ATLAS PIPELINE PARTNERS LP
Form 10-Q
May 04, 2011
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 March 31, 2011

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.)**
1550 Coraopolis Heights Road Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	**(Zip code)**

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant 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 ¨ No ¨

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

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

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

The number of common units of the registrant outstanding on May 2, 2011 was 53,498,910.

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.
Fractionation	The process used to separate an NGL stream into its individual components.
Keep-Whole	Contract with producer whereby plant operator pays for or returns gas having an equivalent BTU content to the gas received at the well-head.
L.P.	Limited Partner or Limited Partnership
MCF	Thousand cubic feet
MCFD	Thousand cubic feet per day
MMBTU	Million British thermal units
MMCFD	Million cubic feet per day
NGL(s)	Natural Gas Liquid(s), primarily ethane, propane, normal butane, isobutane and natural gasoline
Percentage of Proceeds, (POP)	Contract with natural gas producers whereby the plant operator retains a negotiated percentage of the sale proceeds.
Residue gas	The portion of natural gas remaining after natural gas is processed for removal of NGLs and impurities.
SEC	Securities and Exchange Commission
Y-grade	A term utilized in the industry for the NGL stream prior to fractionation, also referred to as raw mix.

Table of Contents

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS (Unaudited)

(in thousands)

	March 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 167	$ 164
Funds held in escrow	7,026	
Accounts receivable	102,457	99,759
Current portion of derivative asset	158	
Prepaid expenses and other	17,296	15,118
Total current assets	127,104	115,041
Property, plant and equipment, net	1,348,671	1,341,002
Intangible assets, net	120,603	126,379
Investment in joint venture		153,358
Long-term note receivable	8,500	
Long-term funds held in escrow	286,670	
Other assets, net	27,704	29,068
Total assets	$ 1,919,252	$ 1,764,848
LIABILITIES AND EQUITY		
Current liabilities:		
Current portion of long-term debt	$ 213	$ 210
Accounts payable affiliates	2,001	12,280
Accounts payable	20,692	29,382
Accrued liabilities	21,605	30,013
Accrued interest payable	12,454	1,921
Current portion of derivative liability	16,851	4,564
Accrued producer liabilities	77,173	72,996
Distribution payable	240	240
Total current liabilities	151,229	151,606
Long-term portion of derivative liability	7,217	5,608
Long-term debt, less current portion	495,857	565,764
Other long-term liability	159	223
Commitments and contingencies		
Equity:		
General Partner s interest	24,495	20,066
Class C preferred limited partner s interest	8,000	8,000

Common limited partners interests	1,274,391	1,057,342
Accumulated other comprehensive loss	(9,522)	(11,224)
Total partners capital	1,297,364	1,074,184
Non-controlling interest	(32,574)	(32,537)
Total equity	1,264,790	1,041,647
Total liabilities and equity	$ 1,919,252	$ 1,764,848

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(in thousands, except per unit data)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Revenue:		
Natural gas and liquids	$ 266,309	$ 223,338
Transportation, compression and other fees third parties	9,288	9,919
Transportation, compression and other fees affiliates	122	176
Other income (loss), net	(18,856)	6,720
Total revenue and other income (loss), net	256,863	240,153
Costs and expenses:		
Natural gas and liquids	218,292	179,759
Plant operating	12,774	11,959
Transportation and compression	184	189
General and administrative	8,598	9,376
Compensation reimbursement affiliates	419	375
Depreciation and amortization	18,905	18,457
Interest	12,445	26,403
Total costs and expenses	271,617	246,518
Equity income in joint venture	462	1,462
Gain on asset sales and other	255,947	
Income (loss) from continuing operations	241,655	(4,903)
Loss on sale of discontinued operations	(81)	
Earnings of discontinued operations		6,781
Income (loss) from discontinued operations	(81)	6,781
Net income	241,574	1,878
Income attributable to non-controlling interests	(1,187)	(1,317)
Preferred unit dividends	(240)	
Net income attributable to common limited partners and the General Partner	$ 240,147	$ 561

5

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(in thousands, except per unit data)

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010
Allocation of net income (loss) attributable to:		
Common limited partners interest:		
Continuing operations	$ 235,399	$ (6,101)
Discontinued operations	(79)	6,651
	235,320	550
General Partner s interest:		
Continuing operations	4,829	(119)
Discontinued operations	(2)	130
	4,827	11
Net income (loss) attributable to:		
Continuing operations	240,228	(6,220)
Discontinued operations	(81)	6,781
	$ 240,147	$ 561
Net income (loss) attributable to common limited partners per unit:		
Basic:		
Continuing operations	$ 4.37	$ (0.12)
Discontinued operations		0.13
	$ 4.37	$ 0.01
Diluted:		
Continuing operations	$ 4.37	$ (0.12)
Discontinued operations		0.13
	$ 4.37	$ 0.01
Weighted average common limited partner units outstanding:		
Basic	53,375	52,849
Diluted	53,846	52,849

See accompanying notes to consolidated financial statements

6

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY (Unaudited)

FOR THE THREE MONTHS ENDED MARCH 31, 2011

(in thousands, except unit data)

	Number of Limited Partner Units Class C Preferred	Number of Limited Partner Units Common	Class C Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
Balance at January 1, 2011	8,000	53,338,010	$ 8,000	$ 1,057,342	$ 20,066	$ (11,224)	$ (32,537)	$ 1,041,647
Distributions paid			(240)	(19,916)	(398)		(1,224)	(21,778)
Issuance of units under incentive plans		156,900		468				468
Unissued units under incentive plans				1,177				1,177
Other comprehensive income						1,702		1,702
Net income			240	235,320	4,827		1,187	241,574
Balance at March 31, 2011	8,000	53,494,910	$ 8,000	$ 1,274,391	$ 24,495	$ (9,522)	$ (32,574)	$ 1,264,790

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)

(in thousands)

	Three Months Ended March 31,	
	2011	**2010**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 241,574	$ 1,878
Less: Income (loss) from discontinued operations	(81)	6,781
Net income (loss) from continuing operations	241,655	(4,903)
Adjustments to reconcile net income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	18,905	18,457
Equity income in joint venture	(462)	(1,462)
Distributions received from joint venture	1,764	3,991
Non-cash compensation expense	1,177	123
Gain on asset sales	(255,947)	
Amortization of deferred finance costs	1,267	1,623
Change in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(4,876)	20,880
Accounts payable and accrued liabilities	(4,917)	(1,991)
Accounts payable and accounts receivable affiliates	(10,279)	2,969
Derivative accounts payable and receivable	15,440	5,868
Net cash provided by continuing operating activities	3,727	45,555
Net cash provided by discontinued operating activities		1,947
Net cash provided by operating activities	3,727	47,502
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital contribution to joint venture	(12,250)	
Capital expenditures	(18,333)	(6,787)
Net proceeds related to asset sales	411,753	
Other	316	336
Net cash provided by (used in) continuing investing activities	381,486	(6,451)
Net cash used in discontinued investing activities	(81)	(1,947)
Net cash provided by (used in) investing activities	381,405	(8,398)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Funds placed in escrow	(293,696)	
Borrowings under credit facility	108,000	137,000
Repayments under credit facility	(178,000)	(183,000)
Repayment of debt		(7,661)
Principal payments on capital lease	(52)	(94)
Net proceeds from issuance of common limited partner units	468	15,332
Net distributions to non-controlling interest holders	(1,224)	(1,678)

Distributions paid to common limited partners, the General Partner and preferred limited partners	(20,554)	
Other	(71)	135
Net cash used in financing activities	(385,129)	(39,966)
Net change in cash and cash equivalents	3	(862)
Cash and cash equivalents, beginning of period	164	1,021
Cash and cash equivalents, end of period	$ 167	$ 159

See accompanying notes to consolidated financial statements

Table of Contents

ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

MARCH 31, 2011

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 Appalachia regions. 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 March 31, 2011, 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., formerly known as Atlas Pipeline Holdings, L.P., a publicly-traded partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At March 31, 2011, the Partnership had 53,494,910 common units outstanding, including 1,641,026 common units held by the General Partner and 4,113,227 common units held by Atlas Energy, L.P. At March 31, 2011, the Partnership also had 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units outstanding.

