(22,581)	(9,269)	(41,267)	(17,977)
Amortization of deferred finance costs	1,739	1,130	3,283	2,295
Premium expense on derivative instruments	(3,745)	(3,984)	(7,020)	(7,736)
Other costs		(161)		(195)
Maintenance capital(5)	(3,713)	(4,000)	(7,527)	(8,510)
Distributable Cash Flow	$ 58,012	$ 32,776	$ 101,487	$ 68,024

(1) Represents Anadarko Petroleum Corporation s (Anadarko NYSE: APC) non-controlling interest in the operating results of Atlas Pipeline Mid-Continent WestOk, LLC (WestOK) and Atlas Pipeline Mid-Continent WestTex, LLC (WestTX); and MarkWest s non-controlling interest in Centrahoma.

(2) Represents the depreciation, amortization and interest expense included in income attributable to non-controlling interest for MarkWest s interest in Centrahoma.

(3) Represents the non-cash impact of commodity price movements on pipeline linefill.

(4) Represents minimum volume adjustments on certain producer throughput contracts.

(5) Net of non-controlling interest maintenance capital of $135 thousand and $176 thousand for the three and six months ended June 30, 2013, respectively.

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Results of Operations

The following table illustrates selected pricing before the effect of derivatives and volumetric information for the periods indicated:

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Percent Change	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Percent Change
Pricing:						
Weighted Average Market Prices:						
NGL price per gallon Conway hub	$ 0.75	$ 0.70	7.1%	$ 0.79	$ 0.82	(3.7)%
NGL price per gallon Mt. Belvieu hub	0.80	0.94	(14.9)%	0.83	1.06	(21.7)%
Natural gas sales ($/Mcf):						
Velma	3.88	2.04	90.2%	3.53	2.29	54.1%
WestOK	3.84	2.09	83.7%	3.54	2.30	53.9%
WestTX	3.74	1.85	102.2%	3.45	2.18	58.3%
Weighted Average	3.82	2.01	90.0%	3.59	2.26	58.8%
NGL sales ($/gallon):						
Arkoma	0.66			0.69		
Velma	0.72	0.71	1.4%	0.75	0.82	(8.5)%
WestOK	0.96	0.79	21.5%	0.97	0.85	14.1%
WestTX	0.86	0.88	(2.3)%	0.89	1.03	(13.6)%
Weighted Average	0.84	0.80	5.0%	0.84	0.92	(8.7)%
Condensate sales ($/barrel):						
Arkoma	81.18			84.79		
Velma	93.32	93.69	(0.4)%	93.36	98.52	(5.2)%
WestOK	84.53	85.41	(1.0)%	84.10	90.00	(6.6)%
WestTX	93.96	86.17	9.0%	91.97	91.11	0.9%
Weighted Average	89.15	87.00	2.5%	88.09	91.95	(4.2)%

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Percent Change	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Percent Change
Operating data:						
Arkoma system[(1)]:						
Gathered gas volume (MCFD)	283,238			272,047		
Processed gas volume (MCFD)	202,113			201,709		
Residue gas volume (MCFD)	208,163			208,004		
NGL volume (BPD)	25,590			22,736		
Condensate volume (BPD)	152			156		
Velma system:						
Gathered gas volume (MCFD)	139,736	136,553	2.3%	135,276	132,888	1.8%
Processed gas volume (MCFD)	132,699	129,070	2.8%	129,058	125,987	2.4%
Residue gas volume (MCFD)	111,487	106,424	4.8%	106,888	103,380	3.4%
NGL volume (BPD)	16,201	14,220	13.9%	15,105	13,931	8.4%
Condensate volume (BPD)	384	434	(11.5)%	394	499	(21.0)%
WestOK system:						
Gathered gas volume (MCFD)	506,487	336,377	50.6%	479,577	315,787	51.9%
Processed gas volume (MCFD)	483,504	315,753	53.1%	454,628	297,529	52.8%
Residue gas volume (MCFD)	444,670	291,225	52.7%	420,815	271,582	54.9%
NGL volume (BPD)	22,233	14,379	54.6%	19,258	14,220	35.4%
Condensate volume (BPD)	1,949	1,209	61.2%	1,959	1,307	49.9%
SouthTX system:						
Gathered gas volume (MCFD)	122,245			122,245		
Processed gas volume (MCFD)	121,338			121,338		
Residue gas volume (MCFD)	96,606			96,606		
NGL volume (BPD)	15,041			15,041		
Condensate volume (BPD)	65			65		
WestTX system[(1)]:						
Gathered gas volume (MCFD)	352,865	267,395	32.0%	332,829	256,867	29.6%
Processed gas volume (MCFD)	313,504	236,213	32.7%	297,220	233,359	27.4%
Residue gas volume (MCFD)	229,777	164,593	39.6%	219,889	162,308	35.5%
NGL volume (BPD)	39,901	32,755	21.8%	36,591	32,928	11.1%
Condensate volume (BPD)	1,993	1,941	2.7%	1,516	1,440	5.3%
Barnett system:						
Average throughput volumes (MCFD)	20,081	23,988	(16.3)%	20,737	23,988	(13.6)%
Tennessee system:						
Average throughput volumes (MCFD)	8,166	8,348	(2.2)%	8,826	8,286	6.5%
WTLPG system[(1)]:						
Average NGL volumes (BPD)	252,886	243,708	3.8%	248,779	243,013	2.4%

(1) Operating data for Arkoma, WestTX and WTLPG represent 100% of operating activity for the respective systems. Arkoma gathered volumes include volumes gathered by MarkWest and processed through the Arkoma facilities.

