ATLAS PIPELINE PARTNERS LP
Form 10-Q
August 07, 2012
Table of Contents

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, 2012

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 incorporation or organization)	**(I.R.S. Employer Identification No.)**
Park Place Corporate Center One	
1000 Commerce Drive, 4th Floor	
Pittsburg, 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 3, 2012 was 53,723,412.

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

INDEX TO QUARTERLY REPORT

ON FORM 10-Q

Table of Contents

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
IFRS	International Financial Reporting Standards
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.
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

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	June 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 257	$ 168
Accounts receivable	94,551	115,412
Current portion of derivative assets	37,343	1,645
Prepaid expenses and other	11,582	15,641
Total current assets	143,733	132,866
Property, plant and equipment, net	1,705,034	1,567,828
Intangible assets, net	111,702	103,276
Investment in joint ventures	86,092	86,879
Long-term portion of derivative assets	29,679	14,814
Other assets, net	24,162	25,149
Total assets	$ 2,100,402	$ 1,930,812
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 3,908	$ 2,085
Accounts payable affiliates	2,147	2,675
Accounts payable	38,067	54,644
Accrued liabilities	24,042	23,282
Accrued interest payable	1,999	1,624
Accrued producer liabilities	56,494	88,096
Total current liabilities	126,657	172,406
Long-term debt, less current portion	709,065	522,055
Other long-term liability	6,129	123
Commitments and contingencies		
Equity:		
Common limited partners interests	1,262,276	1,245,163
General Partner s interest	24,096	23,856
Accumulated other comprehensive loss	(2,136)	(4,390)
Total partners capital	1,284,236	1,264,629
Non-controlling interest	(25,685)	(28,401)

Total equity	1,258,551	1,236,228
Total liabilities and equity	$ 2,100,402	$ 1,930,812

See accompanying notes to consolidated financial statements

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Revenue:				
Natural gas and liquids sales	$ 238,801	$ 330,168	$ 528,026	$ 596,477
Transportation, processing and other fees third parties	14,756	10,380	27,358	19,668
Transportation, processing and other fees affiliates	122	55	201	177
Derivative gain (loss), net	67,847	6,837	55,812	(14,808)
Other income, net	2,588	2,745	5,003	5,534
Total revenues	324,114	350,185	616,400	607,048
Costs and expenses:				
Natural gas and liquids cost of sales	195,103	274,176	428,208	492,468
Plant operating	14,600	13,381	28,481	26,155
Transportation and compression	212	151	476	335
General and administrative	9,570	8,193	18,640	16,791
Compensation reimbursement affiliates	875	462	1,750	881
Other costs	(161)	575	(195)	575
Depreciation and amortization	21,712	19,123	42,554	38,028
Interest	9,269	6,145	17,977	18,590
Total costs and expenses	251,180	322,206	537,891	593,823
Equity income in joint ventures	1,917	687	2,813	1,149
Gain (loss) on asset sales and other		(273)		255,674
Loss on early extinguishment of debt		(19,574)		(19,574)
Income from continuing operations	74,851	8,819	81,322	250,474
Loss on sale of discontinued operations				(81)
Net income	74,851	8,819	81,322	250,393
Income attributable to non-controlling interests	(1,061)	(1,545)	(2,597)	(2,732)
Preferred unit dividends		(149)		(389)
Net income attributable to common limited partners and the General Partner	$ 73,790	$ 7,125	$ 78,725	$ 247,272

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Allocation of net income (loss) attributable to:				
Common limited partner interest:				
Continuing operations	$ 70,770	$ 6,982	$ 74,237	$ 242,381
Discontinued operations				(79)
	70,770	6,982	74,237	242,302
General Partner interest:				
Continuing operations	3,020	143	4,488	4,972
Discontinued operations				(2)
	3,020	143	4,488	4,970
Net income (loss) attributable to:				
Continuing operations	73,790	7,125	78,725	247,353
Discontinued operations				(81)
	$ 73,790	$ 7,125	$ 78,725	$ 247,272
Net income attributable to common limited partners per unit:				
Basic	$ 1.30	$ 0.13	$ 1.37	$ 4.50
Weighted average common limited partner units (basic)	53,646	53,517	53,633	53,446
Diluted	$ 1.30	$ 0.13	$ 1.37	$ 4.50
Weighted average common limited partner units (diluted)	54,510	53,909	54,262	53,878

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands)

(Unaudited)

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net income	$ 74,851	$ 8,819	$ 81,322	$ 250,393
Income attributable to non-controlling interests	(1,061)	(1,545)	(2,597)	(2,732)
Preferred unit dividends		(149)		(389)
Net income attributable to common limited partners and the General Partner	73,790	7,125	78,725	247,272
Other comprehensive income:				
Adjustment for realized losses on cash flow hedges reclassified to net income	1,108	1,702	2,254	3,404
Comprehensive income	$ 74,898	$ 8,827	$ 80,979	$ 250,676

See accompanying notes to consolidated financial statements

7

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

FOR THE SIX MONTHS ENDED JUNE 30, 2012

(in thousands, except unit data)

(Unaudited)

	Number of Limited Partner Common Units	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
Balance at December 31, 2011	53,617,183	$ 1,245,163	$ 23,856	$ (4,390)	$ (28,401)	$ 1,236,228
Issuance of common units under incentive plans	115,429	77				77
Equity based compensation expense		3,836				3,836
Purchase and retirement of treasury stock	(24,052)	(695)				(695)
Distributions paid		(60,342)	(4,248)			(64,590)
Distributions received from non-controlling interests					119	119
Other comprehensive income				2,254		2,254
Net income		74,237	4,488		2,597	81,322
Balance at June 30, 2012	53,708,560	$ 1,262,276	$ 24,096	$ (2,136)	$ (25,685)	$ 1,258,551

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 81,322	$ 250,393
Add: loss from discontinued operations		(81)
Net income from continuing operations	81,322	250,474
Adjustments to reconcile net income from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	42,554	38,028
Equity income in joint ventures	(2,813)	(1,149)
Distributions received from joint ventures	3,600	1,764
Non-cash compensation expense	3,918	1,679
Amortization of deferred finance costs	2,295	2,301
Gain on asset sales		(255,674)
Loss on early extinguishment of debt		19,574
Change in operating assets and liabilities, net of business combinations:		
Accounts receivable, prepaid expenses and other	24,920	(16,301)
Accounts payable and accrued liabilities	(42,428)	24,982
Accounts payable and accounts receivable affiliates	(528)	(9,962)
Derivative accounts payable and receivable	(48,309)	(3,806)
Net cash provided by operating activities	64,531	51,910
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(146,388)	(91,969)
Capital contribution to joint ventures		(12,250)
Cash paid for business combinations	(36,689)	(85,000)
Net proceeds related to asset sales		411,480
Other	250	382
Net cash provided by (used in) continuing investing activities	(182,827)	222,643
Net cash used in discontinued investing activities		(81)
Net cash provided by (used in) investing activities	(182,827)	222,562
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facility	480,500	387,000
Repayments under credit facility	(292,000)	(314,500)
Repayment of debt		(279,557)
Payment of premium on early retirement of debt		(14,342)
Payments of deferred financing costs	(3,358)	
Principal payments on capital lease	(1,191)	(104)
Net proceeds from issuance of common limited partner units		468
Purchase and retirement of treasury units	(695)	(812)

Redemption of preferred limited partner units		(8,000)
Net distributions received from (paid to) non-controlling interest holders	119	(1,592)
Distributions paid to common limited partners, the General Partner and preferred limited partners	(64,590)	(42,947)
Other	(400)	(84)
Net cash provided by (used in) financing activities	118,385	(274,470)
Net change in cash and cash equivalents	89	2
Cash and cash equivalents, beginning of period	168	164
Cash and cash equivalents, end of period	$ 257	$ 166

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

JUNE 30, 2012

(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 and processing 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, 2012, 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, 2012, the Partnership had 53,708,560 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by ATLS.

The accompanying consolidated financial statements, which are unaudited except the balance sheet at December 31, 2011 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, 2011. The results of operations for the six month period ended June 30, 2012 may not necessarily be indicative of the results of operations for the full year ending December 31, 2012. The Partnership has evaluated all events subsequent to the balance sheet date through the filing date of this Form 10-Q and has determined there are no subsequent events that require disclosure.

The Partnership has retrospectively adjusted its prior period consolidated financial statements to separately present derivative gain (loss) within derivative gain (loss), net instead of combining these amounts in other income, net.

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, 2011.

Equity Method Investments

The Partnership s consolidated financial statements include its previously owned 49% non-controlling interest in Laurel Mountain Midstream, LLC joint venture (Laurel Mountain), until it was sold February 17, 2011; and its 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG), after its acquisition on May 11, 2011. The Partnership accounts for its investment in the joint ventures under the equity method of accounting. Under this method, the Partnership records its proportionate share of the joint ventures net income (loss) as equity income (loss) on its consolidated statements of operations (see Note 3). 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 (loss) 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 Laurel Mountain or WTLPG. Equity method investments are subject to impairment evaluation.

NGL Linefill

The Partnership had $6.3 million and $11.5 million of NGL linefill at June 30, 2012 and December 31, 2011, 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.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs which generally do not extend the useful life of an asset for two or more years through the replacement of critical components are expensed as incurred. Major renewals and improvements that generally extend the useful lives of an asset for two or more years through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset s estimated useful life. The Partnership follows the composite method of depreciation and has determined the composite groups to be the major asset classes of its gathering and processing systems. Under the composite depreciation method, any gain or loss upon disposition or retirement of pipeline, gas gathering and processing components, is recorded to accumulated depreciation. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership s results of operations.

Intangible Assets

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer contract intangible assets is based upon the approximate average length of customer contracts in existence and expected renewals at the date of acquisition. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management s estimate of whether these individual relationships will continue in excess or less than the average length (see Note 7).

Table of Contents

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% 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.

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 14), 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.