On February 17, 2011, Atlas Energy, Inc., a formerly publicly-traded company, completed an agreement and plan of merger with Chevron Corporation (Chevron), pursuant to which, among other things, Atlas Energy, Inc. became a wholly-owned subsidiary of Chevron (the Chevron Merger). At the time of the Chevron Merger, Atlas Energy, Inc. owned a 64.3% ownership interest in Atlas Energy, L.P. s common units, and 1,112,000 of the Partnership s common units, along with 8,000 $1,000 par value 12% cumulative Class C preferred limited partner units. The Partnership s common units and 12% cumulative Class C preferred units held directly by Atlas Energy, Inc. were acquired by Chevron as part of the Chevron Merger. Atlas Energy, Inc. contributed Atlas Energy, L.P. s general partner, Atlas Energy GP, LLC (formerly known as Atlas Pipeline Holdings GP, LLC) to Atlas Energy, L.P., so that Atlas Energy GP, LLC became Atlas Energy, L.P. s wholly-owned subsidiary. In addition, Atlas Energy, Inc. distributed to its stockholders all Atlas Energy, L.P. s common units that it held.

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-Q from the amounts previously presented to reflect the following items:

- On September 16, 2010, the Partnership completed the sale of its Elk City and Sweetwater, Oklahoma natural gas gathering systems (collectively Elk City) (see Note 4). The Partnership has retrospectively adjusted its prior period consolidated financial statements to reflect the amounts related to the operations of Elk City as discontinued operations.

- The Partnership reclassified Equity income in joint venture and Gain (loss) on asset sales and other to line items separate from Total revenue and other income (loss) net .

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2010 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, 2010. The results of operations for the three month period ended March 31, 2011 may not necessarily be indicative of the results of operations for the full year ending December 31, 2011.

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, 2010.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds was 8.0% and 7.4% for the three months ended March 31, 2011 and 2010, respectively. The amount of capitalized interest was $0.2 million and $0.1 million for the three months ended March 31, 2011 and 2010, respectively.

Intangible Assets

The Partnership has recorded intangible assets with finite lives in connection with certain consummated acquisitions. The following table reflects the components of intangible assets being amortized at March 31, 2011 and December 31, 2010 (in thousands):

	March 31, 2011	December 31, 2010	Estimated Useful Lives In Years
Customer relationships:			
Gross carrying amount	$ 205,313	$ 205,313	7 10
Accumulated amortization	(84,710)	(78,934)	
Net carrying amount	$ 120,603	$ 126,379	

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 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. Amortization expense on intangible assets was $5.8 million for both of the three months ended March 31, 2011 and 2010. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2011 to 2013 - $23.1 million per year; 2014 - $19.5 million; 2015 - $14.5 million.

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.

Table of Contents

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 that the partnership agreement contractually limits cash distributions to available cash and, 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 12), 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. As such, the net income (loss) utilized in the calculation of net income (loss) per unit must be after 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 March 31, 2011	Three Months Ended March 31, 2010[1]
Continuing operations:		
Net income (loss)	$ 241,655	$ (4,903)
Income attributable to non-controlling interest	(1,187)	(1,317)
Preferred unit dividends	(240)	
Net income (loss) attributable to common limited partners and the General Partner	240,228	(6,220)
Less: net income (loss) attributable to the General Partner s ownership interests	4,829	(119)
Net income (loss) attributable to common limited partners	235,399	(6,101)
Less: net income attributable to participating securities phantom units[2]	2,060	
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	$ 233,339	$ (6,101)
Discontinued operations:		
Net income (loss)	$ (81)	$ 6,781
Less: net income (loss) attributable to the General Partner s ownership interests	(2)	130
Net income (loss) utilized in the calculation of net income (loss) from discontinued operations attributable to common limited partners per unit	$ (79)	$ 6,651

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

(2) Net income attributable to common limited partners ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended March 31, 2010, net loss attributable to common limited partners ownership interest was not allocated to approximately 51,000 phantom units because the contractual terms of the phantom units as participating securities do not

require the holders to share in the losses of the entity.

Table of Contents

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of 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 plan (see Note 12).

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 March 31, 2011	2010[1]
Weighted average number of common limited partners - basic	53,375	52,849
Add effect of participating securities phantom units[1]	471	
Add effect of dilutive option incentive awards[2]		
Weighted average number of common limited partners - diluted	53,846	52,849

(1) For the three months ended March 31, 2010, approximately 51,000 phantom units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such phantom units would have been anti-dilutive.

(2) For the three months ended March 31, 2010, 100,000 unit options were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such unit options would have been anti-dilutive.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources. These changes, other than net income (loss), are referred to as other comprehensive income (loss) or OCI and for the Partnership only include changes in the fair value of unsettled derivative contracts which were previously accounted for as cash flow hedges (see Note 8). The following table sets forth the calculation of the Partnership s comprehensive income (loss) (in thousands):

	Three Months Ended March 31, 2011	2010
Net income	$ 241,574	$ 1,878
Income attributable to non-controlling interests	(1,187)	(1,317)
Preferred unit dividends	(240)	
Net income attributable to common limited partners and the General Partner	240,147	561
Other comprehensive income:		
Adjustment for realized losses on derivatives reclassified to net income	1,702	10,718
Comprehensive income	$ 241,849	$ 11,279

Revenue Recognition

The Partnership s revenue primarily consists of the sale of natural gas and NGLs along with the fees earned from its gathering and processing operations. Under certain agreements, the Partnership purchases natural gas from producers and moves it into receipt points on its pipeline systems, and then sells the natural gas, or produced NGLs if any, off of 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 is recognized upon physical delivery of the natural gas. In connection with the Partnership s gathering and processing operations, it enters into the following types of contractual relationships with its producers and shippers:

Fee-Based Contracts. These contracts provide a set fee for gathering and/or processing raw natural gas. Revenue is a function of the volume of natural gas that the Partnership gathers and processes and is not directly dependent on the value of the natural gas. The Partnership is also paid a separate compression fee on many of its 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.

Percentage of Proceeds (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. The volume of gas gathered or purchased is based on the measured volume at an agreed upon location (generally at the wellhead). The volume of gas redelivered or sold at the tailgate of the Partnership s processing facility will be lower than the volume purchased at the wellhead primarily due to NGLs extracted when processed through a plant. The Partnership must make up or keep the producer whole for this loss in volume. 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 (i) the volume of residue gas available for redelivery to the producer may be less than received from the producer; or (ii) the aggregate proceeds from the sale of the processed natural gas and NGLs could be less than the amount that 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 Keep-Whole agreements is often 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 of margin risk.

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 March 31, 2011 and December 31, 2010 of $61.6 million and $57.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

NOTE 3 INVESTMENT IN JOINT VENTURE

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain Midstream, LLC (Laurel Mountain) a Delaware limited liability company 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 and divested its interests in Atlas Energy, L.P. (see Note 1), resulting in the Laurel Mountain sale being classified as a third party sale. The Partnership recognized a net gain on the sale of assets of $253.7 million, including a $2.2 million loss recognized during the year ended December 31, 2010. 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 10) and for general corporate purposes.

The Partnership recognized its 49% non-controlling ownership interest in Laurel Mountain as an investment in joint venture on its consolidated balance sheets at fair value. The Partnership accounted for its

Table of Contents

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 on its consolidated statements of operations. Since the Partnership accounted for its ownership as an equity investment, the Partnership did not classify the earnings or the gain on sale related to Laurel Mountain as discontinued operations.

The Partnership retained its preferred distribution rights with respect to an $8.5 million note receivable due from Williams, related to the formation of Laurel Mountain in 2009, including interest due on this note. The preferred distribution rights with respect to the note receivable has been reclassified from investment in joint venture to long term notes receivable on the Partnership s consolidated balance sheets. Any amount that remains outstanding on this note after June 1, 2012 will be paid to the Partnership in cash.

NOTE 4 DISCONTINUED OPERATIONS

On September 16, 2010, the Partnership completed the sale of its Elk City and Sweetwater, Oklahoma natural gas gathering systems, and the related processing and treating facilities (including the Prentiss treating facility and the Nine Mile processing plant, collectively, Elk City) to a subsidiary of Enbridge Energy Partners, L.P. (NYSE: EEP) for $682.0 million in cash, excluding working capital adjustments and transaction costs, and recognized a gain of $312.1 million on the sale of Elk City within income from discontinued operations on its consolidated statements of operations, during the year ended December 31, 2010. During the three months ended March 31, 2011, the Partnership recorded, within its consolidated statements of operations, a reduction to the gain on sale of Elk City of $81 thousand to recognize the final settlement of working capital adjustments and transaction costs. The Partnership accounted for the earnings of Elk City as discontinued operations within its consolidated financial statements. Elk City was previously reported within the Partnership s Mid-Continent segment of operations.