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Three Months Ended June 30, 2013 Compared to Three Months Ended June 30, 2012

The following table and discussion is a summary of our consolidated results of operations for the three months ended June 30, 2013 and 2012 (in thousands):

	Three Months Ended June 30,			Percent
	2013	2012	Variance	Change
Gross margin[1]				
Natural gas and liquids sales	$ 491,230	$ 238,801	$ 252,429	105.7%
Transportation, processing and other fees	40,306	14,878	25,428	170.9%
Less: non-cash line fill loss[2]	(1,339)	(2,223)	884	39.8%
Less: natural gas and liquids cost of sales	424,216	195,103	229,113	117.4%
Gross margin	108,659	60,799	47,860	78.7%
Expenses:				
Operating expenses	24,770	14,812	9,958	67.2%
General and administrative[3]	12,546	10,445	2,101	20.1%
Other costs	18,370	(161)	18,531	11,509.9%
Depreciation and amortization	46,383	21,712	24,671	113.6%
Interest expense	22,581	9,269	13,312	143.6%
Total expenses	124,650	56,077	68,573	122.3%
Other income items:				
Derivative income, net	27,107	67,847	(40,740)	(60.0)%
Other income, net	2,296	2,588	(292)	(11.3)%
Non-cash line fill loss[2]	(1,339)	(2,223)	884	39.8%
Equity income (loss) in joint ventures	(472)	1,917	(2,389)	(124.6)%
Loss on asset disposition	(1,519)		(1,519)	(100.0)%
Loss on early extinguishment of debt	(19)		(19)	(100.0)%
Income tax benefit	28		28	100.0%
Income attributable to non-controlling interests[4]	(1,810)	(1,061)	(749)	(70.6)%
Preferred unit imputed dividend effect	(6,729)		(6,729)	(100.0)%
Preferred unit dividends	(5,341)		(5,341)	(100.0)%
Net income (loss) attributable to common limited partners and General Partner	$ (3,789)	$ 73,790	$ (77,579)	(105.1)%
Non-GAAP financial data:				
EBITDA[1]	$ 79,027	$ 105,832	$ (26,805)	(25.3)%
Adjusted EBITDA[1]	86,312	49,060	37,252	75.9%
Distributable cash flow[1]	58,012	32,776	25,236	77.0%

(1) Gross Margin, EBITDA, Adjusted EBITDA and Distributable cash flow are non-GAAP financial measures (see How We Evaluate Our Operations and Non-GAAP Financial Measures).

(2) Includes the non-cash impact of commodity price movements on pipeline linefill.

(3) General and administrative also includes any compensation reimbursement to affiliates.

(4) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest s non-controlling interest in the operating results of Centrahoma.

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Gross margin:

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the three months ended June 30, 2013 increased primarily due to higher production volumes, including the new volumes from the Arkoma system due to the Cardinal Acquisition and from the SouthTX system due to the TEAK Acquisition, partially offset by lower commodity prices.

Volumes on the Velma system for the three months ended June 30, 2013 approximated the prior year period volumes.

Volumes on the WestOK system increased for the three months ended June 30, 2013 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand; and the start-up of the Waynoka II plant.

WestTX system gathering and processing volumes for the three months ended June 30, 2013 increased compared to the prior year period due to the startup of our Driver Plant in April 2013 (see Recent Events) and due to increased volumes from Pioneer Natural Resources Company (NYSE: PXD) as a result of their continued drilling program.

Transportation, processing and other fees for the three months ended June 30, 2013 increased primarily due to $11.5 million in additional fee-based revenues generated on the Arkoma systems due to the Cardinal Acquisition (see Acquisitions); $5.5 million in additional fee-based revenues generated on the SouthTX systems due to the TEAK Acquisition (see Acquisitions); and due to increased processing fee revenue of $5.2 million on the WestOK system related to the increased volumes gathered on the systems.

Expenses:

Operating expenses, comprised primarily of plant operating expenses and transportation and compression expenses, for the three months ended June 30, 2013 increased mainly due to $4.2 million in additional expenses from the Arkoma systems and gas treating facilities acquired in the Cardinal Acquisition (see Acquisitions); a $3.0 million increase on the WestOK system primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin ; $1.1 million in additional expenses from the SouthTX systems acquired in the TEAK Acquisition (see Acquisitions); and a $1.0 million increase on the WestTX system primarily due to the start-up of the Driver Plant (see Recent Events).

General and administrative expense, including amounts reimbursed to affiliates, increased for the three months ended June 30, 2013 mainly due to increased expenses related to the Cardinal and TEAK Acquisitions (see Acquisitions); and due to $0.5 million of additional expenses in share-based compensation related to phantom units granted to employees (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 15).

Other costs for the three months ended June 30, 2013 increased mainly due to acquisition costs related to the TEAK Acquisition, which were recorded in the current year period (see Acquisitions).

Depreciation and amortization expense for the three months ended June 30, 2013 increased primarily due to $15.8 million additional expense related to assets acquired in the Cardinal Acquisition (see Acquisitions); $4.3 million additional expense related to assets acquired in the TEAK Acquisition (see Acquisitions); and due to growth capital expenditures incurred subsequent to June 30, 2012.

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Interest expense for the three months ended June 30, 2013 increased primarily due to $9.5 million additional interest related to the 5.875% Senior Notes; $8.1 million increase in interest expense associated with the 6.625% unsecured senior notes due 2020 (6.625% Senior Notes) and $2.6 million additional interest related to the 4.75% Senior Notes, partially offset by $7.8 million reduced interest on the 8.75% Senior Notes. The increase in the interest on the 6.625% Senior Notes, the 5.875% Senior Notes and the 4.75% Senior Notes is due to their issuance after June 30, 2012 (see Senior Notes). The decrease in the interest for the 8.75% Senior Notes is due to their redemption prior to the three months ended June 30, 2013 (see Senior Notes).