The following is a reconciliation of net income (loss) from continuing operations and net income from discontinued operations 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,	
	2012	2011	2012	2011
Continuing operations:				
Net income	$ 74,851	$ 8,819	$ 81,322	$ 250,474
Income attributable to non-controlling interests	(1,061)	(1,545)	(2,597)	(2,732)
Preferred unit dividends		(149)		(389)
Net income attributable to common limited partners and the General Partner	73,790	7,125	78,725	247,353
General Partner s cash incentive distributions paid	1,569		2,966	
General Partner s ownership interest	1,451	143	1,522	4,972
Net income attributable to the General Partner s ownership interests	3,020	143	4,488	4,972
Net income attributable to common limited partners	70,770	6,982	74,237	242,381
Net income attributable to participating securities phantom units[(1)]	1,122	51	860	1,940
Net income utilized in the calculation of net income from continuing operations attributable to common limited partners per unit	$ 69,648	$ 6,931	$ 73,377	$ 240,441
Discontinued operations:				
Net loss	$	$	$	$ (81)
Net loss attributable to the General Partner s ownership interests				(2)
Net loss utilized in the calculation of net loss from discontinued operations attributable to common limited partners per unit	$	$	$	$ (79)

(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).

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 and unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership s long-term incentive plans (see Note 14).

Table of Contents

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,	
	2012	2011	2012	2011
Weighted average number of common limited partner units basic	53,646	53,517	53,633	53,446
Add effect of dilutive securities phantom units	864	392	629	432
Weighted average common limited partner units diluted	54,510	53,909	54,262	53,878

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 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, at 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 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, 2012 and December 31, 2011 of $58.0 million and $68.6 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

Recently Adopted Accounting Standards

In May 2011, the FASB issued Accounting Standards Update (ASU) 2011-04, Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRS, which, among other changes, requires (1) additional disclosures for fair value measurements categorized within Level 2 and Level 3 of the fair value hierarchy; and (2) additional disclosures for items not measured at fair value in the Partnership s consolidated balance sheets but for which the fair value is required to be disclosed. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. The Partnership updated its disclosures to meet these requirements upon the adoption of this ASU on January 1, 2012 (see Note 10). The adoption had no material impact on the Partnership s financial position or results of operations.

In June 2011, the FASB issued ASU 2011-05, Comprehensive Income (Topic 220) Presentation of Comprehensive Income, which, among other changes, eliminates the option to present components of other comprehensive income as part of the statement of changes in equity. In December 2011, the FASB issued ASU 2011-12, Comprehensive Income (Topic 220) Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05, which supersedes the requirements in ASU 2011-05 pertaining to how, when and where reclassifications out of accumulated other comprehensive income are presented on the face of the financial statements and reinstates the requirements for the presentation of reclassifications out of accumulated other comprehensive income that were in place before the issuance of ASU 2011-05. The amendments in these updates require all non-owner changes in equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements. The updates do 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, 2011. The Partnership began including consolidated statements of comprehensive income within its Form 10-Qs upon the adoption of these ASUs on January 1, 2012. The adoption had no material impact on the Partnership s financial position or results of operations.

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210) Disclosures about Offsetting Assets and Liabilities, which requires an entity to disclose additional information regarding offsetting arrangements for derivative instruments that are presented as net balances within its financial statements. Entities are required to implement the amendments for interim and annual reporting periods beginning after January 1, 2013 and apply them retrospectively for any period presented that begins before the date of initial application. The Partnership has elected to adopt these requirements early and has updated its disclosures to meet these requirements effective January 1, 2012 (see Note 9). The adoption had no material impact on the Partnership s financial position or results of operations.

Table of Contents

NOTE 3 INVESTMENT IN JOINT VENTURES

Laurel Mountain

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain to Atlas Energy Resources, LLC (Atlas Energy Resources), a wholly-owned subsidiary of Atlas Energy, Inc. (the Laurel Mountain Sale) for $409.5 million in cash, including closing adjustments and net of expenses. Concurrently, Atlas Energy, Inc. became a wholly-owned subsidiary of Chevron Corporation (the Chevron Merger) and divested its interests in ATLS, resulting in the Laurel Mountain Sale being classified as a third party sale. The Partnership recognized on its consolidated statements of operations a $0.3 million loss during the three months ended June 30, 2011 for expenses related to the sale and recognized a $255.7 million gain during the six months ended June 30, 2011. Laurel Mountain is a joint venture, which owns and operates the Appalachia natural gas gathering system previously owned by the Partnership. Subsidiaries of The Williams Companies, Inc. (NYSE: WMB) (Williams) hold the remaining 51% ownership interest. The Partnership utilized the proceeds from the sale to repay its indebtedness (see Note 12) and for general company purposes.

The Partnership recognized its 49% non-controlling ownership interest in Laurel Mountain as an investment in joint ventures on its consolidated balance sheets at fair value. The Partnership accounted for its ownership interest in Laurel Mountain under the equity method of accounting, with recognition of its ownership interest in the income of Laurel Mountain as equity income in joint ventures on its consolidated statements of operations. Since the Partnership accounted for its ownership as an equity investment, the Partnership did not reclassify the earnings or the gain on sale related to Laurel Mountain to discontinued operations upon the sale of its ownership interest.

West Texas LPG Pipeline Limited Partnership

On May 11, 2011, the Partnership acquired a 20% interest in WTLPG from Buckeye Partners, L.P. (NYSE: BPL) for $85.0 million. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest. At the acquisition date, the carrying value of the 20% interest in WTLPG exceeded the Partnership s share of the underlying net assets of WTLPG by approximately $49.9 million. The Partnership s analysis of this difference determined that it related to the fair value of property plant and equipment, which was in excess of book value. This excess will be depreciated over approximately 38 years. The Partnership recognizes its 20% interest in WTLPG as an investment in joint ventures on its consolidated balance sheets. The Partnership accounts for its ownership interest in WTLPG under the equity method of accounting, with recognition of its ownership interest in the income of WTLPG as equity income in joint ventures on its consolidated statements of operations. The Partnership incurred costs of $0.6 million during the three and six months ended June 30, 2011, related to the acquisition of WTLPG, which are reported as other costs within the Partnership s consolidated statements of operations.

The following table summarizes the components of equity income on the Partnership s statements of operations (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Equity income in Laurel Mountain	$	$	$	$ 462
Equity income in WTLPG	1,917	687	2,813	687
Equity income in joint ventures	$ 1,917	$ 687	$ 2,813	$ 1,149

Table of Contents

NOTE 4 PREFERRED UNIT EQUITY OFFERINGS

On February 17, 2011, as part of the Chevron Merger (see Note 3), Chevron acquired 8,000 12% Cumulative Class C Preferred Units of limited partner interest (the Class C Preferred Units), which were previously owned by Atlas Energy, Inc. On May 27, 2011, the Partnership redeemed the Class C Preferred Units for cash at the liquidation value of $1,000 per unit, or $8.0 million, plus $0.2 million of accrued dividends. The Partnership recognized $0.2 million and $0.4 million of preferred dividends for the three and six months ended June 30, 2011, respectively, which are presented as reductions of net income to determine the net income attributable to common limited partners and the General Partner on its consolidated statements of operations.

NOTE 5 CASH 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 and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. 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. Common unit and General Partner distributions declared by the Partnership for quarters ending from March 31, 2011 through March 31, 2012 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, 2011	May 13, 2011	0.40	21,400	439
June 30, 2011	August 12, 2011	0.47	25,184	967
September 30, 2011	November 14, 2011	0.54	28,953	1,844
December 31, 2011	February 14, 2012	0.55	29,489	2,031
March 31, 2012	May 15, 2012	0.56	30,030	2,217

On July 17, 2012, the Partnership declared a cash distribution of $0.56 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2012. The $32.3 million distribution, including $2.2 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on August 14, 2012 to unitholders of record at the close of business on August 7, 2012.

Table of Contents

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 12) (in thousands):

	June 30, 2012	December 31, 2011	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,768,812	$ 1,615,015	2 40
Rights of way	173,824	161,191	20 40
Buildings	8,206	8,047	40
Furniture and equipment	9,714	9,392	3 7
Other	14,721	14,029	3 10
	1,975,277	1,807,674	
Less accumulated depreciation	(270,243)	(239,846)	
	$ 1,705,034	$ 1,567,828	

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 6.3% and 7.3% for the three months ended June 30, 2012 and 2011, respectively, and 6.5% and 7.7% for the six months ended June 30, 2012 and 2011, respectively. The amount of interest capitalized was $2.0 million and $1.1 million for the three months ended June 30, 2012 and 2011, respectively, and $4.2 million and $1.3 million for the six months ended June 30, 2012 and 2011, respectively.

The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 12), of $15.7 million and $13.3 million for the three months ended June 30, 2012 and 2011, respectively, and $30.8 million and $26.4 million for the six months ended June 30, 2012 and 2011, respectively, on its consolidated statements of operations.

NOTE 7 INTANGIBLE ASSETS

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The Partnership completed acquisitions of various gas gathering systems and related assets during the six months ended June 30, 2012. The Partnership accounted for these acquisitions as business combinations and recognized $20.2 million related to customer contracts with an estimated useful life of 10-14 years. The initial recording of these transactions was based upon preliminary valuation assessments and is subject to change. The following table reflects the components of intangible assets being amortized at June 30, 2012 and December 31, 2011 (in thousands):

	June 30, 2012	December 31, 2011	Estimated Useful Lives In Years
Gross carrying amount:			
Customer contracts	$ 20,230	$	10-14
Customer relationships	205,313	205,313	7 10
	225,543	205,313	
Accumulated amortization:			
Customer contracts	(253)		
Customer relationships	(113,588)	(102,037)	
	(113,841)	(102,037)	

Net carrying amount:		
Customer contracts	19,977	
Customer relationships	91,725	103,276
Net carrying amount	$ 111,702	$ 103,276

The weighted-average amortization period for customer contracts and customer relationships is 12.1 years and 9.1 years, respectively. The Partnership recorded amortization expense on intangible assets of $6.0 million and $5.8 million for the three months ended June 30, 2012 and 2011, respectively, and $11.8 million and $11.6 million for the six months ended June 30, 2012 and 2011, 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 2012 - $12.4 million; 2013 - $24.8 million; 2014 - $21.3 million; 2015 to 2016 - $16.3 million per year.

NOTE 8 OTHER ASSETS

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

	June 30, 2012	December 31, 2011
Deferred finance costs, net of accumulated amortization of $21,159 and $18,864 at June 30, 2012 and December 31, 2011, respectively	$ 21,814	$ 20,750
Security deposits	2,348	4,399
	$ 24,162	$ 25,149

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 12). During the three and six months ended June 30, 2012, the Partnership incurred $3.3 million deferred finance costs related to the May 31, 2012 amendment of the Partnership s revolving credit facility (see Note 12). During the three and six months ended June 30, 2011, the Partnership recorded $5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of its 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) and partial redemption of its 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes). This expense is included in loss on early extinguishment of debt on the Partnership s consolidated statements of operations (see Note 12). Amortization expense of deferred finance costs was $1.1 million and $1.0 million for the three months ended June 30, 2012 and 2011, respectively, and $2.3 million for each of the six months ended June 30, 2012 and 2011, which is recorded within interest expense on the Partnership s consolidated statements of operations.