The following table summarizes the components included within income from discontinued operations on the Partnership s consolidated statements of operations (in thousands):

	Three Months Ended March 31,	
	2011	**2010**
Total revenue and other income, net	$	$ 41,984
Total costs and expenses		(35,203)
Loss on asset sales and other	(81)	
Income (loss) from discontinued operations	$ (81)	$ 6,781

The Partnership s continuing operations include $0.3 million within natural gas and liquids revenue for the three months ended March 31, 2010, for intercompany sales from the Chaney Dell system to Elk City, which was previously eliminated on the Partnership s consolidated statement of operations. In periods subsequent to the sale of Elk City, these sales have been and will be made directly to third parties.

NOTE 5 CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all of its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership for the period from January 1, 2010 through March 31, 2011 were as follows:

Table of Contents

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, 2010	None	$ 0.00	$	$
June 30, 2010	None	0.00		
September 30, 2010	November 14, 2010	0.35	18,660	363
December 31, 2010	February 14, 2011	0.37	19,735	398

On April 26, 2011, the Partnership declared a cash distribution of $0.40 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended March 31, 2011. The $21.4 million distribution, including $0.4 million to the General Partner for its general partner interest, will be paid on May 13, 2011 to unitholders of record at the close of business on May 6, 2011.

NOTE 6 PROPERTY, PLANT AND EQUIPMENT

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

	March 31, 2011	December 31, 2010	Estimated Useful Lives in Years
Pipelines, processing and compression facilities	$ 1,360,554	$ 1,340,944	2 40
Rights of way	157,276	156,713	20 40
Buildings	8,047	8,047	40
Furniture and equipment	9,271	8,981	3 7
Other	12,975	12,659	3 10
	1,548,123	1,527,344	
Less accumulated depreciation	(199,452)	(186,342)	
	$ 1,348,671	$ 1,341,002	

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 are expensed as incurred. Major renewals and improvements that extend the useful lives of property 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. Depreciation expense on property, plant and equipment was $13.1 million and $12.7 million for the three months ended March 31, 2011 and 2010, respectively. 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.

Leased property and equipment meeting capital lease criteria are capitalized at the original cost of the equipment and are included within property plant and equipment. Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets.

Table of Contents

NOTE 7 OTHER ASSETS

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

	March 31, 2011	December 31, 2010
Deferred finance costs, net of accumulated amortization of $25,703 and $24,436 at March 31, 2011 and December 31, 2010, respectively	$ 25,180	$ 26,227
Security deposits	2,524	2,841
	$ 27,704	$ 29,068

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 10). Total amortization expense of deferred finance costs was $1.3 million and $1.6 million for the three months ended March 31, 2011 and 2010, respectively, which is recorded within interest expense on the Partnership s consolidated statements of operations. Amortization expense related to deferred finance costs is estimated to be as follows for each of the next five calendar years: 2011 - $8.1 million; 2012 to 2014 - $4.0 million per year; 2015 - $3.7 million.

NOTE 8 DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments, principally swaps and options, in connection with its commodity price and interest rate risk management activities. The Partnership enters into financial swap and option instruments to hedge its forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. It also previously entered into financial swap instruments to hedge certain portions of its floating interest rate debt against the variability in market interest rates. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold or interest payments on the underlying debt instrument are due. 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 option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the 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 option agreement sets a floor price for commodity sales being hedged.

The Partnership no longer applies hedge accounting for derivatives. As such, changes in fair value of derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The 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 $5.9 million of the $9.5 million net loss in accumulated other comprehensive loss within Equity on the Partnership s consolidated balance sheets at March 31, 2011, to natural gas and liquids revenue on the Partnership s consolidated statements of operations over the next twelve month period. Aggregate losses of $3.6 million will be reclassified to natural gas and liquids revenue on the Partnership s consolidated statements of operations in later periods.

Derivatives are recorded on the Partnership s consolidated balance sheets as assets or liabilities at fair value. Premium costs 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 other income (loss), net as unrealized gain (loss) on the Partnership s consolidated statements of operations. Premium costs are reclassified to realized gain (loss) within other income (loss), net at the time the option expires or is exercised. The Partnership reflected net derivative liabilities on its consolidated balance sheets of $23.9 million and $10.2 million, at March 31, 2011 and December 31, 2010, respectively.

Table of Contents

The fair value of the Partnership s derivative instruments was included in its consolidated balance sheets as follows (in thousands):

	March 31, 2011	December 31, 2010
Current portion of derivative asset	$ 158	$
Current portion of derivative liability	(16,851)	(4,564)
Long-term derivative liability	(7,217)	(5,608)
	$ (23,910)	$ (10,172)

The following table summarizes the Partnership s gross fair values of commodity-based derivative instruments for the periods indicated (in thousands):

Balance Sheet Location	March 31, 2011	December 31, 2010
Asset Derivatives		
Current portion of derivative asset	$ 796	$
Current portion of derivative liability	3,053	2,624
Long-term derivative liability	2,384	1,052
	6,233	3,676
Liability Derivatives		
Current portion of derivative asset	(638)	
Current portion of derivative liability	(19,904)	(7,188)
Long-term derivative liability	(9,601)	(6,660)
	(30,143)	(13,848)
Total Derivatives	$ (23,910)	$ (10,172)

The following table summarizes the Partnership s commodity derivatives as of March 31, 2011, none of which are designated for hedge accounting (dollars and volumes in thousands):

Fixed Price Swaps

Production Period	Purchased/ Sold	Commodity	Volumes(2)	Average Fixed Price	Fair Value(1) Asset/ (Liability)
Natural Gas					
2011	Sold	Natural Gas Basis	1,440	$ (0.728)	$ (692)
2011	Purchased	Natural Gas Basis	1,440	(0.758)	735
2011	Sold	Natural Gas	3,300	4.637	155
Natural Gas Liquids					
2011	Sold	Ethane	5,040	0.500	(857)
2011	Sold	Propane	12,852	1.153	(3,031)
2011	Sold	Isobutane	1,008	1.618	(164)

2011	Sold	Normal Butane	2,772	1.580		(841)
2011	Sold	Natural Gasoline	6,552	2.042		(2,625)
2012	Sold	Propane	14,868	1.277		(951)
2012	Sold	Natural Gasoline	2,520	2.395		15
Crude Oil						
2011	Sold	Crude Oil	99	91.64		(1,598)
2012	Sold	Crude Oil	84	99.50		(579)
Total Fixed Price Swaps					$	(10,433)

17

Table of Contents

Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes[2]	Average Strike Price	Fair Value[1] Asset/ (Liability)
Natural Gas Liquids						
2011	Purchased	Put	Propane	14,616	$ 1.280	$ 957
2012	Purchased	Put	Propane	3,780	1.359	627
Crude Oil						
2011	Purchased	Put	Crude Oil	402	93.36	1,014
2011	Sold	Call	Crude Oil	509	93.35	(8,789)
2011	Purchased[3]	Call	Crude Oil	189	125.20	523
2012	Purchased	Put	Crude Oil	60	105.00	739
2012	Sold	Call	Crude Oil	498	94.69	(9,691)
2012	Purchased[3]	Call	Crude Oil	180	125.20	1,143
Total Options						$ (13,477)
Total Fair Value						$ (23,910)

(1) See Note 9 for discussion on fair value methodology.
(2) Volumes for natural gas are stated in MMBTU s. Volumes for NGLs are stated in gallons. Volumes for crude oil are stated in barrels.
(3) Calls purchased for 2011 and 2012 represent offsetting positions for calls sold. These offsetting positions were entered into to limit the loss which could be incurred if crude oil prices continued to rise.

During the three months ended March 31, 2010, the Partnership made net payments of $13.4 million related to the early termination of derivative contracts. The terminated derivative contracts were to expire at various times through the fourth quarter of 2010. No contracts were terminated early during the three months ended March 31, 2011.

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

		For the Three Months ended March 31, 2011	2010[1]
Gain (Loss) Reclassified from Accumulated Other Comprehensive Income into Income			
Contract Type	**Location**		
Interest rate contracts[2]	Interest expense	$	$ (1,785)
Commodity contracts[2]	Natural gas and liquids revenue	(1,702)	(4,943)
Commodity contracts[2]	Discontinued operations		(3,990)
		$ (1,702)	$ (10,718)
Gain (Loss) Recognized in Income (Ineffective portion and derivatives not designated as hedges)			
Contract Type	**Location**		
Interest rate contracts[2]	Other income (loss), net	$	$ (6)
Commodity contracts[3]	Other income (loss), net	(21,645)	4,292

Commodity contracts[3]	Discontinued operations		(153)
		$ (21,645)	$ 4,133

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).
(2) Hedges previously designated as cash flow hedges.
(3) Dedesignated cash flow hedges and non-designated hedges.