Other income items:

Derivative gain, net for the three months ended June 30, 2013 had a $39.9 million unfavorable variance on the fair value revaluation of commodity derivative contracts in the current period compared to the prior year period mainly due to a $64.2 million gain in the prior year period due to a $0.31 per gallon reduction in NGL forward curve prices during the three months ended June 30, 2012, partially offset by a $24.3 million gain in the current year period due to a $0.12 per gallon reduction in NGL forward curve prices during the three months ended June 30, 2013. While we utilize either quoted market prices or observable market data to calculate the fair value of natural gas and crude oil derivatives, valuations of NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGLs for similar geographic locations, and valuations of NGL options are based on forward price curves developed by third-party financial institutions. The use of unobservable market data for NGL fixed price swaps and NGL options has no impact on the settlement of these derivatives. However, a change in management s estimated fair values for these derivatives could impact net income, although it would have no impact on liquidity or capital resources (see Item 1: Notes to Consolidated Financial Statements (Unaudited) Note 11 for further discussion of derivative instrument valuations). We recognized a $17.8 million and $51.5 million mark-to-market gain on derivatives that were valued based upon unobservable inputs for the three months ended June 30, 2013 and 2012, respectively. We enter into derivative instruments solely 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 Item 3: Quantitative and Qualitative Disclosures About Market Risk.

Non-cash line fill loss had a favorable variance for the three months ended June 30, 2013 compared to the prior year period primarily due to a NGL prices reducing more in the prior year period than the current year period.

Equity income in joint ventures decreased for the three months ended June 30, 2013 primarily due to a $2.2 million loss in the current period from the SouthTX equity method investments. The T2 LaSalle and T2 Eagle Ford joint ventures are structured to earn revenues equal to their operating costs, exclusive of depreciation expense. The loss primarily represents depreciation expense and timing of recovery of other expenses.

Loss on asset disposition in the current year period pertained to management s decision to not pursue a project to lay pipe in an area where acquired rights of way had expired in the Velma area.

Income tax benefit for the three months ended June 30, 2013 represents the accrued income tax related to the income earned on APL Arkoma, Inc., which was acquired as part of the Cardinal Acquisition (see Acquisitions).

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Income attributable to non-controlling interests increased primarily due to Anadarko s non-controlling interest in higher net income for the WestOK and WestTX joint ventures. The increase in net income of the WestOK and WestTX joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Preferred unit imputed dividend effect for the current period represents the accretion of the beneficial conversion discount of the Class D Preferred Units (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Preferred Units).

Preferred unit dividends for the current period represent the distributions to the Class D Preferred Units, which have been declared. For the current period these distributions are paid in kind (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Preferred Units).

Non-GAAP financial data:

EBITDA was lower for the three months ended June 30, 2013 compared to the prior year period mainly due to the unfavorable variance on the derivative gain as discussed above in Other income items, combined with higher operating expenses and other costs as discussed above in Expenses; partially offset by improved gross margin as discussed above in Gross Margin.

Adjusted EBITDA had a favorable variance for the three months ended June 30, 2013 compared to the prior year period mainly due to the favorable gross margin variance, as discussed above in Gross margin , partially offset by higher operating expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the three months ended June 30, 2013 compared to the prior year period mainly due to the favorable Adjusted EBITDA variance, as discussed above, partially offset by higher interest expense as discussed above in Expenses.

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Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The following table and discussion is a summary of our consolidated results of operations for the six months ended June 30, 2013 and 2012 (in thousands):

	Six Months Ended June 30, 2013	2012	Variance	Percent Change
Gross margin[1]				
Natural gas and liquids sales	$ 875,078	$ 528,026	$ 347,052	65.7%
Transportation, processing and other fees	73,031	27,559	45,472	165.0%
Less: non-cash line fill loss[2]	(1,371)	(2,495)	1,124	45.1%
Less: natural gas and liquids cost of sales	749,756	428,208	321,548	75.1%
Gross margin	199,724	129,872	69,852	53.8%
Expenses:				
Operating expenses	46,629	28,957	17,672	61.0%
General and administrative[3]	26,344	20,390	5,954	29.2%
Other costs	18,900	(195)	19,095	9,792.3%
Depreciation and amortization	76,841	42,554	34,287	80.6%
Interest expense	41,267	17,977	23,290	129.6%
Total expenses	209,981	109,683	100,298	91.4%
Other income items:				
Derivative income, net	15,024	55,812	(40,788)	(73.1)%
Other income, net	5,718	5,003	715	14.3%
Non-cash line fill loss[2]	(1,371)	(2,495)	1,124	45.1%
Equity income in joint ventures	1,568	2,813	(1,245)	(44.3)%
Loss on asset disposition	(1,519)		(1,519)	(100.0)%
Loss on early extinguishment of debt	(26,601)		(26,601)	(100.0)%
Income tax benefit	37		37	100.0%
Income attributable to non-controlling interests[4]	(3,179)	(2,597)	(582)	(22.4)%
Preferred unit imputed dividend effect	(6,729)		(6,729)	(100.0)%
Preferred unit dividends	(5,341)		(5,341)	(100.0)%
Net income (loss) attributable to common limited partners and General Partner	$ (32,650)	$ 78,725	$ (111,375)	(141.5)%
Non-GAAP financial data:				
EBITDA[1]	$ 100,670	$ 141,853	$ (41,183)	(29.0)%
Adjusted EBITDA[1]	154,018	100,147	53,871	53.8%
Distributable cash flow[1]	101,487	68,024	33,463	49.2%

(1) Gross Margin, EBITDA, Adjusted EBITDA and Distributable cash flow are non-GAAP financial measures (see How We Evaluate Our Operations and Non-GAAP Financial Measures).
(2) Includes the non-cash impact of commodity price movements on pipeline linefill.
(3) General and administrative also includes any compensation reimbursement to affiliates.
(4) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems and MarkWest s non-controlling interest in the operating results of Centrahoma.

Gross margin:

Gross margin from natural gas and liquids sales and the related natural gas and liquids cost of sales for the six months ended June 30, 2013 increased primarily due to higher production volumes, including the new volumes from the Arkoma system due to the Cardinal Acquisition and from the SouthTX system due to the TEAK Acquisition, partially offset by lower commodity prices.