NOTE 9 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 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, will be reclassified to the Partnership s consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings. The Partnership will reclassify the $2.1 million net loss in accumulated other comprehensive loss, within equity on the Partnership s consolidated balance sheets at June 30, 2012, to natural gas and liquids sales on the Partnership s consolidated statements of operations within the next twelve month period.

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 $67.0 million and $16.5 million at June 30, 2012 and December 31, 2011, respectively.

The following table 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):

	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amounts of Assets Presented in the Consolidated Balance Sheets
Offsetting of Derivative Assets			
As of June 30, 2012			
Current portion of derivative assets	$ 38,366	$ (1,023)	$ 37,343
Long-term portion of derivative assets	30,098	(419)	29,679
Total derivative assets, net	$ 68,464	$ (1,442)	$ 67,022
As of December 31, 2011			
Current portion of derivative assets	$ 11,603	$ (9,958)	$ 1,645
Long-term portion of derivative assets	17,011	(2,197)	14,814
Total derivative assets, net	$ 28,614	$ (12,155)	$ 16,459

Table of Contents

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, 2012			
Current portion of derivative liabilities	$ (1,023)	$ 1,023	$
Long-term portion of derivative liabilities	(419)	419	
Total derivative liabilities, net	$ (1,442)	$ 1,442	$
As of December 31, 2011			
Current portion of derivative liabilities	$ (9,958)	$ 9,958	$
Long-term portion of derivative liabilities	(2,197)	2,197	
Total derivative liabilities, net	$ (12,155)	$ 12,155	$

The following table summarizes the Partnership s commodity derivatives as of June 30, 2012, (dollars and volumes in thousands):

ProductionPeriod	Commodity	Volumes(1)	Average Fixed Price ($/Volume)	Fair Value(2) Asset/ (Liability)
Fixed price swaps				
2012	Natural gas	2,460	$ 3.12	$ 415
2013	Natural gas	1,200	3.48	(59)
2014	Natural gas	5,400	3.90	(228)
2012	NGLs	16,380	1.53	7,450
2013	NGLs	49,896	1.29	18,829
2014	NGLs	630	1.27	210
2012	Crude oil	144	96.09	1,447
2013	Crude oil	345	97.17	3,032
2014	Crude oil	60	98.43	626
Total fixed price swaps				31,722
Options				
Purchased put options				
2012	NGLs	29,736	1.57	11,620
2013	NGLs	38,556	1.94	14,857
2012	Crude oil	78	106.18	1,618
2013	Crude oil	282	100.10	4,799
2014	Crude oil	137	104.75	3,055
Purchased call options(3)				
2012	Crude oil	90	125.20	14
Sold call options(3)				
2012	Crude oil	249	94.69	(663)

Total options		35,300
Total derivatives	$	67,022

(1) NGL volumes are stated in gallons. Crude oil volumes are stated in barrels. Natural gas volumes are stated in MMBTUs.
(2) See Note 10 for discussion on fair value methodology.
(3) Calls purchased for 2012 represent offsetting positions for calls sold as part of costless collars. These offsetting positions were entered into to limit potential loss, which could be incurred if crude oil prices continued to rise.

Table of Contents

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,		For the Six Months ended June 30,	
	2012	2011	2012	2011
Derivatives previously designated as cash flow hedges				
Loss reclassified from accumulated other comprehensive loss into natural gas and liquids sales	$ (1,108)	$ (1,702)	$ (2,254)	$ (3,404)
Derivatives not designated as hedges				
Commodity contract - realized(1)	$ 3,685	$ (6,236)	$ 2,922	$ (8,793)
Commodity contract - unrealized(2)	64,162	13,073	52,890	(6,015)
Derivative gain (loss), net	$ 67,847	$ 6,837	$ 55,812	$ (14,808)

(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 10 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.

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 9). 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, 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 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.

Table of Contents

Derivative Instruments and NGL Linefill

At June 30, 2012, 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.

The following table represents the Partnership s derivative assets and liabilities recorded at fair value as of June 30, 2012 and December 31, 2011 (in thousands):

	Level 1	Level 2	Level 3	Total
As of June 30, 2012				
Derivative assets, gross				
Commodity swaps	$	$ 6,012	$ 26,489	$ 32,501
Commodity options		9,486	26,477	35,963
Total derivative assets, gross		15,498	52,966	68,464
Derivative liabilities, gross				
Commodity swaps		(779)		(779)
Commodity options		(663)		(663)
Total derivative liabilities, gross		(1,442)		(1,442)
Total derivatives, fair value, net	$	$ 14,056	$ 52,966	$ 67,022

Table of Contents

	Level 1	Level 2	Level 3	Total
As of December 31, 2011				
Derivative assets, gross				
Commodity swaps	$	$ 1,270	$ 1,836	$ 3,106
Commodity options		7,229	18,279	25,508
Total derivative assets, gross		8,499	20,115	28,614
Derivative liabilities, gross				
Commodity swaps		(2,766)	(3,569)	(6,335)
Commodity options		(5,820)		(5,820)
Total derivative liabilities, gross		(8,586)	(3,569)	(12,155)
Total derivatives, fair value, net	$	$ (87)	$ 16,546	$ 16,459

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, 2012 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Gallons	Amount	Gallons	Amount	Amount
Balance December 31, 2011	49,644	$ (1,733)	92,610	$ 18,279	$ 16,546
New contracts(1)	47,754				
Cash settlements from unrealized gain (loss)(2)(3)	(30,492)	(2,852)	(24,318)	108	(2,744)
Net change in unrealized gain (loss)(2)		31,074		13,285	44,359
Deferred option premium recognition(3)				(5,195)	(5,195)
Balance June 30, 2012	66,906	$ 26,489	68,292	$ 26,477	$ 52,966

(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 gain (loss), 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.

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, 2012 and December 31, 2011 (in thousands):

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of June 30, 2012				
Propane swaps	57,078	$ 22,755	$ (345)	$ 22,410
Isobutane swaps	2,646	174	399	573
Normal butane swaps	5,040	1,872	36	1,908
Natural gasoline swaps	2,142	1,893	(295)	1,598
Total NGL swaps June 30, 2012	66,906	$ 26,694	$ (205)	$ 26,489

Table of Contents

	Gallons	Third Party Quotes(1)	Adjustments(2)	Total Amount
As of December 31, 2011				
Ethane swaps	6,678	$ 31	$	$ 31
Propane swaps	29,358	(1,322)		(1,322)
Isobutane swaps	2,646	(1,590)	570	(1,020)
Normal butane swaps	6,804	(1,074)	343	(731)
Natural gasoline swaps	4,158	1,824	(515)	1,309
Total NGL swaps December 31, 2011	49,644	$ (2,131)	$ 398	$ (1,733)

(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 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, 2012				
Propane	$ (345)	0.9100	0.9204	0.9152
Isobutane	399	1.1195	1.1285	1.1240
Normal butane	36	0.9926	1.0194	1.0060
Natural gasoline	(295)	0.9028	0.9149	0.9089
Total Level 3 adjustments June 30, 2012	$ (205)			
As of December 31, 2011				
Isobutane	$ 570	1.1239	1.1333	1.1286
Normal butane	343	1.0311	1.0355	1.0333
Natural gasoline	(515)	0.9351	0.9426	0.9389
Total Level 3 adjustments December 31, 2011	$ 398			

The Partnership had $6.3 million and $11.5 million of NGL linefill at June 30, 2012 and December 31, 2011, 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 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 $0.5 million and $0.8 million as of June 30, 2012 and December 31, 2011, respectively.

25

The following table provides a summary of changes in fair value of the Partnership s NGL linefill for the six months ended June 30, 2012 (in thousands):

	NGL Linefill	
	Gallons	Amount
Balance December 31, 2011	10,408	$ 11,529
Cash settlements[(1)]	(2,520)	(2,698)
Net change in NGL linefill valuation[(1)]		(2,495)
Balance June 30, 2012	7,888	$ 6,336

(1) 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 agreed to pay up to an additional $12.0 million, payable in two equal amounts (Trigger Payments), if certain volumes are achieved on the acquired gathering system within a specified time period. The fair value of the Trigger Payments recognized upon acquisition resulted in a $6.0 million current liability, which was recorded within accrued liabilities on the Partnership s consolidated balance sheets, and a $6.0 million long term liability, which was recorded within other long term liabilities on the Partnership s consolidated balance sheets. The initial recording of the transaction was based upon preliminary valuation assessments and is subject to change. The range of the undiscounted amounts the Partnership could pay related to the Trigger Payments is between $0 and $12.0 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 8.75% Senior Notes is based upon the market approach and calculated using the yield of the 8.75% 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, 2012 and December 31, 2011, which consists principally of borrowings under the revolving credit facility and the 8.75% Senior Notes, were $734.3 million and $537.3 million, respectively, compared with the carrying amounts of $713.0 million and $524.1 million, respectively.

Table of Contents

NOTE 11 ACCRUED LIABILITIES

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

	June 30, 2012	December 31, 2011
Accrued capital expenditures	$ 8,143	$ 10,128
Accrued ad valorem taxes	6,804	3,615
Acquisition-based short-term contingent consideration	6,000	
Other	3,095	9,539
	$ 24,042	$ 23,282

NOTE 12 DEBT

Total debt consists of the following (in thousands):

	June 30, 2012	December 31, 2011
Revolving credit facility	$ 330,500	$ 142,000
8.75% Senior notes due 2018	370,584	370,983
Capital lease obligations	11,889	11,157
Total debt	712,973	524,140
Less current maturities	(3,908)	(2,085)
Total long-term debt	$ 709,065	$ 522,055

Cash payments for interest related to debt, net of capitalized interest, were $15.9 million and $16.5 million for the three months ended June 30, 2012 and 2011, respectively, and $15.3 million and $17.2 million for the six months ended June 30, 2012 and 2011, respectively.

Revolving Credit Facility

At June 30, 2012, 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, 2012, was 2.7%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.1 million was outstanding at June 30, 2012. These outstanding letters of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At June 30, 2012, the Partnership had $269.4 million of remaining committed capacity under its revolving credit facility.