Table of Contents

NOTE 9 FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative 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 assumption that market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather based upon particular valuation techniques.

The Partnership uses a fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 8). At March 31, 2011, all of the Partnership s derivative contracts are defined as Level 2, with the exception of the Partnership s NGL fixed price swaps and NGL options. 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 price for futures and option contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula. Valuations for the Partnership s NGL fixed price swaps are based on a forward price curve modeled on a regression analysis of quoted price curves for NGL s for similar locations, and therefore are defined as Level 3. 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 following table represents the Partnership s derivative assets and liabilities recorded at fair value as of March 31, 2011 and December 31, 2010 (in thousands):

	Level 1	Level 2	Level 3	Total
March 31, 2011				
Assets				
Commodity swaps	$	$ 1,171	$ 59	$ 1,230
Commodity options		3,419	1,584	5,003
Total assets		4,590	1,643	6,233
Liabilities				
Commodity swaps		(3,150)	(8,513)	(11,663)
Commodity options		(18,480)		(18,480)
Total liabilities		(21,630)	(8,513)	(30,143)
Total derivatives	$	$ (17,040)	$ (6,870)	$ (23,910)

Table of Contents

	Level 1	Level 2	Level 3	Total
December 31, 2010				
Assets				
Commodity swaps	$	$ 1,225	$ 124	$ 1,349
Commodity options		2,327		2,327
Total assets		3,552	124	3,676
Liabilities				
Commodity swaps		(1,461)	(1,914)	(3,375)
Commodity options		(10,473)		(10,473)
Total liabilities		(11,934)	(1,914)	(13,848)
Total derivatives	$	$ (8,382)	$ (1,790)	$ (10,172)

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the three months ended March 31, 2010 (in thousands):

	NGL Fixed Price Swaps		NGL Put Options		Total
	Volume(1)	Amount	Volume(1)	Amount	Amount
Balance December 31, 2010	32,760	$ (1,790)		$	$ (1,790)
New contracts	22,176		18,396		
Cash settlements from unrealized gain (loss)(2)(3)	(9,324)	1,703			1,703
Net change in unrealized gain (loss)(2)		(8,367)		(1,526)	(9,893)
Deferred option premium recognition(3)				3,110	3,110
Balance March 31, 2010	45,612	$ (8,454)	18,396	$ 1,584	$ (6,870)

(1) Volumes for NGLs are stated in gallons.
(2) Included within other income, net on the Partnership s consolidated statements of operations.
(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

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 that 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 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. The estimated fair values of the Partnership s total debt at March 31, 2011 and December 31, 2010, which consists principally of borrowings under the credit facility and the Senior Notes, were $495.1 million and $532.3 million, respectively, compared with the carrying amounts of $496.1 million and $566.0 million, respectively. The Senior Notes were valued based upon available market data for similar issues. The carrying value of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximates their estimated fair value.

NOTE 10 DEBT

Total debt consists of the following (in thousands):

Table of Contents

	March 31, 2010	December 31, 2010
Revolving credit facility	$	$ 70,000
8.125% Senior notes due 2015	272,329	272,181
8.75% Senior notes due 2018	223,050	223,050
Capital lease obligations	691	743
Total debt	496,070	565,974
Less current maturities	(213)	(210)
Total long term debt	$ 495,857	$ 565,764

Cash payments for interest related to debt, net of amounts capitalized, were $0.6 million and $17.9 million for the three months ended March 31, 2011 and 2010, respectively.

Revolving Credit Facility

At March 31, 2011, the Partnership had a $350.0 million senior secured revolving credit facility with a syndicate of banks, which matures in December 2015. Borrowings under the revolving credit facility bear interest, at the Partnership s option, at either (i) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% and (c) three-month LIBOR plus 1.0%, or (ii) the LIBOR rate for the applicable period (each plus the applicable margin). The effective interest rate for borrowings on the revolving credit facility, at March 31, 2011, was 3.0%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $3.2 million was outstanding at March 31, 2011. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership s consolidated balance sheets. At March 31, 2011, the Partnership had $346.8 million of remaining committed capacity under its revolving credit facility.

Borrowings under the revolving credit facility are secured by a lien on and security interest in all of the Partnership s property and that of its subsidiaries, except for the assets owned by Chaney Dell and Midkiff/Benedum joint ventures; and by the guaranty of each of the Partnership s consolidated subsidiaries other than the joint venture companies. The credit facility contains customary covenants, including restrictions on the Partnership s ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to its unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in its subsidiaries. The Partnership is also 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 which 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 March 31, 2011, the Partnership was in compliance with all covenants under the revolving credit facility.

Senior Notes

At March 31, 2011, the Partnership had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). The Partnership s 8.125% Senior Notes are presented combined with a net $3.2 million of unamortized discount as of March 31, 2011. Interest on the Senior Notes in the aggregate 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, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, the Partnership may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by the

Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to the Partnership s secured debt, including the Partnership s obligations under its credit facility.

The Partnership indentures governing the Senior Notes in the aggregate contain covenants, including limitations of the Partnership s ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of its assets. The Partnership is in compliance with these covenants as of March 31, 2011.

On March 7, 2011, the Partnership elected, pursuant to the indenture for the 8.125% Senior Notes, to redeem all of the 8.125% Senior Notes on April 8, 2011. 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 placed $293.7 million in escrow to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. At March 31, 2011, the escrow is recorded on the Partnership s consolidated balance sheets as current assets of $7.0 million and long-term assets of $286.7 million. The redemption of the 8.125% Senior Notes was completed on April 8, 2011 (see Note 16).

On March 8, 2011, the Partnership commenced an offer to purchase, at par, its 8.75% Senior Notes. The Partnership s sale of its 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 (see Note 3). As a result of the Asset Sale, the Partnership offered to purchase any and all of the 8.75% Senior Notes. The offer expired on April 7, 2011. The Partnership redeemed $7.2 million of the 8.75% Senior Notes (see Note 16).

NOTE 11 COMMITMENTS AND CONTINGENCIES

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

On February 26, 2010, the Partnership received notice from Williams, its former joint venture partner in Laurel Mountain, alleging that certain title defects exist with respect to the real property contributed by the Partnership to Laurel Mountain. Under the Formation and Exchange Agreement with Williams (Formation Agreement): (i) Williams had nine months after closing (the Claim Date) to assert any alleged title defects, and (ii) the Partnership had 30 days following the Claim Date to contest the title defects asserted by Williams and 180 days following the Claim Date to cure those title defects, which was extended by agreement until March 31, 2011. On March 26, 2010, the Partnership delivered notice, disputing Williams alleged title defects as well as the amounts claimed. The Partnership has delivered documentation to Williams, which should resolve many of the alleged title defects. Although the Partnership s cure period has technically expired, the Partnership, without objection from Williams, continues work to resolve the remaining alleged title defects. In addition, Atlas Energy, Inc. delivered a proposed assignment to Laurel Mountain that should resolve some of the alleged deficiencies. Williams also claims, in a letter dated August 26, 2010, that the alleged title defects violate the Partnership s representation with respect to sufficiency of the assets contributed to Laurel Mountain. If valid, this would make Williams title defect claims subject to a higher deductible (which is noted below). The Partnership believes its representations with respect to title are Williams sole and exclusive remedy with respect to title matters.

In August 2010, Williams asserted additional indemnity claims under the Formation Agreement totaling approximately $19.8 million. Williams claims are generally based on the Partnership s alleged failure to construct and maintain the assets contributed to Laurel Mountain in accordance with standard industry practice or applicable law. As a preliminary matter, the Partnership believes Williams has overstated its claim by forty-nine percent (49%), because, under the Formation Agreement, these claims are reduced on a pro-rata basis to equal Williams percentage ownership interest in Laurel Mountain. The Partnership has received some additional information from Williams and, based on the Partnership s analysis of that information, believes that an adverse outcome is probable with respect to some portion of Williams claims.

The Partnership has established an accrual with respect to the portion of Williams claims that it deems probable, which is less than 51% of the amounts asserted by Williams. Under the Formation Agreement, Williams indemnity claims are capped, in the aggregate, at $27.5 million. In addition, the Partnership is entitled to indemnification from Atlas Energy, Inc. with respect to some of Williams claims.

NOTE 12 BENEFIT PLANS

Generally, all share-based payments to employees, including grants of unit options and phantom units, which are not cash settled, are recognized in the financial statements based on their fair values on the date of the grant.

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.