Volumes on the Velma system for the six months ended June 30, 2013 approximated the prior year period volumes.

Volumes on the WestOK system increased for the six months ended June 30, 2013 compared to the prior year primarily due to increased production on the gathering systems, which continue to be expanded to meet producer demand; and the start-up of the Waynoka II plant.

WestTX system gathering and processing volumes for the six months ended June 30, 2013 increased compared to the prior year period due to increased volumes from Pioneer Natural Resources Company (NYSE: PXD) as a result of their continued drilling program; and the start-up of the Driver plant (see Recent Events).

Transportation, processing and other fees for the six months ended June 30, 2013 increased primarily due to $25.9 million in additional fee-based revenues generated on the Arkoma systems acquired in the Cardinal Acquisition (see Acquisitions); increased processing fee revenue of $10.6 million on the WestOK system related to the increased volumes gathered on the systems; and $5.5 million in additional fee-based revenues generated on the SouthTX system acquired in the TEAK Acquisition (see Acquisitions).

Expenses:

Operating expenses, comprised primarily of plant operating expenses and transportation and compression expenses, for the six months ended June 30, 2013 increased mainly due to $7.7 million in additional expenses from the Arkoma systems acquired in the Cardinal Acquisition (see Acquisitions); a $5.8 million increase on the WestOK system primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin ; and $1.1 million in additional expenses from the SouthTX systems acquired in the TEAK Acquisition (see Acquisitions).

General and administrative expense, including amounts reimbursed to affiliates, increased for the six months ended June 30, 2013 mainly due to a $3.9 million increase in share-based compensation related to phantom units granted to employees (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 15) and increased expenses related to the TEAK Acquisition (see Acquisitions).

Other costs for the six months ended June 30, 2013 increased mainly due to $18.2 million in acquisition costs related to the TEAK Acquisition and $0.7 million in acquisition costs related to the Cardinal Acquisition, which were recorded in the current year period (see Acquisitions).

Depreciation and amortization expense for the six months ended June 30, 2013 increased primarily due to $21.4 million additional expense related to assets acquired in the Cardinal Acquisition; $4.3 million additional expense related to assets acquired in the TEAK Acquisition (see Acquisitions) and due to growth capital expenditures incurred subsequent to June 30, 2012.

Interest expense for the six months ended June 30, 2013 increased primarily due to a $16.3 million increase in interest expense associated with 6.625% Senior Notes; $14.9 million additional interest related to the 5.875% Senior Notes; and $2.6 million additional interest related to the 4.75% Senior Notes; partially offset by $11.4 million reduced interest on the 8.75% Senior Notes. The increase in the interest on the 6.625% Senior Notes, the 5.875% Senior Notes and the 4.75% Senior Notes is due to their issuance after June 30, 2012 (see Senior Notes). The decrease in the interest for the 8.75% Senior Notes is due to their redemption during the six months ended June 30, 2013 (see Senior Notes).

Other income items:

Derivative gain, net for the six months ended June 30, 2013 had a $42.3 million unfavorable variance on the fair value revaluation of commodity derivative contracts in the current period compared to the prior year period, due to the NGL forward curve prices falling more during the prior year period. We recognized a $15.4 million and $44.4 million mark-to-market loss on derivatives that were valued based upon unobservable inputs for the six months ended June 30, 2013 and 2012, respectively.

Other income, net for the six months ended June 30, 2013 had a favorable variance primarily due to a $1.0 million settlement of business interruption insurance related to a loss of revenue in our WestOK system in May 2011 due to storm damage at the Chester plant.

Non-cash line fill loss had a favorable variance for the six months ended June 30, 2013 compared to the prior year period primarily due to the settlement of line fill on the Velma system during the prior year period.

Equity income in joint ventures decreased for the six months ended June 30, 2013 primarily due to a $2.2 million loss in the current period from the SouthTX equity method investments. The T2 LaSalle and T2 Eagle Ford joint ventures are structured to earn revenues equal to their operating costs, exclusive of depreciation expense. The loss primarily represents depreciation expense and timing of recovery of other expenses.

Loss on asset disposition in the current year period pertained to management s decision to not pursue a project to lay pipe in an area where acquired rights of way had expired in the Velma area.

Loss on early extinguishment of debt for the six months ended June 30, 2013 represents $17.5 million premiums paid; $8.0 million consent payment made; and $5.3 million write off of deferred financing costs, offset by $4.2 million recognition of unamortized premium related to the redemption of the 8.75% Senior Notes (see Senior Notes).

Income tax benefit for the six months ended June 30, 2013 represents the accrued income tax related to the income earned on APL Arkoma, Inc., which was acquired as part of the Cardinal Acquisition (see Acquisitions).

Income attributable to non-controlling interests increased primarily due to Anadarko s non-controlling interest in higher net income for the WestOK and WestTX joint ventures. The increase in net income of the WestOK and WestTX joint ventures was principally due to higher gross margins on the sale of commodities, resulting from higher volumes.

Preferred unit imputed dividend effect for the current period represents the accretion of the beneficial conversion discount of the Class D Preferred Units (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Preferred Units).

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Preferred unit dividends for the current period represent the distributions to the Class D Preferred Units, which have been declared. For the current period these distributions are paid in kind (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Preferred Units).

Non-GAAP financial data:

EBITDA was lower for the six months ended June 30, 2013 compared to the prior year period mainly due the unfavorable variance on the derivative gain and the loss on early extinguishment of debt recognized during the six months ended June 30, 2013, as discussed above in Other income items, combined with higher other costs and operating expenses as discussed above in Expenses ; partially offset by improved gross margin as discussed above in Gross Margin.

Adjusted EBITDA had a favorable variance for the six months ended June 30, 2013 compared to the prior year period mainly due to the favorable gross margin variance, as discussed above in Gross margin , partially offset by higher operating expenses as discussed above in Expenses.