On May 31, 2012, the Partnership entered into an amendment to its revolving credit facility agreement, which among other changes:

- increased the revolving credit facility from $450.0 million to $600.0 million;
- extended the maturity date from December 22, 2015 to May 31, 2017;

reduced the Applicable Margin used to determine interest rates by 0.50%;

revised the negative covenants to (i) permit investments in joint ventures equal to the greater of 20% of Consolidated Net Tangible Assets (as defined in the credit agreement) or $340 million, provided the Partnership meets certain requirements, and (ii) increased the general investment basket to 5% of Consolidated Net Tangible Assets ;

Table of Contents

revised the definition of Consolidated EBITDA to provide for the inclusion of the first twelve months of projected revenues for identified capital expansion projects, upon completion of the projects and contingent upon prior approval by the administrative agent. The addition from any such projects, in the aggregate, may not exceed 15% of unadjusted Consolidated EBITDA; and

provided for the potential increase of revolving credit commitments up to an additional $200.0 million.

Borrowings under the revolving credit facility are secured by a lien on and security interest in all the Partnership s property and that of its subsidiaries, except for the assets owned by WestOK and WestTX joint ventures; and 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. As of June 30, 2012, the Partnership was in compliance with all covenants under the credit facility.

Senior Notes

At June 30, 2012, the Partnership had $370.6 million principal amount outstanding of 8.75% Senior Notes, including a net $4.8 million unamortized premium. Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% 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 8.75% Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its revolving credit facility.

On April 7, 2011, the Partnership redeemed $7.2 million of the 8.75% Senior Notes, which were tendered upon its offer to purchase the 8.75% Senior Notes, at par. The sale of the Partnership s 49% non-controlling interest in Laurel Mountain on February 17, 2011 (see Note 3) constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, the Partnership offered to purchase the 8.75% Senior Notes.

The indenture governing the 8.75% Senior Notes contains 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, 2012.

Table of Contents

On April 8, 2011, the Partnership redeemed all the 8.125% Senior Notes. The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. The Partnership paid $293.7 million to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest.

Capital Leases

During the six months ended June 30, 2012, the Partnership recorded $1.9 million related to new capital lease agreements within property, plant and equipment and recorded an offsetting liability within long term debt on the Partnership s consolidated balance sheets. This amount was based upon the minimum payments required under the leases and the Partnership s incremental borrowing rate. The following is a summary of the leased property under capital leases as of June 30, 2012 and December 31, 2011, which are included within property, plant and equipment (see Note 6) (in thousands):

	June 30, 2012	December 31, 2011
Pipelines, processing and compression facilities	$ 14,512	$ 12,507
Less accumulated depreciation	(695)	(199)
	$ 13,817	$ 12,308

Depreciation expense for leased properties was $185 thousand and $14 thousand for the three months ended June 30, 2012 and 2011, respectively and $352 thousand and $28 thousand for the six months ended June 30, 2012 and 2011, respectively which is included within depreciation and amortization expense on the Partnership s consolidated statements of operations (see Note 6).

As of June 30, 2012, future minimum lease payments related to the capital leases are as follows (in thousands):

	Capital Lease Minimum Payments
2012	$ 1,665
2013	10,879
2014	64
2015	
2016	
Thereafter	
Total minimum lease payments	12,608
Less amounts representing interest	(719)
Present value of minimum lease payments	11,889
Less current portion of capital lease obligations	(3,908)
Long-term capital lease obligations	$ 7,981

NOTE 13 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 $2.5 million and $2.4 million for three months ended June 30, 2012 and 2011, respectively

and $5.0 million and $4.9 million for six months ended June 30, 2012 and 2011, respectively. The future fixed and determinable portion of the obligations as of June 30, 2012 was as follows: remainder of 2012 - $4.1 million; 2013 - $8.2 million; and 2014 - $6.1 million.

The Partnership had committed approximately $106.8 million for the purchase of property, plant and equipment at June 30, 2012.

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 14   BENEFIT PLANS

Generally, 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. Except for phantom units awarded to non-employee managing board members of the General Partner and within the guidelines proscribed in each long term incentive plan, a committee (the LTIP Committee) appointed by the General Partner s managing board 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 LTIP Committee shall determine how the exercise price may be paid by the grantee. The LTIP Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

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 LTIP Committee. Under the LTIPs, the LTIP Committee may make awards of either phantom units or unit options for an aggregate of 3,435,000 common units. At June 30, 2012, the Partnership had 972,402 phantom units outstanding under the LTIPs, with 1,670,145 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.

Partnership Phantom Units. Through June 30, 2012, 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 may automatically vest upon a change of control, as defined in the LTIPs. At June 30, 2012, there were 253,138 units outstanding under the LTIPs that will vest within the following twelve months. On February 17, 2011, the employment agreement with the Chief Executive Officer (CEO) of the General Partner was terminated in connection with the Chevron Merger (see Note 3) and 75,250 outstanding phantom units, which represent all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at June 30, 2012 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were $0.6 million and $0.1 million, during the three months ended June 30, 2012 and 2011, respectively and $0.8 million and $0.3 million, during the six months ended June 30, 2012 and 2011, 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,			
	2012		2011		2012		2011	
	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	390,567	$ 21.41	414,716	$ 11.65	394,489	$ 21.63	490,886	$ 11.75
Granted	693,952	34.97	125,123	33.03	698,084	34.98	130,853	32.93
Forfeited	(3,950)	24.66			(3,950)	24.66		
Matured and issued(2)	(108,167)	11.35	(103,414)	11.36	(116,221)	13.32	(185,314)	12.35
Outstanding, end of period(3)(4)	972,402	$ 32.19	436,425	$ 17.84	972,402	$ 32.19	436,425	$ 17.84
Matured and not issued(5)	48,647	$ 24.12	28,750	$ 11.41	48,647	$ 24.12	28,750	$ 11.41
Non-cash compensation expense recognized (in thousands)(6)		$ 2,940		$ 502		$ 3,918		$ 1,676

(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, 2012 and 2011 were $3.2 million and $3.5 million, respectively, and $3.5 million and $5.9 million during the six months ended June 30, 2012 and 2011, respectively.
(3) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2012 and 2011 was $30.3 million and $14.4 million, respectively.
(4) There were 17,852 and 14,311 outstanding phantom unit awards at June 30, 2012 and 2011, 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, 2012 and 2011 was $1.5 million and $0.9 million, respectively.
(6) Non-cash compensation expense for the six months ended June 30, 2011 includes incremental compensation expense of $0.5 million, related to the accelerated vesting of phantom units held by the CEO of the General Partner.

At June 30, 2012, the Partnership had approximately $25.6 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 2.3 years.

Partnership Unit Options. At June 30, 2012, there were no unit options outstanding. On February 17, 2011, the employment agreement with the CEO of the General Partner was terminated in connection with the Chevron Merger (see Note 3) and 50,000 outstanding unit options held by the CEO automatically vested. As of June 30, 2012, all unit options had been exercised.

Table of Contents

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2012		2011		2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period		$		$		$	75,000	$ 6.24
Exercised[(1)]							(75,000)	6.24
Outstanding, end of period		$		$		$		$
Non-cash compensation expense recognized (in thousands)[(2)]		$		$		$		$ 3

(1) The intrinsic value for option unit awards exercised during the six months ended June 30, 2011 was $1.8 million. Approximately $0.5 million was received from exercise of unit option awards during the six months ended June 30, 2011.

(2) Non-cash compensation expense for the six months ended June 30, 2011 includes incremental compensation expense of $2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner.

Employee Incentive Compensation Plan and Agreement

At June 30, 2012, Atlas Pipeline Mid-Continent LLC, a wholly-owned subsidiary of the Partnership, had an incentive plan (the APLMC Plan) which allows for equity-indexed cash incentive awards to employees of the Partnership (the Participants). The APLMC Plan is administered by a committee appointed by the CEO of the General Partner. Under the APLMC Plan, cash bonus units (Bonus Unit) may be awarded to Participants at the discretion of the committee. A Bonus Unit entitles the employee to receive the cash equivalent of the then fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. During the three and six month periods ended June 30, 2012 and the three and six month periods ended June 30, 2011, 25,500 Bonus Units and 24,750 Bonus Units, respectively, vested and cash payments were made for $0.7 million and $0.9 million, respectively. The Partnership recognizes compensation expense related to these awards based upon the fair value, which is re-measured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized income of $115 thousand during the three months ended June 30, 2012 and expense of $125 thousand during the three months ended June 30, 2011 and recognized income of $79 thousand during the six months ended June 31, 2012 and expense of $630 thousand during the six months ended June 31, 2011, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had $0.8 million at December 31, 2011 included within accrued liabilities on its consolidated balance sheets with regard to these awards, which represents their fair value as of that date. At June 30, 2012, the Partnership had no outstanding Bonus Units.

NOTE 15 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 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 $0.9 million and $0.5 million for the three months ended June 30, 2012 and 2011, respectively, and $1.8 million $0.9 million for the six months ended June 30, 2011 and 2010, 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, 2012 and 2011. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

On February 17, 2011, the Partnership completed the sale of its 49% interest in Laurel Mountain to Atlas Energy Resources for $409.5 million, including closing adjustments and net of expenses (See Note 3).

NOTE 16 SEGMENT INFORMATION

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

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins; (2) the natural gas gathering assets located in Tennessee; and (3) the revenues and gain on sale related to the Partnership s former 49% non-controlling interest in Laurel Mountain. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

The Pipeline segment consists of the Partnership s 20% interest in the equity income generated by WTLPG, which owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. Pipeline revenues are primarily derived from transportation fees.