Partnership s Long-Term Incentive Plans

The Partnership has a 2004 Long-Term Incentive Plan (2004 LTIP) and a 2010 Long-Term Incentive Plan, which was modified on April 26, 2011, (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 March 31, 2011, the Partnership had 414,716 phantom units outstanding under the Partnership s LTIPs, with 2,495,617 phantom units and unit options available for grant.

Partnership Phantom Units. Through March 31, 2011, 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 will automatically vest upon a change of control, as defined in the LTIPs. At March 31, 2011, there were 159,483 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 1) and 75,250 outstanding phantom units, which represents all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at March 31, 2011 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were $0.2 million for the three months ended March 31, 2011. These amounts were recorded as reductions of Equity on the Partnership s consolidated balance sheets. No LTIP DERs were paid for the three months ended March 31, 2010.

Table of Contents

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

	Three Months Ended March 31 2011		2010	
	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
Outstanding, beginning of period	490,886	$ 11.75	52,233	$ 39.72
Granted	5,730	30.63	1,000	12.70
Matured(2)	(81,900)	13.60	(2,695)	42.78
Forfeited			(1,375)	43.99
Outstanding, end of period(3)	414,716	$ 11.65	49,163	$ 38.88
Non-cash compensation expense recognized (in thousands)(4)		$ 1,174		$ 122

(1) Fair value based upon weighted average grant date price, which is utilized in the calculation of compensation expense.
(2) The intrinsic values for phantom unit awards exercised during the three months ended March 31, 2011 and 2010 were $2.4 million and $0.04 million, respectively.
(3) The aggregate intrinsic value for phantom unit awards outstanding at March 31, 2011 and 2010 was $14.3 million and $0.7 million, respectively.
(4) Incremental compensation expense of $472 thousand, related to the accelerated vesting of phantom units held by the CEO of the General Partner, was recognized during the three months ended March 31, 2011.

At March 31, 2011, the Partnership had approximately $2.2 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 1.8 years.

Partnership Unit Options. At March 31, 2011, 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 1) and 50,000 outstanding unit options held by the CEO automatically vested. As of March 31, 2011, all unit options were exercised.

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

	Three Months Ended March 31, 2011		2010	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	75,000	$ 6.24	100,000	$ 6.24
Exercised(1)	(75,000)	6.24		
Outstanding, end of period(2)		$	100,000	$ 6.24
Options exercisable, end of period		$	25,000	$ 6.24
Non-cash compensation expense recognized (in thousands)(3)		$ 3		$ 1

(1) The intrinsic value for unit option awards exercised during the three months ended March 31, 2011 was $1.8 million. Approximately $0.5 million was received from exercise of unit option awards during the three months ended March 31, 2011.
(2) The aggregate intrinsic value of options outstanding at March 31, 2010 was $0.8 million.
(3) Incremental compensation expense of $2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner, was recognized during the three months ended March 31, 2011.

NOTE 13 RELATED PARTY TRANSACTIONS

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of Atlas Energy, L.P. The General Partner does not receive a management fee in connection with its management of the Partnership apart from its interest as general partner and its right to receive incentive distributions. The Partnership reimburses the General Partner and its affiliates for compensation and benefits related to its employees who perform services for the Partnership

Table of Contents

based upon an estimate of the time spent by such persons on activities for the Partnership. Other indirect costs, such as rent for offices, are allocated to the Partnership by Atlas Energy, L.P. based on the number of its employees who devote their time to activities on the Partnership s behalf.

The partnership agreement provides that the General Partner will determine the costs and expenses that are allocable to the Partnership in any reasonable manner determined by the General Partner at its sole discretion. These costs and expenses are limited to $1.8 million for the twelve months following the closing of the Chevron Merger. The Partnership reimbursed the General Partner and its affiliates $0.4 million for both the three months ended March 31, 2011 and 2010 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 three months ended March 31, 2011 and 2010. The General Partner believes that 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 14 SEGMENT INFORMATION

The Partnership has two reportable segments. These reportable segments reflect the way the Partnership manages its operations.

The Mid-Continent segment consists of the Chaney Dell, Velma and Midkiff/Benedum operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins. Mid-Continent revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

The Appalachia segment is comprised of natural gas transportation, gathering and processing assets located in Tennessee. Appalachia revenues are based on contractual arrangements with Atlas Energy, L.P. and its affiliates, as well as third parties. The Appalachia segment includes the revenues and gain on sale related to the Partnership s 49% interest in Laurel Mountain, which it sold on February 17, 2011 (see Note 3).

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

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Three Months Ended March 31, 2011:				
Revenue:				
Revenues third party[1]	$ 369	$ 279,719	$ (23,347)	$ 256,741
Revenues affiliates	122			122
Total revenue and other income (loss), net	491	279,719	(23,347)	256,863
Costs and Expenses:				
Operating costs and expenses	184	231,066		231,250
General and administrative[1] `			9,017	9,017
Depreciation and amortization	142	18,763		18,905
Interest expense[1]			12,445	12,445
Total costs and expenses	326	249,829	21,462	271,617
Equity income	462			462
Gain on asset sales and other	255,947			255,947
Net income (loss) from continuing operation	256,574	29,890	(44,809)	241,655
Loss from discontinued operations			(81)	(81)
Net income (loss)	$ 256,574	$ 29,890	$ (44,890)	$ 241,574

Table of Contents

	Appalachia	Mid-Continent	Corporate and Other	Consolidated
Three Months Ended March 31, 2010[2]:				
Revenue:				
Revenues third party[1]	$ 24	$ 240,610	$ (657)	$ 239,977
Revenues affiliates	176			176
Total revenue and other income (loss), net	200	240,610	(657)	240,153
Costs and expenses:				
Operating costs and expenses	189	191,718		191,907
General and administrative[1]			9,751	9,751
Depreciation and amortization	151	18,306		18,457
Interest expense[1]			26,403	26,403
Total costs and expenses	340	210,024	36,154	246,518
Equity income	1,462			1,462
Net income (loss) from continuing operation	1,322	30,586	(36,811)	(4,903)
Income from discontinued operations			6,781	6,781
Net income (loss)	$ 1,322	$ 30,586	$ (30,030)	$ 1,878

Capital Expenditures:	Three Months Ended March 31, 2011	2010[2]
Mid-Continent	$ 18,238	$ 7,677
Appalachia	95	
	$ 18,333	$ 7,677

Balance Sheet	March 31, 2011	December 31, 2010
Total assets:		
Mid-Continent	$ 1,580,995	$ 1,574,635
Appalachia	19,095	163,858
Corporate other	319,162	26,355
	$ 1,919,252	$ 1,764,848

The following tables summarize the Partnership s natural gas and liquids revenues by product for the periods indicated (in thousands):

	Three Months Ended March 31, 2011	2010[2]
Natural gas and liquids:		
Natural gas	$ 81,844	$ 85,383
NGLs	167,794	130,901
Condensate	15,557	7,232
Other	1,114	(178)

Total natural gas and liquids	$ 266,309	$ 223,338

(1) The Partnership notes that derivative contracts, 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.
(2) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

NOTE 15 SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION

The Partnership s revolving credit facility is guaranteed by its subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership s consolidated financial statements as of March 31, 2011 and December 31, 2010 and for the three months ended March 31, 2011 and 2010 include the financial statements of Atlas Pipeline Mid-Continent WestOk, LLC (Chaney Dell LLC) and Atlas Pipeline Mid-Continent WestTex,

Table of Contents

LLC (Midkiff/Benedum LLC), entities in which the Partnership has 95% interests. Under the terms of the revolving credit facility, Chaney Dell LLC and Midkiff/Benedum LLC are non-guarantor subsidiaries. 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 March 31, 2011 and December 31, 2010 and for the three months ended March 31, 2011 and 2010. 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

March 31, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 167	$	$	$ 167
Accounts receivable affiliates	35,219			(35,219)	
Other current assets	7,718	25,130	94,089		126,937
Total current assets	42,937	25,297	94,089	(35,219)	127,104
Property, plant and equipment, net		244,479	1,104,192		1,348,671
Intangible assets, net			120,603		120,603
Notes receivable		8,500	1,852,928	(1,852,928)	8,500
Equity investments	1,417,840	(826,448)		(591,392)	
Other assets, net	311,977	1,775	622		314,374
	$ 1,772,754	$ (546,397)	$ 3,172,434	$ (2,479,539)	$ 1,919,252
Liabilities and Equity					
Accounts payable affiliates	$	$ (142,634)	$ 179,854	$ (35,219)	$ 2,001
Current portion of derivative liability		16,851			16,851
Other current liabilities	12,585	26,545	93,247		132,377
Total current liabilities	12,585	(99,238)	273,101	(35,219)	151,229
Long-term derivative liability		7,217			7,217
Long-term debt, less current portion	495,379		478		495,857
Other long-term liability		159			159
Equity	1,264,790	(454,535)	2,898,855	(2,444,320)	1,264,790
	$ 1,772,754	$ (546,397)	$ 3,172,434	$ (2,479,539)	$ 1,919,252