Distributable cash flow had a favorable variance for the six months ended June 30, 2013 compared to the prior year period mainly due to the favorable Adjusted EBITDA variance, as discussed above, partially offset by higher interest expense as discussed above in Expenses.

Liquidity and Capital Resources

Our primary sources of liquidity are cash generated from operations and borrowings under our revolving 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 capital raising; and
- debt principal payments through operating cash flows and refinancings as they become due, or by the issuance of additional limited partner units or asset sales.

At June 30, 2013, we had $80.0 million outstanding borrowings under our $600.0 million senior secured revolving credit facility and $0.4 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with $519.6 million of remaining committed capacity under the revolving credit facility, (see Revolving Credit Facility). We were in compliance with the credit facility s covenants at June 30, 2013. We had a working capital surplus of $11.2 million at June 30, 2013 compared with a $33.4 million working capital deficit at December 31, 2012. We believe we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash flows. We may need to supplement our cash generation with proceeds from financing activities, including borrowings under our revolving credit facility and other borrowings, the issuance of additional limited partner units and sales of our assets.

Instability in the financial markets, as a result of recession or otherwise, may cause volatility in the markets and may impact the availability of funds from those markets. This may affect our ability to

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raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flows from operations and our revolving credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain additional capital will be available to the extent required and on acceptable terms.

Cash Flows Six Months Ended June 30, 2013 Compared to Six Months Ended June 30, 2012

The following table details the cash flow changes between the six months ended June 30, 2013 and 2012 (in thousands):

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012	Variance	Percent Change
Net cash provided by (used in):				
Operating activities	$ 65,721	$ 64,531	$ 1,190	1.8%
Investing activities	(1,216,244)	(182,827)	(1,033,417)	(565.2)%
Financing activities	1,168,206	118,385	1,049,821	886.8%
Net change in cash and cash equivalents	$ 17,683	$ 89	$ 17,594	

Net cash provided by operating activities for the six months ended June 30, 2013 increased compared to the prior year period due to a $9.4 million increase in net earnings from continuing operations excluding non-cash charges and an $8.2 million favorable variance in the change in working capital. The increase in net earnings from continuing operations excluding non-cash charges is primarily due to increased gross margins from the sale of natural gas and NGLs partially offset by higher operating and interest expenses (see Results of Operations). The change in working capital is primarily due to a $15.5 million increase in accrued interest primarily related to the issuance of our 6.625% Senior Notes, 5.875% Senior Notes, and 4.75% Senior Notes (see Senior Notes), partially offset by a net increase in working capital due to the increased gross margins.

Net cash used in investing activities for the six months ended June 30, 2013 increased compared to the prior year period mainly due to the $1.0 billion Teak Acquisition (see Acquisitions) and $69.3 million increase in capital expenditures in the current year period compared to the prior year period (see further discussion of capital expenditures under Capital Requirements); partially offset by $36.7 million cash paid for acquisition of assets in the prior year period.

Net cash provided by financing activities for the six months ended June 30, 2013 increased compared to the prior year period mainly due to (i) $637.3 million provided by the issuance of the 5.875% Senior Notes in the current period; (ii) $391.5 million provided by the issuance of the 4.75% Senior Notes (see Senior Notes); (iii) $397.7 million provided by the issuance of Class D Preferred Units (see Preferred Unit Offerings); and (iv) $388.4 million provided by the issuance of common units (see Common Unit Offerings); partially offset by the $391.4 million redemption of the 8.75% Senior Notes, including the cost of early retirement of debt; $213.0 million used in the current period to reduce outstanding borrowings on the revolving credit facility; and $188.5 million in additional borrowings on our revolving credit facility in the prior year period.

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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,	
	2013	2012	2013	2012
Expansion capital expenditures	$ 103,345	$ 61,221	$ 208,006	$ 137,878
Maintenance capital expenditures	3,848	4,000	7,703	8,510
Total	$ 107,193	$ 65,221	$ 215,709	$ 146,388

Expansion capital expenditures increased for the three and six months ended June 30, 2013 primarily due to the completion of the Driver Plant within WestTX in April 2013 (see Recent Events) and construction costs for the Stonewall Plant within Arkoma and the Silver Oak II Plant in SouthTX. As of June 30, 2013, we had approved additional expenditures of approximately $390.1 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately $178.0 million purchase commitments had been made. We expect to fund these projects through operating cash flows and borrowings under our existing revolving credit facility.

Partnership Distributions

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders (subject to the rights of any other class or series of our securities with the right to share in our cash distributions) and to 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 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 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 2.0% 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 2.0% of the aggregate amount of cash being distributed. Our General Partner, holder of all our incentive distribution rights, has agreed to allocate up to $3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial $7.0 million of incentive distribution rights per quarter. Incentive distributions of $3.0 million and $1.6 million were paid during the three months ended June 30, 2013 and 2012, respectively, and $5.3 million and $3.0 million were paid during the six months ended June 30, 2013 and 2012, respectively.

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Off Balance Sheet Arrangements

As of June 30, 2013, our off balance sheet arrangements include our letters of credit, issued under the provisions of our revolving credit facility, totaling $0.4 million. These are in place to support various performance obligations as required by (1) statutes within the regulatory jurisdictions where we operate, (2) surety and (3) counterparty support.

We have certain long-term unconditional purchase obligations and commitments, primarily throughput contracts. These agreements provide transportation services to be used in the ordinary course of our operations.

Common Equity Offerings

In April 2013, we sold 11,845,000 of our common units at a price to the public of $34.00 per unit, yielding net proceeds of $388.4 million after underwriting commissions and expenses. We also received a capital contribution from the General Partner of $8.3 million to maintain its 2.0% general partnership interest (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Common Units). We used the proceeds from this offering to fund a portion of the purchase price of the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Teak Midstream, LLC).