Table of Contents

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

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
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	209,764	(10)		209,754
General and administrative[(1)] `			10,445	10,445
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 ventures		1,917		1,917
Net income	$ 25,899	$ 1,927	$ 47,025	$ 74,851
Three months ended June 30, 2011:				
Revenue:				
Revenues third party[(1)]	$ 344,996	$	$ 5,134	$ 350,130
Revenues affiliates	55			55
Total revenues	345,051		5,134	350,185
Costs and expenses:				
Operating costs and expenses	287,708	575		288,283
General and administrative[(1)]			8,655	8,655
Depreciation and amortization	19,123			19,123
Interest expense[(1)]			6,145	6,145
Total costs and expenses	306,831	575	14,800	322,206
Equity income in joint ventures		687		687
Loss on asset sale	(273)			(273)
Loss on early extinguishment of debt			(19,574)	(19,574)
Net income (loss)	$ 37,947	$ 112	$ (29,240)	$ 8,819

Table of Contents

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
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	456,897	73		456,970
General and administrative[1] `			20,390	20,390
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 ventures		2,813		2,813
Net income	$ 63,391	$ 2,740	$ 15,191	$ 81,322
Six Months Ended June 30, 2011:				
Revenue:				
Revenues third party[1]	$ 625,084	$	$ (18,213)	$ 606,871
Revenues affiliates	177			177
Total revenues	625,261		(18,213)	607,048
Costs and expenses:				
Operating costs and expenses	518,958	575		519,533
General and administrative[1]			17,672	17,672
Depreciation and amortization	38,028			38,028
Interest expense[1]			18,590	18,590
Total costs and expenses	556,986	575	36,262	593,823
Equity income	462	687		1,149
Gain on sale of assets	255,674			255,674
Loss on early extinguishment of debt			(19,574)	(19,574)
Net income (loss) from continuing operations	324,411	112	(74,049)	250,474
Loss from discontinued operations			(81)	(81)
Net income (loss)	$ 324,411	$ 112	$ (74,130)	$ 250,393

(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.

Capital Expenditures:	Three Months Ended June 30, 2012	2011	Six Months Ended June 30, 2012	2011
Gathering and Processing	$ 65,221	$ 73,636	$ 146,388	$ 91,969
Pipeline				
	$ 65,221	$ 73,636	$ 146,388	$ 91,969

Table of Contents

Balance Sheet	June 30, 2012	December 31, 2011
Investment in joint ventures:		
Pipeline	$ 86,092	$ 86,879
	$ 86,092	$ 86,879
Total assets:		
Gathering and processing	$ 1,922,090	$ 1,806,550
Pipeline	86,190	87,053
Corporate and other	92,122	37,209
	$ 2,100,402	$ 1,930,812

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,		Six Months Ended June 30,	
	2012	2011	2012	2011
Natural gas and liquids sales:				
Natural gas	$ 69,939	$ 104,813	$ 148,644	$ 186,657
NGLs	149,160	205,071	337,854	372,865
Condensate	21,925	21,641	44,023	37,198
Other	(2,223)	(1,357)	(2,495)	(243)
Total	$ 238,801	$ 330,168	$ 528,026	$ 596,477

Table of Contents

NOTE 17 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s 8.75% 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, 2012 and December 31, 2011 and for the three and six months ended June 30, 2012 and 2011 include the financial statements of 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. Under the terms of the 8.75% Senior Notes and the revolving credit facility, WestOK LLC and WestTX LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the 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, 2012 and December 31, 2011 and for the three and six months ended June 30, 2012 and 2011. 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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
June 30, 2012					
Assets					
Cash and cash equivalents	$	$ 257	$	$	$ 257
Accounts receivable affiliates	469,588	42,237		(511,825)	
Other current assets	524	56,815	87,346	(1,209)	143,476
Total current assets	470,112	99,309	87,346	(513,034)	143,733
Property, plant and equipment, net		295,239	1,409,795		1,705,034
Intangible assets, net		9,598	102,104		111,702
Investment in joint ventures		86,092			86,092
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,469,367	1,925,018		(3,394,385)	
Other assets, net	21,813	31,452	576		53,841
Total assets	$ 1,961,292	$ 2,446,708	$ 3,452,749	$ (5,760,347)	$ 2,100,402
Liabilities and Equity					
Accounts payable affiliates	$	$	$ 513,972	$ (511,825)	$ 2,147
Other current liabilities	1,539	23,518	99,453		124,510
Total current liabilities	1,539	23,518	613,425	(511,825)	126,657
Long-term debt, less current portion	701,084		7,981		709,065
Other long-term liability	118	11	6,000		6,129
Equity	1,258,551	2,423,179	2,825,343	(5,248,522)	1,258,551
Total liabilities and equity	$ 1,961,292	$ 2,446,708	$ 3,452,749	$ (5,760,347)	$ 2,100,402
December 31, 2011					
Assets					
Cash and cash equivalents	$	$ 168	$	$	$ 168
Accounts receivable affiliates	302,837	43,148		(345,985)	

Other current assets	151	30,486	103,414	(1,353)	132,698
Total current assets	302,988	73,802	103,414	(347,338)	132,866
Property, plant and equipment, net		275,514	1,292,314		1,567,828
Intangible assets, net			103,276		103,276
Investment in joint ventures		86,879			86,879
Long term notes receivable			1,852,928	(1,852,928)	
Equity investments	1,427,152	2,035,533		(3,462,685)	
Other assets, net	20,750	16,587	2,626		39,963
Total assets	$ 1,750,890	$ 2,488,315	$ 3,354,558	$ (5,662,951)	$ 1,930,812
Liabilities and Equity					
Accounts payable affiliates	$	$	$ 348,660	$ (345,985)	$ 2,675
Other current liabilities	1,551	32,410	135,770		169,731
Total current liabilities	1,551	32,410	484,430	(345,985)	172,406
Long-term debt, less current portion	512,983		9,072		522,055
Other long-term liability	128	(5)			123
Equity	1,236,228	2,455,910	2,861,056	(5,316,966)	1,236,228
Total liabilities and equity	$ 1,750,890	$ 2,488,315	$ 3,354,558	$ (5,662,951)	$ 1,930,812

Table of Contents

Statements of Operations and

Other Comprehensive Income

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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	73,790	82,540	25,015	(106,494)	74,851
Income attributable to non-controlling interest			(1,061)		(1,061)
Net income 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	$ 74,898	$ 83,648	$ 23,954	$ (107,602)	$ 74,898

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Three Months Ended June 30, 2011					
Total revenues	$	$ 74,135	$ 276,050	$	$ 350,185
Total costs and expenses	(4,710)	(75,434)	(242,062)		(322,206)
Equity income	32,443	34,749		(66,505)	687
Loss on asset sale		(273)			(273)
Loss on early extinguishment of debt	(19,574)				(19,574)
Net income	8,159	33,177	33,988	(66,505)	8,819
Income attributable to non-controlling interest			(1,545)		(1,545)
Preferred unit dividends	(149)				(149)
Net income attributable to common limited partners and the General Partner	8,010	33,177	32,443	(66,505)	7,125
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income	1,702	1,702		(1,702)	1,702
Comprehensive income	$ 9,712	$ 34,879	$ 32,443	$ (68,207)	$ 8,827

Table of Contents

Statements of Operations and

Other Comprehensive Income

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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	78,725	96,349	60,035	(153,787)	81,322
Income attributable to non-controlling interest			(2,597)		(2,597)
Net income 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	$ 80,979	$ 98,603	$ 57,438	$ (156,041)	$ 80,979
Six Months Ended June 30, 2011					
Total revenues	$	$ 107,180	$ 499,868	$	$ 607,048
Total costs and expenses	(15,804)	(140,338)	(437,681)		(593,823)
Equity income	284,115	62,897		(345,863)	1,149
Gain on asset sale		255,674			255,674
Loss on early extinguishment of debt	(19,574)				(19,574)
Income (loss) from continuing operations	248,737	285,413	62,187	(345,863)	250,474
Loss from discontinued operations		(81)			(81)
Net income	248,737	285,332	62,187	(345,863)	250,393
Income attributable to non-controlling interest			(2,732)		(2,732)
Preferred unit dividends	(389)				(389)
Net income attributable to common limited partners and the General Partner	248,348	285,332	59,455	(345,863)	247,272
Other comprehensive income:					
Adjustment for realized losses on derivatives reclassified to net income	3,404	3,404		(3,404)	3,404
Comprehensive income	$ 251,752	$ 288,736	$ 59,455	$ (349,267)	$ 250,676

Table of Contents

Statements of Cash Flows

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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

	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Six Months Ended June 30, 2011					
Net cash provided by (used in):					
Operating activities	$ (22,914)	$ 25,345	$ 110,425	$ (60,946)	$ 51,910
Continuing investing activities	297,280	277,260	(72,987)	(278,910)	222,643
Discontinued investing activities		(81)			(81)
Investing activities	297,280	277,179	(72,987)	(278,910)	222,562
Financing activities	(274,366)	(302,522)	(37,438)	339,856	(274,470)
Net change in cash and cash equivalents		2			2
Cash and cash equivalents, beginning of period		164			164
Cash and cash equivalents, end of period	$	$ 166	$	$	$ 166

Table of Contents

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, 2011. 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, 2011.

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 and processing services in the Anadarko 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 Pipeline Transportation.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins; (2) the natural gas gathering assets located in Tennessee; and (3) the revenues and gain on sale related to our former 49% interest in Laurel Mountain. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering and processing of natural gas.

Our Gathering and Processing operations, own, have interests in and operate seven natural gas processing plants with aggregate capacity of approximately 610 MMCFD, which are connected to approximately 9,000 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas. In addition, we own and operate approximately 100 miles of active natural gas gathering systems located in Tennessee. Our gathering systems gather gas from wells and central delivery points and deliver to natural gas processing plants, as well as third-party pipelines.

Our Pipeline Transportation operations consist of 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. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron Corporation, a Delaware corporation (Chevron NYSE: CVX), which owns the remaining 80% interest.

Table of Contents

Recent Events

In February 2012, we acquired a gas gathering system and related assets, within our WestOK system, for an initial net purchase price of $19.0 million. We 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. In connection with this acquisition, we received assignment of gas purchase agreements for gas currently gathered on the acquired system. We accounted for the acquisition as a business combination.

On May 31, 2012, we entered into an amendment to the revolving credit facility agreement, which among other changes: (1) increased the revolving credit facility from $450.0 million to $600.0 million; (2) extended the maturity date from December 22, 2015 to May 31, 2017; (3) reduced the Applicable Margin used to determine interest rates by 0.50%; (4) revised the negative covenants to (i) permit investments in joint ventures equal to the greater of 20% of Consolidated Net Tangible Assets (as defined in the Credit Agreement) or $340 million, provided the Partnership meets certain requirements, and (ii) increased the general investment basket to 5% of Consolidated Net Tangible Assets; (5) revised the definition of Consolidated EBITDA to provide for the inclusion of the first twelve months of projected revenues for identified capital expansion projects, upon completion of the projects; and (6) provided for the option of additional revolving credit commitments of up to $200.0 million.

In June 2012, we completed construction of, and started processing through, a 60 MMCFD cryogenic facility at the Velma gas plant, increasing capacity at Velma to 160 MMCFD. This expansion supports our long-term fee-based agreement with XTO Energy, Inc., a subsidiary of ExxonMobil, to provide natural gas gathering and processing services for up to an incremental 60 MMCFD from the Woodford Shale.