December 31, 2010	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 164	$	$	$ 164
Accounts receivable affiliates	1,329,448			(1,329,448)	
Other current asset	202	25,488	89,187		114,877
Total current assets	1,329,650	25,652	89,187	(1,329,448)	115,041
Property, plant and equipment, net		243,092	1,097,910		1,341,002
Intangible assets, net			126,379		126,379
Investment in joint venture		153,358			153,358
Notes receivable			1,852,928	(1,852,928)	

Equity investments	252,725	(633,455)		380,730	
Other assets, net	26,605	1,775	688		29,068
	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848
Liabilities and Equity					
Accounts payable affiliates	$	$ 1,173,729	$ 167,999	$ (1,329,448)	$ 12,280
Current portion of derivative liability		4,564			4,564
Other current liabilities	2,102	47,162	85,498		134,762
Total current liabilities	2,102	1,225,455	253,497	(1,329,448)	151,606
Long-term derivative liability		5,608			5,608
Long-term debt, less current portion	565,231		533		565,764
Other long-term liability		223			223
Equity	1,041,647	(1,440,864)	2,913,062	(1,472,198)	1,041,647
	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848

Table of Contents

Statements of Operations

Three Months Ended March 31, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Total revenue and other income (loss), net	$	$ 33,045	$ 223,818	$	$ 256,863
Total costs and expenses	(11,095)	(64,903)	(195,619)		(271,617)
Equity income	251,672	28,148		(279,358)	462
Gain on asset sales and other		255,947			255,947
Income (loss) from continuing operations	240,577	252,237	28,199	(279,358)	241,655
Loss from discontinued operations		(81)			(81)
Net income (loss)	$ 240,577	$ 252,156	$ 28,199	$ (279,358)	$ 241,574
Three Months Ended March 31, 2010[(1)]					
Total revenue and other income (loss), net	$	$ 46,242	$ 193,911	$	$ 240,153
Total costs and expenses	(26,659)	(56,263)	(163,596)		(246,518)
Equity income in subsidiaries	27,319	31,228		(57,085)	1,462
Income (loss) from continuing operations	660	21,207	30,315	(57,085)	(4,903)
Income from discontinued operations		6,781			6,781
Net income (loss)	$ 660	$ 27,988	$ 30,315	$ (57,085)	$ 1,878

Statements of Cash Flows

Three Months Ended March 31, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Net cash provided by (used in):					
Total operating activities	$ 74,908	$ (5,551)	$ 45,901	$ (111,531)	$ 3,727
Continuing investing activities	310,169	589,527	(15,298)	(502,912)	381,486
Discontinued investing activities		(81)			(81)
Total investing activities	310,169	589,446	(15,298)	(502,912)	381,405
Total financing activities	(385,077)	(583,892)	(30,603)	614,443	(385,129)
Net change in cash and cash equivalents		3			3
Cash and cash equivalents, beginning of period		164			164
Cash and cash equivalents, end of period	$	$ 167	$	$	$ 167
Three Months Ended March 31, 2010[(1)]					
Net cash provided by (used in):					
Continuing operating activities	$ 10,987	$ 8,529	$ 67,555	$ (41,516)	$ 45,555
Discontinued operating activities		1,947			1,947

Total operating activities	10,987	10,476	67,555	(41,516)	47,502
Continuing investing activities	28,885	151,706	(6,470)	(180,572)	(6,451)
Discontinued investing activities		(1,947)			(1,947)
Total investing activities	28,885	149,759	(6,470)	(180,572)	(8,398)
Total financing activities	(39,872)	(161,097)	(61,085)	222,088	(39,966)
Net change in cash and cash equivalents		(862)			(862)
Cash and cash equivalents, beginning of period		1,021			1,021
Cash and cash equivalents, end of period	$	$ 159	$	$	$ 159

(1) Restated to reflect amounts reclassified to discontinued operations due to the sale of Elk City (see Note 4).

Table of Contents

NOTE 16 SUBSEQUENT EVENTS

On April 7, 2011, the Partnership s offer to purchase its 8.75% Senior Notes expired (see Note 10). The Partnership purchased $7.2 million, or 3.24%, of the outstanding 8.75% Senior Notes, which represented all of the 8.75% Senior Notes validly tendered pursuant to the offer and paid $0.2 million in accrued and unpaid interest for a total payment of $7.4 million. The Partnership funded the purchase with a portion of the net proceeds from the Partnership s sale of its 49% non-controlling interest in Laurel Mountain (see Note 3).

On April 8, 2011, the Partnership completed the redemption of all of its 8.125% Senior Notes for a total redemption of $293.7 million, including accrued interest of $7.0 million and premium of $11.2 million (see Note 10). The redemption was funded with a portion of the net proceeds from the Partnership s sale of its 49% non-controlling interest in Laurel Mountain (see Note 3).

On April 26, 2011, the Partnership signed an agreement to partner with Chevron Pipeline Company, an affiliate of Chevron, through a purchase of a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) from Buckeye Partners, L.P. for $85 million. WTLPG owns a 2,295 mile common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu for fractionation. Chevron Pipeline Company, which owns the remaining 80% interest, is the operator of WTLPG. The transaction is expected to close in the second quarter of 2011, subject to customary closing conditions.

On April 28, 2011, Atlas Energy, L.P., the owner of the Partnership s General Partner, changed the ticker symbol of its common units on the New York Stock Exchange from AHD to ATLS , the former ticker symbol of Atlas Energy, Inc.

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, 2010. 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.

Overview

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

We conduct our business in the midstream segment of the natural gas industry through two reportable segments: Mid-Continent and Appalachia.

Our Mid-Continent operations, as of March 31, 2011, own, have interests in and operate five natural gas processing plants with aggregate capacity of approximately 520 MMCFD. These facilities are connected to approximately 8,600 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas, which gather gas from wells and central delivery points and deliver to our natural gas processing and treating plants, as well as third-party pipelines.

Our Appalachia operations are comprised of natural gas transportation, gathering and processing assets located in Tennessee. Appalachia revenues are based on contractual arrangements with Atlas Energy, L.P. and its affiliates, as well as third parties.

Recent Events

On February 17, 2011, we completed the sale to Atlas Energy Resources, LLC of our 49% non-controlling interest in Laurel Mountain Midstream, LLC (Laurel Mountain), a Delaware limited liability company for $409.5 million in cash, net of expenses and including adjustments based on certain capital contributions we made to and distributions we received from Laurel Mountain after January 1, 2011. We retained the preferred distribution rights under the limited liability company agreement of Laurel Mountain entitling APL Laurel Mountain, LLC, our wholly-owned subsidiary, to receive all payments made under a note issued to Laurel Mountain by Williams Laurel Mountain, LLC in connection with the formation of Laurel Mountain. We intend to utilize the proceeds from the sale to repay our indebtedness, to fund future capital expenditures, and for general corporate purposes.

Table of Contents

Subsequent Events

On April 7, 2011, our offer to purchase our 8.75% Senior Notes expired (see Senior Notes). We purchased $7.2 million, or 3.24%, of the outstanding 8.75% Senior Notes, which represented all of the 8.75% Senior Notes validly tendered pursuant to the offer and paid $0.2 million in accrued and unpaid interest for a total payment of $7.4 million. We funded the purchase from a portion of the net proceeds from the sale of our 49% non-controlling interest in Laurel Mountain (see Recent Events).

On April 8, 2011, we completed the redemption of all of our 8.125% Senior Notes for a total redemption of $293.7 million, including accrued interest of $7.0 million and premium of $11.2 million (see Senior Notes). The redemption was funded with a portion of the net proceeds from the sale of our 49% non-controlling interest in Laurel Mountain (see Recent Events).

On April 26, 2011, we signed an agreement to partner with Chevron Pipeline Company, an affiliate of Chevron Corporation (NYSE: CVX), through a purchase of a 20% interest in West Texas LPG Pipeline Limited Partnership (WTLPG) from Buckeye Partners, L.P. for $85 million. WTLPG owns a 2,295 mile common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu for fractionation. Chevron Pipeline Company, which owns the remaining 80% interest, is the operator of WTLPG. The transaction is expected to close in the second quarter of 2011, subject to customary closing conditions.