We have an equity distribution program with Citigroup, through which we may offer and sell common units having an aggregate value of up to $150.0 million. Such sales will be at market prices prevailing at the time of the sale. There will be no specific date on which the offering will end and there will be no minimum purchase requirements. During the three and six months ended June 30, 2013, we issued 642,495 and 1,090,280 common units, respectively, under the equity distribution program for net proceeds of $24.5 million and $38.9 million, respectively, net of $0.5 million and $0.8 million, respectively, in commissions paid to Citigroup. We also received capital contributions from the General Partner of $0.5 million and $0.8 million during the three and six months ended June 30, 2013, respectively, to maintain its 2.0% general partner interest in us. The net proceeds from the common unit offerings were utilized for general partnership purposes. As of June 30, 2013, we had $101.3 million remaining dollar capacity under the equity distribution program (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Common Units).

Preferred Unit Offerings

On May 7, 2013 we completed the private placement of $400.0 million of our Class D Preferred Units to third party investors, at a negotiated price per unit of $29.75 for net proceeds of $397.7 million pursuant to the Class D Preferred Unit Purchase Agreement. The Class D Preferred Units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended. We also received a capital contribution from the General Partner of $8.2 million to maintain its 2.0% general partner interest in us (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 5 Class D Preferred Units). We used the proceeds to fund a portion of the purchase price of the TEAK Acquisition (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 3 Teak Midstream, LLC).

Revolving Credit Facility

At June 30, 2013, we had a $600.0 million senior secured revolving credit facility with a syndicate of banks, which matures in May 2017. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or

(c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for borrowings on the revolving credit facility, at June 30, 2013, was 3.2%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.4 million was outstanding at June 30, 2013. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

On April 19, 2013, we entered into an amendment to our credit agreement, which among other changes, allowed the TEAK Acquisition to be a permitted investment and did not require the joint venture interests acquired in the TEAK Acquisition to be guarantors (see Recent Events).

Borrowings under the revolving credit facility are secured by a lien on and security interest in all our property and that of our subsidiaries, except for the assets owned by the WestOK, WestTX and Centrahoma joint ventures and their respective subsidiaries. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including covenants to maintain specified financial ratios, 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 also unable to borrow under our revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute working capital borrowings pursuant to our partnership agreement.

The events that constitute an event of default for our revolving credit facility include payment defaults, breaches of representations or covenants contained in the credit agreement, adverse judgments against us in excess of a specified amount, and a change of control of our General Partner. As of June 30, 2013, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At June 30, 2013, we had $500.0 million principal outstanding of 6.625% Senior Notes, $650.0 million principal outstanding of 5.875% Senior Notes, and $400.0 million principal outstanding of 4.75% Senior Notes (together with the 6.625% Senior Notes and 5.875% Senior Notes, the Senior Notes).

The 6.625% Senior Notes are presented combined with a net $4.9 million unamortized premium as of June 30, 2013. Interest on the 6.625% Senior Notes is payable semi-annually in arrears on April 1 and October 1. The 6.625% Senior Notes are redeemable at any time after October 1, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 13-Senior Notes).

On February 11, 2013, we issued $650.0 million of the 5.875% Senior Notes in a private transaction. The 5.875% Senior Notes were issued at par. We received net proceeds of $637.3 million after underwriting commissions and other transactions costs and utilized the proceeds to redeem the 8.75% Senior Notes and repay a portion of the outstanding indebtedness under the revolving credit agreement. Interest on the 5.875% Senior Notes is payable semi-annually in arrears on February 1 and August 1. The 5.875% Senior Notes are redeemable at any time after February 1, 2018, at certain redemption prices, together with accrued and unpaid interest to the date of redemption (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes).

On January 28, 2013, we commenced a cash tender offer for any and all of our outstanding 8.75% Senior Notes and a solicitation of consents to eliminate most of the restrictive covenants and certain of the events of default contained in the indenture 8.75% Senior Notes Indenture. Approximately $268.4

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million aggregate principal amount of the 8.75% Senior Notes, were validly tendered as of the expiration date of the consent solicitation. In February 2013, we accepted for purchase all 8.75% Senior Notes validly tendered as of the expiration of the consent solicitation and paid $291.4 million to redeem the $268.4 million principal plus $11.2 million make-whole premium, $3.7 million accrued interest and $8.0 million consent payment. We entered into a supplemental indenture amending and supplementing the 8.75% Senior Notes Indenture. We also issued a notice to redeem all the 8.75% Senior Notes not purchased in connection with the tender offer.

On March 12, 2013, we paid $105.6 million to redeem the remaining $97.3 million outstanding 8.75% Senior Notes plus a $6.3 million make-whole premium and $2.0 million in accrued interest. We funded the redemption with a portion of the net proceeds from the issuance of the 5.875% Senior Notes.

On May 10, 2013, we issued $400.0 million of the 4.75% Senior Notes in a private placement transaction. The 4.75% Senior Notes were issued at par. We received net proceeds of $391.5 million after underwriting commissions and other transactions costs and utilized the proceeds repay a portion of the outstanding indebtedness under the revolving credit agreement as part of the TEAK Acquisition. Interest on the 4.75% Senior Notes is payable semi-annually in arrears on May 15 and November 15. The 4.75% Senior Notes are due on November 15, 2021 and are redeemable any time after March 15, 2016, at certain redemption prices, together with accrued and unpaid interest to the date of redemption (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 13 Senior Notes).

The Senior Notes are 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 the revolving credit facility.