In June 2012, we acquired a gas gathering system and related assets in the Barnett Shale play in Tarrant County, Texas for an initial net purchase price of $18.0 million. The system consists of 19 miles of gathering pipeline that is used to facilitate gathering some of the newly acquired production for our affiliate, Atlas Resources Partners, L.P. (ARP). We accounted for the acquisition as a business combination.

How We Evaluate Our Operations

Our principal revenue is generated from the gathering and 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 and NGLs 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 and process, 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 and process and the NGLs and condensate we recover and sell, which is a function of the relevant supply and demand in the mid-continent, mid-Atlantic 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 plants.

Revenue consists of the sale of natural gas and NGLs and the fees earned from our gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems and then sell the natural gas and NGLs 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, 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 and processing 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 and 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, compression and other fees less purchased product costs, subject to certain non-cash adjustments. Product costs include the cost of natural gas and NGLs 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 our 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 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.

Table of Contents

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, 2012 and 2011 (in thousands):

RECONCILIATION OF GROSS MARGIN

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Net income	$ 74,851	$ 8,819	$ 81,322	$ 250,393
Derivative (gain) loss, net[(1)]	(67,847)	(6,837)	(55,812)	14,808
Other income, net[(1)]	(2,588)	(2,745)	(5,003)	(5,534)
Operating expenses[(2)]	14,812	13,532	28,957	26,490
General and administrative expense[(3)]	10,445	8,655	20,390	17,672
Other costs	(161)	575	(195)	575
Depreciation and amortization	21,712	19,123	42,554	38,028
Interest	9,269	6,145	17,977	18,590
Equity income in joint ventures	(1,917)	(687)	(2,813)	(1,149)
(Gain) loss on asset sale[(4)]		273		(255,593)
Loss on early extinguishment of debt		19,574		19,574
Non-cash linefill (gain) loss[(5)]	2,223	1,357	2,495	243
Gross margin	$ 60,799	$ 67,784	$ 129,872	$ 124,097

Table of Contents

RECONCILIATION OF EBITDA, ADJUSTED EBITDA AND DISTRIBUTABLE CASH FLOW

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Net income	$ 74,851	$ 8,819	$ 81,322	$ 250,393
Income attributable to non-controlling interests(6)	(1,061)	(1,545)	(2,597)	(2,732)
Interest expense	9,269	6,145	17,977	18,590
Depreciation and amortization	21,712	19,123	42,554	38,028
EBITDA	104,771	32,542	139,256	304,279
Equity income in joint ventures	(1,917)	(687)	(2,813)	(1,149)
Distributions from joint ventures	1,800		3,600	1,764
(Gain) loss on asset sale		273		(255,593)
Loss on early extinguishment of debt		19,574		19,574
Non-cash (gain) loss on derivatives	(64,741)	(13,788)	(54,045)	4,572
Premium expense on derivative instruments	3,984	3,710	7,736	6,715
Non-cash compensation	2,940	502	3,918	1,679
Non-cash line fill (gain) loss(5)	2,223	1,357	2,495	243
Adjusted EBITDA	49,060	43,483	100,147	82,084
Interest expense	(9,269)	(6,145)	(17,977)	(18,590)
Amortization of deferred finance costs	1,130	1,034	2,295	2,301
Preferred dividend obligation		(149)		(389)
Proceeds remaining from asset sale(7)				5,850
Premium expense on derivative instruments	(3,984)	(3,710)	(7,736)	(6,715)
Other costs	(161)	575	(195)	575
Maintenance capital	(4,000)	(5,211)	(8,510)	(8,471)
Distributable Cash Flow	$ 32,776	$ 29,877	$ 68,024	$ 56,645

(1) Adjusted to separately present derivative gain (losses) instead of combining these amounts in other income, net.
(2) Operating expenses include plant operating expenses; and transportation and compression expenses.
(3) General and administrative includes compensation reimbursement to affiliates.
(4) Represents the gain on sale of Laurel Mountain and an adjustment to the gain on sale of our Elk City system.
(5) Represents the non-cash impact of commodity price movements on pipeline linefill.
(6) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems.
(7) Net proceeds remaining from the sale of Laurel Mountain after repayment of the amount outstanding on our revolving credit facility, redemption of our 8.125% Senior Notes due 2015 and purchase of certain 8.75% Senior Notes due 2018.

Table of Contents

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, 2012	Three Months Ended June 30, 2011	Percent Change	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Percent Change
Pricing:						
Weighted Average Market Prices:						
NGL price per gallon Conway hub	$ 0.70	$ 1.16	(39.7)%	$ 0.82	$ 1.12	(26.8)%
NGL price per gallon Mt. Belvieu hub	0.94	1.34	(29.9)%	1.06	1.27	(16.5)%
Natural gas sales ($/Mcf):						
Velma	2.04	4.11	(50.4)%	2.29	4.05	(43.5)%
WestOK	2.09	4.14	(49.5)%	2.30	4.05	(43.2)%
WestTX	1.85	4.12	(55.1)%	2.18	4.03	(45.9)%
Weighted Average	2.01	4.13	(51.3)%	2.26	4.05	(44.2)%
NGL sales ($/gallon):						
Velma	0.71	1.16	(38.8)%	0.82	1.10	(25.5)%
WestOK	0.79	1.17	(32.5)%	0.85	1.12	(24.1)%
WestTX	0.88	1.36	(35.3)%	1.03	1.28	(19.5)%
Weighted Average	0.80	1.25	(36.0)%	0.92	1.18	(22.0)%
Condensate sales ($/barrel):						
Velma	93.69	101.57	(7.8)%	98.52	96.51	2.1%
WestOK	85.41	93.68	(8.8)%	90.00	89.29	0.8%
WestTX	86.17	100.42	(14.2)%	91.11	96.66	(5.7)%
Weighted Average	87.00	98.23	(11.4)%	91.95	93.79	(2.0)%
Operating data:						
Velma system:						
Gathered gas volume (MCFD)	136,553	102,159	33.7%	132,888	96,418	37.8%
Processed gas volume (MCFD)	129,070	96,625	33.6%	125,987	90,923	38.6%
Residue gas volume (MCFD)	106,424	78,381	35.8%	103,380	74,072	39.6%
NGL volume (BPD)	14,220	11,367	25.1%	13,931	10,722	29.9%
Condensate volume (BPD)	434	442	(1.8)%	499	486	2.7%
WestOK system:						
Gathered gas volume (MCFD)	336,377	260,250	29.3%	315,787	252,257	25.2%
Processed gas volume (MCFD)	315,753	247,868	27.4%	297,529	238,925	24.5%
Residue gas volume (MCFD)	291,225	230,605	26.3%	271,582	214,711	26.5%
NGL volume (BPD)	14,379	13,204	8.9%	14,220	13,397	6.1%
Condensate volume (BPD)	1,209	884	36.8%	1,307	871	50.1%
WestTX system[(1)]:						
Gathered gas volume (MCFD)	267,395	204,515	30.7%	256,867	195,268	31.5%
Processed gas volume (MCFD)	236,213	193,714	21.9%	233,359	183,323	27.3%
Residue gas volume (MCFD)	164,593	133,012	23.7%	162,308	124,512	30.4%
NGL volume (BPD)	32,755	29,147	12.4%	32,928	28,316	16.3%
Condensate volume (BPD)	1,941	1,827	6.2%	1,440	1,428	0.8%
Tennessee system:						
Average throughput volumes (MCFD)	8,348	7,675	8.8%	8,286	7,876	5.2%
WTLPG system[(1)]:						
Average NGL volumes (BPD)	243,708	230,913	5.5%	243,013	227,087	7.0%

(1) Operating data for WestTX and WTLPG represent 100% of the operating activity for the respective systems.

47

Table of Contents

Three Months Ended June 30, 2012 Compared to Three Months Ended June 30, 2011

The following table and discussion is a summary of our consolidated results of operations for the three months ended June 30, 2012 and 2011 (in thousands):

	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011[(1)]	Variance	Percent Change
Gross margin[(2)]				
Natural gas and liquids sales	$ 238,801	$ 330,168	$ (91,367)	(27.7)%
Transportation, processing and other fees	14,878	10,435	4,443	42.6%
Less: non-cash line fill gain (loss)[(3)]	(2,223)	(1,357)	(866)	(63.8)%
Less: natural gas and liquids cost of sales	195,103	274,176	(79,073)	(28.8)%
Gross margin	60,799	67,784	(6,985)	(10.3)%
Expenses:				
Operating expenses	14,651	14,107	544	3.9%
General and administrative[(4)]	10,445	8,655	1,790	20.7%
Depreciation and amortization	21,712	19,123	2,589	13.5%
Interest expense	9,269	6,145	3,124	50.8%
Total expenses	56,077	48,030	8,047	16.8%
Other income items:				
Derivative gain (loss), net[(1)]	67,847	6,837	61,010	892.4%
Other income, net[(1)]	2,588	2,745	(157)	(5.7)%
Non-cash line fill gain (loss)[(3)]	(2,223)	(1,357)	(866)	(63.8)%
Equity income in joint ventures	1,917	687	1,230	179.0%
Loss on asset sale[(5)]		(273)	273	100.0%
Loss on extinguishment of debt		(19,574)	19,574	100.0%
Income attributable to non-controlling interests[(6)]	(1,061)	(1,545)	484	31.3%
Preferred unit dividends		(149)	149	100.0%
Net income attributable to common limited partners and General Partner	$ 73,790	$ 7,125	$ 66,665	935.6%
Non-GAAP financial data:				
EBITDA[(2)]	$ 104,771	$ 32,542	$ 72,229	222.0%
Adjusted EBITDA[(2)]	49,060	43,483	5,577	12.8%
Distributable cash flow[(2)]	32,776	29,877	2,899	9.7%

(1) Adjusted to separately present derivative gain (losses) instead of combining these amounts in other income, net.
(2) 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).
(3) Includes the non-cash impact of commodity price movements on pipeline linefill.
(4) General and administrative also includes any compensation reimbursement to affiliates.
(5) Represents expenses related to Laurel Mountain sale.
(6) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems.

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, 2012 decreased primarily due to lower natural gas and NGL sales prices partially offset by higher production volumes.

Volumes on the Velma system increased for the three months ended June 30, 2012 when compared to the prior year period primarily due to increased production gathered on the Madill-to-Velma gas gathering pipeline.