On April 28, 2011, Atlas Energy, L.P., the owner of our General Partner, changed the ticker symbol of its common units on the New York Stock Exchange from AHD to ATLS , the former ticker symbol of Atlas Energy, Inc.

Contractual Revenue Arrangements

Our principal revenue is generated from the gathering and sale of natural gas, NGLs and condensate. Variables that affect our revenue 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 that is 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 of 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. Revenue associated with the physical sale of natural gas is recognized upon physical delivery of the natural gas (See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Revenue Recognition for further discussion of contractual revenue arrangements).

Table of Contents

In our Appalachia segment, we gather natural gas for Atlas Energy, L.P. and third-party operators generally under fixed-fee contracts.

Recent Trends and Uncertainties

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

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

As a result of our POP and Keep-Whole contracts, our results of operations and financial condition substantially depend upon the price of natural gas, NGLs and crude oil (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 2 Revenue Recognition). We believe that future natural gas prices will be influenced by supply deliverability, the severity of winter and summer weather and the level of United States economic growth. Based on historical trends, we generally expect NGL prices to follow changes in crude oil prices over the long term, which we believe will in large part be determined by the level of production from major crude oil exporting countries and the demand generated by growth in the world economy. However, energy market uncertainty and volatility has negatively impacted North American drilling activity in the recent past. Lower drilling levels and shut-in wells over a sustained period would have a negative effect on natural gas volumes gathered and processed.

We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. We closely monitor the risks associated with commodity price changes on our future operations and, where appropriate, use various commodity-based derivative instruments such as natural gas, crude oil and NGL contracts to hedge a portion of the value of our assets and operations from such price risks. See Item 3. Quantitative and Qualitative Disclosures About Market Risk Commodity Price Risk for further discussion of commodity price risk.

Currently, there is a significant level of uncertainty in the financial markets. This uncertainty presents additional potential risks to us. These risks include the availability and costs associated with our borrowing capabilities and ability to raise additional capital, and an increase in the volatility of the price of our common units. While we have no definitive plans to access the capital markets, should we decide to do so in the near future, the terms, size, and cost of new debt or equity could be less favorable than in previous transactions.

Table of Contents

Results of Operations

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

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Percent Change
Pricing:			
Mid-Continent Weighted Average Prices:			
NGL price per gallon Conway hub	$ 1.08	$ 1.01	6.9%
NGL price per gallon Mt. Belvieu hub	1.21	1.11	9.0%
Natural gas sales ($/Mcf):			
Velma	3.98	5.19	(23.3)%
Chaney Dell	3.94	5.19	(24.1)%
Midkiff/Benedum	3.92	5.15	(23.9)%
Weighted Average	3.94	5.16	(23.6)%
NGL sales ($/gallon):			
Velma	1.03	1.00	3.0%
Chaney Dell	1.06	1.02	3.9%
Midkiff/Benedum	1.18	1.10	7.3%
Weighted Average	1.10	1.05	4.8%
Condensate sales ($/barrel):			
Velma	92.24	77.19	19.5%
Chaney Dell	84.72	74.57	13.6%
Midkiff/Benedum	89.80	75.53	18.9%
Weighted Average	88.29	75.57	16.8%
Operating data:			
Appalachia:			
Tennessee system:			
Average throughput volumes (MCFD)	8,079	9,001	(10.2)%
Mid-Continent:			
Velma system:			
Gathered gas volume (MCFD)	90,614	73,220	23.8%
Processed gas volume (MCFD)	85,158	70,742	20.4%
Residue Gas volume (MCFD)	69,714	55,482	25.7%
NGL volume (BPD)	10,071	7,760	29.8%
Condensate volume (BPD)	530	477	11.1%
Chaney Dell system:			
Gathered gas volume (MCFD)	242,965	222,004	9.4%
Processed gas volume (MCFD)	228,865	206,912	10.6%
Residue Gas volume (MCFD)	198,640	188,232	5.5%
NGL volume (BPD)	13,591	12,580	8.0%
Condensate volume (BPD)	859	759	13.2%
Midkiff/Benedum system[(1)]:			
Gathered gas volume (MCFD)	185,918	157,693	17.9%
Processed gas volume (MCFD)	172,817	149,084	15.9%
Residue Gas volume (MCFD)	115,917	99,640	16.3%
NGL volume (BPD)	27,476	24,387	12.7%
Condensate volume (BPD)	1,024	690	48.4%

(1) Operating data for the Midkiff/Benedum system represents 100% of its operating activity.

Table of Contents

Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

Revenue. The following table details the revenue changes between the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,			
	2011	**2010[(1)]**	**Change**	**Percent Change**
Revenues:				
Natural gas and liquids	$ 266,309	$ 223,338	$ 42,971	19.2%
Transportation, compression and other fee revenue	9,410	10,095	(685)	(6.8)%
Other income (loss), net	(18,856)	6,720	(25,576)	(380.6)%
Total Revenues	$ 256,863	$ 240,153	$ 16,710	7.0%

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the Elk City system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 4).

Natural gas and liquids revenue for the three months ended March 31, 2011 increased primarily due to a favorable price change as a result of higher realized commodity prices combined with higher production volumes across all systems.

Volumes on the Velma system increased for the three months ended March 31, 2011 when compared to the prior year period primarily due to new production gathered on the Madill-to-Velma gas gathering pipeline. Midkiff/Benedum system volumes for the three months ended March 31, 2011 increased when compared to the prior year period due to increased volumes from Pioneer Natural Resources (NYSE: PXD) (Pioneer) as a result of their continued drilling program. NGL production volume on the Chaney Dell system increased for the three months ended March 31, 2011 compared to the prior year due to the completion of an expansion into Kansas in June 2010.

Other income (loss), net, including the impact of certain gains and losses recognized on derivatives had an unfavorable variance for the three months ended March 31, 2011 due primarily to a $31.5 million unfavorable variance in non-cash mark-to-market adjustments on commodity-based derivatives. 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.

Costs and Expenses. The following table details the costs and expenses changes between the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31,			
	2011	**2010[(1)]**	**Change**	**Percent Change**
Costs and Expenses:				
Natural gas and liquids	$ 218,292	$ 179,759	$ 38,533	21.4%
Plant operating	12,774	11,959	815	6.8%
Transportation and compression	184	189	(5)	(2.6)%
General and administrative	9,017	9,751	(734)	(7.5)%
Depreciation and amortization	18,905	18,457	448	2.4%
Interest expense	12,445	26,403	(13,958)	(52.9)%
Total Costs and Expenses	$ 271,617	$ 246,518	$ 25,099	10.2%

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the Elk City system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 4).

Table of Contents

Natural gas and liquids cost of goods sold for the three months ended March 31, 2011 increased primarily due to an increase in average commodity prices and processed volumes in comparison to the prior year period, as discussed above in revenues.

Interest expense for the three months ended March 31, 2011 decreased primarily due to a $7.2 million decrease in interest expense associated with our term loan, a $4.8 million decrease in interest expense associated with our revolving credit facility and a $1.8 million decrease in interest rate swap expense due to the interest rate swaps expiring in April 2010. The lower interest expense on our term loan and revolving credit facility is primarily due to the retirement of the term loan and a reduction of the credit facility in September 2010 with proceeds from the sale of Elk City.

Other income items. The following table details the changes between the three months ended March 31, 2011 and 2010 for other income items (in thousands):

	Three Months Ended March 31,			
	2011	**2010**(1)	**Change**	**Percent Change**
Equity income in joint venture	$ 462	$ 1,462	$ (1,000)	(68.4)%
Gain on asset sales and other	255,947		255,947	100.0%
Income (loss) from discontinued operations	(81)	6,781	(6,862)	(101.2)%
Income attributable to non-controlling interests	(1,187)	(1,317)	130	9.9%

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the Elk City system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 4).

Equity income represents our ownership interest in the net income of Laurel Mountain, which we sold on February 17, 2011.

Gain on asset sales and other for the three months ended March 31, 2011 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011 (See Recent Events).

Income from discontinued operations, which consists of amounts associated with the Elk City system, decreased $6.9 million from the prior year period due to its sale in September 2010.

Liquidity and Capital Resources

General

Our primary sources of liquidity are cash generated from operations and borrowings under our credit facility. Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our 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 March 31, 2011, we had no outstanding borrowings under our $350.0 million senior secured credit facility and $3.2 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with $346.8 million of remaining committed capacity under the credit facility, (see Revolving Credit Facility). We were in compliance with the credit facility s covenants at March 31, 2011. At March 31, 2011, we had a working capital deficit of $24.1 million compared with a $36.6 million working capital deficit at December 31, 2010. We believe that 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 flow. 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 flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to the extent required and on acceptable terms.