Indentures governing the Senior Notes 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 our assets. We were in compliance with these covenants as of June 30, 2013

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with GAAP 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 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 subject to such estimates and assumptions include revenue and expense accruals, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. Discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2. In addition to estimates discussed below, discussion of the potential impact of a change in critical accounting estimates is included within our Annual Report on Form 10-K for the year ended December 31, 2012.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Derivative Instruments Our derivative financial instruments are recorded at fair value in the consolidated balance sheets. Changes in fair value and settlements are reflected in our earnings in the consolidated statements of operations as gains and losses related to NGLs sales, interest expense and/or derivative loss, net. (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 10 for further discussion)	When available, quoted market prices or prices obtained through external sources are used to determine a financial instrument s fair value. The valuation of Level 2 financial instruments is based on quoted market prices for similar assets and liabilities in active markets and other inputs that are observable. However, for other financial instruments for which quoted market prices are not available, the fair value is based upon inputs that are largely unobservable. These instruments are classified as Level 3 under the fair value hierarchy. The fair value of these instruments are determined based on pricing models developed primarily from historical and expected correlations with quoted market prices. At June 30, 2013, approximately 72% of our net derivative assets are classified as Level 3 with the remainder classified as Level 2.	If the assumptions used in the pricing models for our financial instruments are inaccurate or if we had used an alternative valuation methodology, the estimated fair value may have been different, and we may be exposed to unrealized losses or gains that could be material. Of the $39.8 million and $31.0 million net derivative assets at June 30, 2013 and December 31, 2012, respectively, we had $28.6 million and $23.1 million net derivative assets at June 30, 2013 and December 31, 2012, respectively, that were classified as Level 3 fair value measurements, which rely on subjective forward developed price curves. Holding all other variables constant, a 10% change in the prices utilized in calculating the Level 3 fair value of derivatives at June 30, 2013 would have resulted in approximately an $11.3 million noncash change to net income for the six months ended June 30, 2013.

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Description	Judgments and Uncertainties	Effect if Actual Results Differ from Estimates and Assumptions
Acquisitions Purchase Price Allocation We allocate the purchase price of an acquired business to its identifiable assets and liabilities, including identifiable intangible assets, based upon estimated fair values. The excess of the purchase price over the amount allocated to the assets and liabilities is recorded as goodwill. For significant acquisitions, we engage outside appraisal firms to assist in the fair value determination of identifiable intangible assets such as customer relationships and contracts. We adjust the preliminary purchase price allocation, as necessary, after the acquisition closing date through the end of the measurement period of up to one year as we finalize valuations for the assets acquired and liabilities assumed.	Purchase price allocation methodology requires management to make assumptions and apply judgment to estimate the fair value of acquired assets and liabilities. Management estimates the fair value of assets and liabilities primarily using a market approach, income approach, or cost approach, as appropriate. Key inputs into the fair value determinations include estimates and assumptions related to future volumes, commodity prices, operating costs, replacement costs and construction costs, as well as an estimate of the expected term and profits of the related customer contracts.	If estimates or assumptions used to complete the purchase price allocation and estimate the fair value of acquired assets and liabilities significantly differs from assumptions made during the preliminary purchase price allocation, the allocation of purchase price between goodwill, intangibles and property plant and equipment could significantly differ. Such a difference would impact future earnings through depreciation and amortization expense. In addition, if forecasts supporting the valuation of the intangibles or goodwill are not achieved, impairments could arise.

Recently Adopted Accounting Standards

See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Recently Adopted Accounting Standards for information regarding recently adopted accounting pronouncements.

Recently Issued Accounting Standards

See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Recently Issued Accounting Standards for information regarding recently adopted accounting pronouncements.

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 our market risk sensitive instruments were entered into for purposes other than trading.

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative 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, 2013. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties to our commodity-based derivatives are banking institutions, or their affiliates, currently participating in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we are not aware of any inability on the part of our counterparties to perform under our contracts.

Interest Rate Risk. At June 30, 2013, we had a $600.0 million senior secured revolving credit facility with $80.0 million in outstanding borrowings. Borrowings under the revolving credit facility bear interest, at our option, at either (1) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (2) the LIBOR rate for the applicable period (each plus the applicable margin). The weighted average interest rate for the revolving credit facility borrowings was 3.2% at June 30, 2013. Based upon the outstanding borrowings on the senior secured revolving credit facility and holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by approximately $0.8 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. We use a number of different derivative instruments in connection with our commodity price 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. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under swap agreements, we receive a fixed price and remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right to receive the difference between a fixed price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 10 for further discussion of our derivative instruments. Average estimated market prices for NGLs, natural gas and condensate, based upon twelve-month forward price curves as of July 8, 2013, were $0.90 per gallon, $3.89 per million BTU and $98.77 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended June 30, 2014 by approximately $13.0 million.

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 Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management

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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, excluding the assets acquired through the TEAK Acquisition, which was completed on May 7, 2013 (see Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Acquisitions). Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2013, our disclosure controls and procedures were effective at the reasonable assurance level. There have been no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1A. RISK FACTORS

There have been no material changes in our risk factors from those disclosed in Part I, Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2012.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Securities Purchase Agreement dated November 30, 2012, by and among Cardinal Midstream, LLC, Cardinal Arkoma, Inc., Cardinal Arkoma Midstream, LLC, Cardinal Gas Treating LLC and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Securities Purchase Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.(30)
2.2	Purchase and Sale agreement, dated as of April 16, 2013, among TEAK Midstream Holdings, LLC, TEAK Midstream, L.L.C. and Atlas Pipeline Mid-Continent Holdings, LLC. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request(33)
3.1(a)	Certificate of Limited Partnership(1)
3.1(b)	Amendment to Certificate of Limited Partnership(12)
3.2(a)	Second Amended and Restated Agreement of Limited Partnership(2)
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership(3)
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership(4)
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership(5)
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership(6)
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership(8)
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership(9)
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership(14)
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership(15)
3.2(j)	Amendment No. 9 to Second Amended and Restated Agreement of Limited Partnership(12)
3.2(k)	Amendment No. 10 to Second Amended and Restated Agreement of Limited Partnership(36)
4.1	Common unit certificate (attached as Exhibit A to the Second Amended and Restated Agreement of Limited Partnership)(2)
4.2	8 3/4% Senior Notes Indenture dated June 27, 2008(7)
4.2(a)	Registration Rights Agreement, dated May 16, 2012, between Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein(25)
4.3(a)	6 5/8% Senior Notes Indenture dated September 28, 2012(26)
4.3(b)	Supplemental Indenture dated as of December 20, 2012(32)
4.4	5 7/8% Senior Notes Indenture dated as of February 11, 2013(10)