Volumes on the WestOK system increased for the three months ended June 30, 2012 compared to the prior year primarily due to increased production gathered on the previously expanded gathering systems.

WestTX system gathering and processing volumes for the three months ended June 30, 2012 increased when 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. NGL volumes for the three months ended June 30, 2012 increased at a lower rate than processed volumes when compared to the prior year period due to the negative impact of the planned maintenance of a third-party fractionator at Mont Belvieu resulting in reduced NGL production during the quarter, including the rejection of ethane in order to meet reduced allocated NGL volumes.

Transportation, processing and other fees for the three months ended June 30, 2012 increased primarily due to increased processing fee revenue on the WestOK and Velma systems related to the increased volumes gathered on the systems.

Expenses:

Operating expenses, comprised of plant operating expenses; transportation and compression expenses; and other costs for the three months ended June 30, 2012 increased primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin.

General and administrative expense, including amounts reimbursed to affiliates, increased for the three months ended June 30, 2012 mainly due to increased non-cash compensation expense and an increase in the allocation from our General Partner for compensation and benefits related to its employees who perform services for us.

Depreciation and amortization expense for the three months ended June 30, 2012 increased primarily due to expansion capital expenditures incurred subsequent to June 30, 2011.

Interest expense for the three months ended June 30, 2012 increased primarily due to (1) a $3.1 million increase in interest expense associated with the 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes); and (2) a $1.2 million increase in interest associated with the revolving credit facility; partially offset by a $0.9 million increase in capitalized interest. The increased interest on the 8.75% Senior Notes is due to the issuance of additional 8.75% Senior Notes in November 2011. The increased interest on the revolving credit facility is due to additional borrowings in the current period to cover current capital expenditures. The increased capitalized interest is due to the increased capital expenditures in the current period (see Capital Requirements).

Other income items:

Derivative gain (loss), net had a favorable variance for the three months ended June 30, 2012 mainly due to a $51.1 million increased gain on the fair value revaluation of commodity derivative contracts in the current period compared to the prior year period combined with a $9.9 million favorable variance for realized settlements in the current period mainly as a result of lower NGL prices. 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 10 for further discussion of derivative instrument valuations). We recognized a $51.5 million mark-to-market gain and a $2.4 million mark-to-market loss on derivatives, which were valued upon unobservable inputs for the three months ended June 30, 2012 and 2011, 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.

Other income, net for the three months ended June 30, 2012 decreased compared to the prior year period primarily due to lower interest income, partially due to the December 2011 settlement of a note receivable from The Williams Companies, Inc. (NYSE: WMB) related to our former 49% non-controlling ownership interest in Laurel Mountain, which we sold in February 2011.

Non-cash line fill gain (loss) had an unfavorable variance for the three months ended June 30, 2012 compared to the prior year period primarily due to an increased loss recognized on the revaluation of line fill due to decreased NGL prices.

Equity income in joint ventures increased for the three months ended June 30, 2012 primarily due to three full months of equity earnings generated in the current period from our 20% ownership interest in WTPLG compared to equity earnings in only a portion of the prior year period due to the purchase of our ownership interest in May 2011.

Loss on asset sales for the three months ended June 30, 2011 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011.

Loss on early extinguishment of debt for the three months ended June 30, 2011 represents the premium paid for the redemption of the 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes) and the recognition of deferred finance costs related to the redemption (see Senior Notes).

Income attributable to non-controlling interests decreased primarily due to lower net income for the WestOK and WestTX joint ventures, which were formed to accomplish our acquisition of control of the systems. The decrease in net income of the joint ventures was principally due to lower gross margins on the sale of commodities, resulting from lower prices. The non-controlling interest expense represents Anadarko Petroleum Corporation s interest in the net income of the WestOK and WestOK joint ventures.

Preferred unit dividends for the three months ended June 30, 2011 represent dividends paid on the then outstanding 8,000 units of 12% Cumulative Class C Preferred Units, which were redeemed in 2011.

Non-GAAP financial data:

EBITDA was higher for the three months ended June 30, 2012 compared to the prior year period mainly due to the favorable derivative gain recognized during the three months ended June 30, 2011, as discussed above in Other income items ; and due to the impact of the loss on early extinguishment of debt recorded in the prior year period as discussed above in Other income items .

Table of Contents

Adjusted EBITDA had a favorable variance for the three months ended June 30, 2012 compared to the prior year period partially due to the favorable variance of the cash portion of the derivative gain, as discussed above in Other income items ; and a $1.8 million distribution received from joint ventures during the three months ended June 30, 2012; partially offset by a lower gross margin variance, as discussed above in Gross margin .

Distributable cash flow had a favorable variance for the three months ended June 30, 2012 compared to the prior year period due to the favorable variance of Adjusted EBITDA, partially offset by higher interest expense, as discussed above in Expenses .

Six Months Ended June 30, 2012 Compared to Six Months Ended June 30, 2011

The following table and discussion is a summary of our consolidated results of operations for the six months ended June 30, 2012 and 2011 (in thousands):

	Six Months Ended June 30,			Percent
	2012	**2011[1]**	**Variance**	**Change**
Gross margin[2]				
Natural gas and liquids sales	$ 528,026	$ 596,477	$ (68,451)	(11.5)%
Transportation, processing and other fees	27,559	19,845	7,714	38.9%
Less: non-cash line fill gain (loss)[3]	(2,495)	(243)	(2,252)	(926.7)%
Less: natural gas and liquids cost of sales	428,208	492,468	(64,260)	(13.0)%
Gross margin	129,872	124,097	5,775	4.7%
Expenses:				
Operating expenses	28,762	27,065	1,697	6.3%
General and administrative[4]	20,390	17,672	2,718	15.4%
Depreciation and amortization	42,554	38,028	4,526	11.9%
Interest expense	17,977	18,590	(613)	(3.3)%
Total expenses	109,683	101,355	8,328	8.2%
Other income items:				
Derivative gain (loss), net[1]	55,812	(14,808)	70,620	476.9%
Other income, net[1]	5,003	5,534	(531)	(9.6)%
Non-cash line fill gain (loss)[3]	(2,495)	(243)	(2,252)	(926.7)%
Equity income in joint ventures	2,813	1,149	1,664	144.8%
Gain on asset sales and other[5]		255,593	(255,593)	(100.0)%
Loss on early extinguishment of debt		(19,574)	19,574	100.0%
Income attributable to non-controlling interests[6]	(2,597)	(2,732)	135	4.9%
Preferred unit dividends		(389)	389	100.0%
Net income attributable to common limited partners and General Partner	$ 78,725	$ 247,272	$ (168,547)	(68.2)%

Table of Contents

	Six Months Ended June 30, 2012	2011(1)	Variance	Percent Change
Non-GAAP financial data:				
EBITDA(2)	$ 139,256	$ 304,279	$ (165,023)	(54.2)%
Adjusted EBITDA(2)	100,147	82,084	18,063	22.0%
Distributable cash flow(2)	68,024	56,645	11,379	20.1%

(1) Adjusted to separately present derivative gain (losses) instead of combining these amounts in other income, net.
(2) 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).
(3) Includes the non-cash impact of commodity price movements on pipeline linefill.
(4) General and administrative also includes any compensation reimbursement to affiliates.
(5) Represents the gain on sale Laurel Mountain and an adjustment to the gain on sale of our Elk City system.
(6) Represents Anadarko s non-controlling interest in the operating results of the WestOK and WestTX systems.

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, 2012 increased primarily due to higher production volumes offset by lower natural gas and NGL sales prices.

Volumes on the Velma system increased for the six months ended June 30, 2012 compared to the prior year period primarily due to increased production gathered on the Madill-to-Velma gas gathering pipeline.

Volumes on the WestOK system increased for the six months ended June 30, 2012 compared to the prior year primarily due to increased production gathered on the previously expanded gathering systems.

WestTX system gathering and processing volumes for the six months ended June 30, 2012 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.

Transportation, processing and other fees for the six months ended June 30, 2012 increased primarily due to increased processing fee revenue on the WestOK and Velma systems related to the increased volumes gathered on the systems.

Expenses:

Operating expenses, comprised of plant operating expenses; transportation and compression expenses; and other costs, for the six months ended June 30, 2012 increased primarily due to increased gathered volumes in comparison to the prior year period, as discussed above in Gross margin.

General and administrative expense, including amounts reimbursed to affiliates, increased for the six months ended June 30, 2012 mainly due to increased non-cash compensation expense and an increase in the allocation from our General Partner for compensation and benefits related to its employees who perform services for us.

Table of Contents

Depreciation and amortization expense for the six months ended June 30, 2012 increased primarily due to expansion capital expenditures incurred subsequent to June 30, 2011.

Interest expense for the six months ended June 30, 2012 decreased primarily due to a $6.0 million decrease in interest expense associated with the 8.125% Senior Notes; and a $2.9 million increase in capitalized interest; offset by a $6.0 million increase in interest expense associated with the 8.75% Senior Notes; and a $2.1 million increase in interest associated with the revolving credit facility. The lower interest expense on our 8.125% Senior Notes is due to the redemption of the 8.125% Senior Notes in April 2011 with proceeds from the sale of our 49% non-controlling interest in Laurel Mountain. The increased capitalized interest is due to the increased capital expenditures in the current period (see Capital Requirements). The increased interest on the 8.75% Senior Notes is due to the issuance of additional 8.75% Senior Notes in November 2011. The increased interest on the revolving credit facility is due to additional borrowings in the current period to cover the current capital expenditures.

Other income items:

Derivative gain (loss), net had a favorable variance for the six months ended June 30, 2012 mainly due to a $58.9 million favorable variance on the fair value revaluation of commodity derivative contracts in the current period compared to the prior year period combined with a $11.7 million favorable variance for realized settlements in the current period mainly as a result of lower NGL prices. 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 10 for further discussion of derivative instrument valuations). We recognized a $44.4 million mark-to-market gain and a $12.3 million mark-to-market loss on derivatives, which were valued upon unobservable inputs for the six months ended June 30, 2012 and 2011, 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.

Other income, net for the six months ended June 30, 2012 decreased compared to the prior year period primarily due to lower interest income, which is partially due to the December 2011 settlement of a note receivable from The Williams Companies, Inc. (NYSE: WMB) related to our former 49% non-controlling ownership interest in Laurel Mountain, which we sold in February 2011.

Non-cash line fill gain (loss) had an unfavorable variance for the six months ended June 30, 2012 compared to the prior year period primarily due to an increased loss recognized on the revaluation of line fill due to decreased NGL prices.