4.5	4 3/4% Senior Notes Indenture dated May 10, 2013[37]
4.6	Certificate of Designation of Class D Convertible Preferred Units[36]
10.1(a)	Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[1]
10.1(b)	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[14]
10.1(c)	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[12]
10.2	Amended and Restated Limited Liability Company Agreement of Atlas Pipeline Partners GP, LLC[19]
10.3(a)	Amended and Restated Credit Agreement dated July 27, 2007, amended and restated as of December 22, 2010, by and among Atlas Pipeline Partners, L.P., Wells Fargo Bank, National Association and the several guarantors and lenders hereto[16]
10.3(b)	Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011[22]

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Exhibit No.	Description
10.3(c)	Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011[23]
10.3(d)	Amendment No. 2 to the Amended and Restated Credit Agreement dated as of May 31, 2012[27]
10.3(e)	Amendment No. 3 to the Amended and Restated Credit Agreement[31]
10.3(f)	Amendment No. 4 to the Amended and Restated Credit Agreement[34]
10.4	Long-Term Incentive Plan[35]
10.5	Amended and Restated 2010 Long-Term Incentive Plan[22]
10.6	Form of Grant of Phantom Units in Exchange for Bonus Units[17]
10.7	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter[18]
10.8	Form of 2004 Long-Term Incentive Plan Phantom Unit Grant Letter[28]
10.9	Form of Grant of Phantom Units to Non-Employee Managers[11]
10.10	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010[13]
10.11	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010[20]
10.12	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010[20]
10.13	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[24]
10.14	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[24]
10.15	Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011[21]
10.16	Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012[25]
10.17	Equity Distribution Agreement dated November 5, 2012, by and between Atlas Pipeline Partners, L.P. and Citigroup Global Markets Inc.[29]
10.18	Registration Rights Agreement, dated September 28, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein[26]
10.19	Registration Rights Agreement, dated December 20, 2012, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein[32]
10.20	Class D preferred Unit Purchase Agreement, dated as of April 17, 2013, among Atlas Pipeline Partners, L.P. and the various purchasers party thereto[33]
10.21	Registration Rights Agreement, dated February 11, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries named therein, and the initial purchasers listed therein[10]
10.22	Purchase Agreement dated January 28, 2013 by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the subsidiaries listed therein, and Merrill Lynch, Pierce, Fenner & Smith Incorporated as representative of the several initial purchasers[26]
10.23	Registration Rights Agreement, dated May 7, 2013 by and among Atlas Pipeline Parnters, L.P. and the purchasers named therein[36]
10.24	Registration Rights Agreement, dated May 10, 2013, by and among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, the guarantors named therein, and Citigroup Global Markets Inc. for itself and on behalf of the initial purchasers[37]
10.25	Purchase Agreement dated May 7, 2013 among Atlas Pipeline Partners, L.P., Atlas Pipeline Finance Corporation, and Citigroup Global Markets Inc. as representatives of the several initial purchasers[37]
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
101.INS	XBRL Instance Document[38]
101.SCH	XBRL Schema Document[38]
101.CAL	XBRL Calculation Linkbase Document[38]
101.LAB	XBRL Label Linkbase Document[38]
101.PRE	XBRL Presentation Linkbase Document[38]
101.DEF	XBRL Definition Linkbase Document[38]

(1) Filed previously as an exhibit to registration statement on Form S-1 (Registration No. 333-85193).
(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 June 27, 2008.
(8) Previously filed as an exhibit to current report on Form 8-K on January 6, 2009.
(9) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(10) Previously filed as an exhibit to current report on Form 8-K filed on February 12, 2013.
(11) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
(12) Previously filed as an exhibit to current report on Form 8-K on December 13, 2011.
(13) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
(14) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
(15) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
(16) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.
(17) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
(18) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
(19) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2011.
(20) Previously filed as an exhibit to Atlas Energy, Inc. s current report on Form 8-K filed on November 12, 2010.
(21) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2011.
(22) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2011.
(23) Previously filed as an exhibit to current report on Form 8-K filed on July 11, 2011.
(24) Previously filed as an exhibit to Atlas Energy, L.P. s quarterly report on Form 10-Q for the quarter ended March 31, 2011.
(25) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2012.
(26) Previously filed as an exhibit to current report on Form 8-K filed on January 30, 2013.
(27) Previously filed as an exhibit to current report on Form 8-K filed on May 31, 2012.
(28) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2012.
(29) Previously filed as an exhibit to current report on Form 8-K filed on November 6, 2012.
(30) Previously filed as an exhibit to current report on Form 8-K filed on December 4, 2012.
(31) Previously filed as an exhibit to current report on Form 8-K filed on December 13, 2012.
(32) Previously filed as an exhibit to current report on Form 8-K filed on December 26, 2012.
(33) Previously filed as an exhibit to current report on Form 8-K filed on April 17, 2013.
(34) Previously filed as an exhibit to current report on Form 8-K filed on April 23, 2013.
(35) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.
(36) Previously filed as an exhibit to current report on Form 8-K filed on May 8, 2013.
(37) Previously filed as an exhibit to current report on Form 8-K filed on May 13, 2013.
(38) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed.

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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 9, 2013

By: /s/ EUGENE N. DUBAY
Eugene N. Dubay
Chief Executive Officer, President and Managing Board Member of the General Partner

Date: August 9, 2013

By: /s/ ROBERT W. KARLOVICH, III
Robert W. Karlovich, III
Chief Financial Officer and Chief Accounting Officer of the General Partner