Equity income in joint ventures increased for the six months ended June 30, 2012 primarily due to a full six months of equity earnings generated in the current period from our 20% ownership interest in WTPLG compared to equity earnings for only a portion of the prior year period due to the purchase of our ownership interest in May 2011.

Gain on asset sales and other for the six months ended June 30, 2011 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011.

Table of Contents

Preferred unit dividends for the six months ended June 30, 2011 represent dividends paid on the then outstanding 8,000 units of 12% Cumulative Class C Preferred Units, which were redeemed in 2011.

Non-GAAP financial data:

EBITDA was lower for the six months ended June 30, 2012 compared to the prior year period mainly due to the gain on sale of assets recognized during the six months ended June 30, 2011, as discussed above in Other income items ; partially offset by the favorable derivative gain recognized during the six months ended June 30, 2011, as discussed above in Other income items ; and the impact of the loss on early extinguishment of debt recorded in the prior year period as discussed above in Other income items .

Adjusted EBITDA and Distributable cash flow had favorable variances for the six months ended June 30, 2012 compared to the prior year period partially due to the favorable variance of the cash portion of the derivative gain, as discussed above in Other income items ; a higher gross margin variance, as discussed above in Gross margin ; and a $1.8 million higher distribution received from joint ventures during the six months ended June 30, 2012 compared to the prior year period.

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, 2012, we had $330.5 million outstanding borrowings under our $600.0 million senior secured revolving credit facility and $0.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with $269.4 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, 2012. We had a working capital surplus of $17.1 million at June 30, 2012 compared with a $39.5 million working capital deficit at December 31, 2011. 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 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 raise capital and reduce the amount of cash available to fund our operations. We rely on our cash flows

Table of Contents

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, 2012 Compared to Six Months Ended June 30, 2011

The following table details the cash flow changes between the six months ended June 30, 2012 and 2011 (in thousands):

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011	Variance	Percent Change
Net cash provided by (used in):				
Operating activities	$ 64,531	$ 51,910	$ 12,621	24.3%
Investing activities	(182,827)	222,562	(405,389)	(182.1)%
Financing activities	118,385	(274,470)	392,855	143.1%
Net change in cash and cash equivalents	$ 89	$ 2	$ 87	

Net cash provided by operating activities for the six months ended June 30, 2012 increased compared to the prior year period due to a $29.4 million increase in net earnings from continuing operations excluding non-cash charges offset by a $16.8 million unfavorable variance in the change in working capital. The increase in net earnings from continuing operations excluding non-cash charges is primarily due to favorable derivative settlements in the current period compared to the prior year period (see Results of Operations).

Net cash provided by (used in) investing activities for the six months ended June 30, 2012 had an unfavorable variance compared to the prior year period mainly due to (1) net proceeds of $411.5 million received from the sale of Laurel Mountain in the prior period; (2) a $54.4 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); and (3) $36.7 million cash paid for acquisition of assets in the current period, partially offset by $85.0 million paid to acquire the interest in WTLPG in the prior year period and $12.3 million cash paid in capital contributions to Laurel Mountain in the prior year period.

Net cash provided by (used in) financing activities for the six months ended June 30, 2012 had a favorable variance compared to the prior year period mainly due to (1) $293.9 million used in the prior year period to redeem the 8.125% Senior Notes and a portion of the 8.75% Senior Notes; (2) $188.5 million provided by additional borrowings on our revolving credit facility in the current period for capital expenditures; and (3) $72.5 million used in the prior period to reduce outstanding borrowings on the revolving credit facility, partially offset by $21.7 million increased distributions paid in the current year compared to the prior year period. The gross amount of borrowings and repayments under the revolving credit facility included within net cash provided by (used in) financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of (i) cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under the revolving credit facility, and (ii) payments, which generally occur throughout the period and increase borrowings under the revolving credit facility, which is generally common practice for the industry.

Table of Contents

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,	
	2012	2011	2012	2011
Expansion capital expenditures	$ 61,221	$ 68,425	$ 137,878	$ 83,498
Maintenance capital expenditures	4,000	5,211	8,510	8,471
Total	$ 65,221	$ 73,636	$ 146,388	$ 91,969

Expansion capital expenditures increased for the six months ended June 30, 2012 compared to the prior year period primarily due to current major processing facility expansions, compressor upgrades and pipeline projects, including a 60 MMCFD expansion at the Velma system, which was placed in service in June 2012; a 200 MMCFD expansion at the WestOK system scheduled to be placed in service in the second half of 2012; and construction of a 100 MMCFD plant in the WestTX system scheduled to be placed in service in the first half of 2013. The decrease in maintenance capital expenditures for the three months ended June 30, 2012 when compared with the prior year period was due to fluctuations in the timing of scheduled maintenance activity. As of June 30, 2012, we had approved additional expenditures of approximately $179.1 million on processing facility expansions, pipeline extensions and compressor station upgrades, of which approximately $106.8 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 and our General Partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all 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% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2% of the aggregate amount of cash being distributed. 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 $1.6 million and $3.0 million were paid during the three and six months ended June 30, 2012, respectively. No incentive distributions were paid during the six months ended June 30, 2011.

Off Balance Sheet Arrangements

As of June 30, 2012, our off balance sheet arrangements include our letters of credit, issued under the provisions of our revolving credit facility, totaling $0.1 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.

Revolving Credit Facility

At June 30, 2012, 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, 2012, was 2.7%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $0.1 million was outstanding at June 30, 2012. These outstanding letter of credit amounts were not reflected as borrowings on our consolidated balance sheets.

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 and WestTX joint ventures. 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, 2012, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At June 30, 2012, we had $370.6 million principal amount outstanding of 8.75% Senior Notes, including a net $4.8 million unamortized premium. Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% 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 8.75% Senior Notes are junior in right of payment to our secured debt, including our obligations under our revolving credit facility.

The indenture governing the 8.75% Senior Notes contains 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, 2012.

On April 7, 2011, we redeemed $7.2 million of the 8.75% Senior Notes, which were tendered upon our offer to purchase the 8.75% Senior Notes, at par. The sale of our 49% non-controlling interest in Laurel Mountain on February 17, 2011 constituted an Asset Sale pursuant to the terms of the indenture of the 8.75% Senior Notes. As a result of the Asset Sale, we offered to purchase any and all of the 8.75% Senior Notes.

On April 8, 2011, we redeemed all the 8.125% Senior Notes. The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. We paid $293.7 million to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. In addition, we recorded $5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of the 8.125% Senior Notes and a partial redemption of the 8.75% Senior Notes.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions 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 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, 2011.

Table of Contents

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 based on 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, customer contracts and any other significant assets or liabilities. 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 differ from assumptions made, 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.
Impairment of Long-Lived Assets Management evaluates our long-lived assets, including intangibles, for impairment when events or changes in circumstances warrant such a review. A long-lived asset is considered impaired when the estimated undiscounted cash flow from such asset is less than the asset s carrying value. In that event, a loss is recognized to the extent that the carrying value exceeds the fair value of the long-lived asset. Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions.	In evaluating impairment, management considers the use or disposition of an asset, the estimated remaining life of an asset, and future expenditures to maintain an asset s existing service potential. In order to determine the cash flow, management must make certain estimates and assumptions, which include, but are not limited to, changes in general economic conditions in regions in which we operate, our ability to negotiate favorable contracts, the risks that natural gas exploration and production activities will not occur or be successful, competition from other midstream companies, our dependence on certain significant customers and producers of natural gas, and the volume of reserves behind an asset and future NGL product and natural gas prices.	As of June 30, 2012, there were no indicators of impairment for any of our assets. A significant variance in any of these assumptions or factors could materially affect future cash flows, which could result in the impairment of an asset. Recent increases in natural gas drilling has driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas and NGL prices may result in impairment charges in future periods.

Table of Contents

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 natural gas liquids 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.	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 $67.0 million and $16.5 million net derivative assets at June 30, 2012 and December 31, 2011, respectively, we had $53.0 million and $16.5 million net derivative assets at June 30, 2012 and December 31, 2011, 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, 2012 would have resulted in an $8.4 million noncash change to net income for the six months ended June 30, 2012.

Recently Adopted Accounting Standards

See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Recently Adopted Accounting Standards for information regarding adoption of recent 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, 2012. 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, 2012, we had a $600.0 million senior secured revolving credit facility with $330.5 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 2.7% at June 30, 2012. 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 $3.3 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 9 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 3, 2012, were $0.74 per gallon, $3.29 per million BTU and $89.18 per barrel, respectively. A 10% change in these prices would change our forecasted net income for the twelve-month period ended June 30, 2013 by approximately $3.1 million.

Table of Contents

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 recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our General Partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner s Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2012, 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.

Table of Contents

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, 2011.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Purchase and Sale Agreement, by and among Atlas Pipeline Partners, L.P., APL Laurel Mountain, LLC, Atlas Energy, Inc., and Atlas Energy Resources, LLC, dated November 8, 2010 (13)
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)
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)
4.3	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.
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(25)
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)
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(26)

10.4	Long-Term Incentive Plan[21]
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 Grant of Phantom Units to Non-Employee Managers[11]
10.9	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan[10]
10.10	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement[10]
10.11	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010[13]
10.12	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010[20]
10.13	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010[20]

Exhibit No.	Description
10.14	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[24]
10.15	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[24]
10.16	Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011[21]
10.17	Employment Agreement between Atlas Energy, L.P., Atlas Pipeline Partners, L.P. and Patrick J. McDonie dated as of July 3, 2012
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[27]
101.SCH	XBRL Schema Document[27]
101.CAL	XBRL Calculation Linkbase Document[27]
101.LAB	XBRL Label Linkbase Document[27]
101.PRE	XBRL Presentation Linkbase Document[27]
101.DEF	XBRL Definition Linkbase Document[27]

(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 annual report on Form 10-K filed for the year ended December 31, 2009.
(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) [Intentionally omitted]
(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 annual report on Form 10-K filed for the year ended December 31, 2011.
(26) Previously filed as an exhibit to current report on Form 8-K filed on May 31, 2012.
(27) 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.

Table of Contents

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 7, 2012	By: /s/ EUGENE N. DUBAY Eugene N. Dubay Chief Executive Officer, President and Managing Board Member of the General Partner
Date: August 7, 2012	By: /s/ ROBERT W. KARLOVICH, III Robert W. Karlovich, III Chief Financial Officer and Chief Accounting Officer of the General Partner