Cash Flows Three Months Ended March 31, 2011 Compared to Three Months Ended March 31, 2010

The following table details the cash flow changes between the three months ended March 31, 2011 and 2010 (in thousands):

	Three Months Ended March 31, 2011	Three Months Ended March 31, 2010	Change	Percent Change
Net cash provided by (used in):				
Operating activities	$ 3,727	$ 47,502	$ (43,775)	(92.2)%
Investing activities	381,405	(8,398)	389,803	4,641.6%
Financing activities	(385,129)	(39,966)	(345,163)	(863.6)%
Net change in cash and cash equivalents	$ 3	$ (862)	$ 865	100.3%

Net cash provided by operating activities for the three months ended March 31, 2011 decreased primarily due to a $41.9 million decrease in the change in working capital and a $1.9 million decrease in cash provided by discontinued operations. The decrease in the change in working capital is primarily due to a $15.1 million increase in receivables and prepaid expenses during the three months ended March 31, 2011 compared to a $23.8 million decrease in receivables and prepaid expenses in the prior year period.

Net cash provided by investing activities for the three months ended March 31, 2011 increased as a result of the net proceeds of $411.8 million received from the sale of our 49% interest in Laurel Mountain, partially offset by a $12.2 million capital contribution to Laurel Mountain and an $11.5 million increase in capital expenditures compared to the prior year period (see further discussion of capital expenditures under Capital Requirements).

Net cash used in financing activities for the three months ended March 31, 2011 increased mainly due to $293.7 million placed in escrow for the repayment of the 8.125% Senior Notes (see Recent Events), combined with a $24.0 million net increase in repayments on our revolving credit facility and a $20.3 million increase in distributions paid. The funds placed in escrow and the increase in repayments on our revolving credit facility is principally due to the retirement of debt with proceeds from the sale of Laurel Mountain (see Recent Events).

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 March 31, 2011	Three Months Ended March 31, 2010(1)
Maintenance capital expenditures	$ 3,260	$ 875
Expansion capital expenditures	15,073	6,802
Total	$ 18,333	$ 7,677

(1) Restated to reflect amounts reclassified to discontinued operations due to our sale of the Elk City system (see Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 4).

Expansion capital expenditures increased for the three months ended March 31, 2011 primarily due to compressor upgrades and pipeline projects. The increase in maintenance capital expenditures for the three months ended March 31, 2011 when compared with the prior year period was due to fluctuations in the timing of scheduled maintenance activity. As of March 31, 2011, we have approved expenditures of approximately $104.4 million on pipeline extensions, compressor station upgrades and processing facility upgrades. After March 31, 2011, we approved additional growth capital expenditures of over $300.0 million, including the purchase of WTLPG from Buckeye Partners L.P. for $85 million (see Subsequent Events) and a 200 Mmcfd expansion of the Chaney Dell System, among other projects. We expect to fund the initial phases of these expansion projects utilizing 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 of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

Our General Partner is granted discretion by our partnership agreement to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures 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

Table of Contents

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 of 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. No incentive distributions were declared for the three months ended March 31, 2011 and 2010.

Off Balance Sheet Arrangements

As of March 31, 2011, our off balance sheet arrangements are limited to our letters of credit, issued under the provisions of our revolving credit facility, totaling $3.2 million. These are in place to support various performance obligations as required by (i) statutes within the regulatory jurisdictions where we operate, (ii) surety and (iii) counterparty support.

Revolving Credit Facility

At March 31, 2011, we had a $350.0 million senior secured revolving credit facility with a syndicate of banks, which matures in December 2015. Borrowings under the revolving credit facility bear interest, at our option, at either (i) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (ii) the LIBOR rate for the applicable period (each plus the applicable margin). The effective interest rate for borrowings on the revolving credit facility, at March 31, 2011, was 3.0%. Up to $50.0 million of the revolving credit facility may be utilized for letters of credit, of which $3.2 million was outstanding at March 31, 2011. 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 of our property and that of our subsidiaries, except for the assets owned by the Chaney Dell and Midkiff/Benedum 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 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 which 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 March 31, 2011, we were in compliance with all covenants under the revolving credit facility.

Senior Notes

At March 31, 2011, we had $223.1 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (8.75% Senior Notes) and $275.5 million principal amount outstanding of 8.125% senior unsecured notes due on December 15, 2015 (8.125% Senior Notes ; collectively, the Senior Notes). Our 8.125% Senior Notes are presented combined with a net $3.2 million of unamortized discount as of March 31, 2011. Interest on the Senior Notes in the aggregate 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, and the 8.125% Senior Notes are redeemable at any time after December 31, 2010, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. Prior to June 15, 2011, we may redeem up to 35% of the aggregate principal amount of the 8.75% Senior Notes with the proceeds of certain equity offerings at a stated redemption price. The Senior Notes in the aggregate are also subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The Senior Notes are junior in right of payment to our secured debt, including our obligations under our credit facility.

On March 7, 2011, we elected, pursuant to the indenture for the 8.125% Senior Notes, to redeem all of the 8.125% Senior Notes on April 8, 2011. 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 placed $293.7 million in escrow to redeem the $275.5 million principal plus $11.2 million premium and $7.0 million accrued interest. The redemption of the 8.125% Senior Notes was completed on April 8, 2011 (see Subsequent Events).

On March 8, 2011, we commenced an offer to purchase, at par, our 8.75% Senior Notes. 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 (see Recent Events). As a result of the Asset Sale, we offered to purchase any and all of the 8.75% Senior Notes. The offer expired on April 7, 2011, and we purchased $7.2 million of the 8.75% Senior Notes (see Subsequent Events).

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 of our assets. We are in compliance with these covenants as of March 31, 2011.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depreciation and amortization, asset impairment, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. A discussion of our significant accounting policies we have adopted and followed in the preparation of our consolidated financial statements is included within our Annual Report on Form 10-K for the year ended December 31, 2010, and there have been no material changes to these policies through March 31, 2011.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

Table of Contents

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 March 31, 2011. 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 currently participating in our revolving credit facility. We may choose to do business with counterparties outside of our credit facility in the future. 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 March 31, 2011, we had a $350.0 million senior secured revolving credit facility with no outstanding borrowings. Borrowings under the revolving credit facility bear interest, at our option, at either (i) the higher of (a) the prime rate, (b) the federal funds rate plus 0.50% or (c) three-month LIBOR plus 1.0%, or (ii) the LIBOR rate for the applicable period (each plus the applicable margin). The effective interest rate for the revolving credit facility borrowings was 3.0% at March 31, 2011. At March 31, 2011, we had no interest rate derivative contracts. Assuming that we borrowed the full $350.0 million available 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 $3.5 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 or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right, but not the obligation, to receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. See Item 1. Notes to Consolidated Financial Statements (Unaudited) Note 8 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 April 7, 2011, are $1.30 per gallon, $4.46 per million BTU and $111.23 per barrel. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended March 31, 2012 by approximately $11.2 million.

ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our General Partner s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management 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.

Table of Contents

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 March 31, 2011, our disclosure controls and procedures were effective at the reasonable assurance level.

There have been no changes in our internal control over financial reporting during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Following the November 9, 2010 announcement that Atlas Energy, Inc. had entered into a definitive agreement to be acquired by Chevron Corporation and that we agreed to enter into a separate transaction with Atlas Energy, Inc. relating to our interest in Laurel Mountain, a purported shareholder derivative case was filed on November 16, 2010, in the Western District of Pennsylvania federal court, Ussach v. ATLS, et al., C.A. No. 2:10-cv-1533. The complaint is asserted derivatively on behalf of us and names Atlas Energy, Inc., the General Partner, and members of the Managing Board of the General Partner as defendants (Defendants) and alleges that Defendants have violated their fiduciary duties in connection with the proposed sale to Atlas Energy, Inc. of our interest in Laurel Mountain and that Atlas Energy, Inc. has been unjustly enriched. In the complaint, among other relief, the plaintiff requests damages and equitable and injunctive relief, as well as restitution and disgorgement from the individual defendants. On February 22, 2011, the plaintiff voluntarily dismissed its complaint without prejudice. We have not received an indication whether the plaintiff intends to reassert its claims in another forum. The defendants believe the claims are without merit.

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, 2010.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Securities Purchase Agreement, dated July 27, 2010, by and among Atlas Pipeline Mid-Continent, LLC, Atlas Pipeline Partners, L.P., Enbridge Pipelines (Texas Gathering) L.P. and Enbridge Energy Partners, L.P.[13]
2.2	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. [14]
3.1	Certificate of Limited Partnership[1]
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[10]
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership[15]
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership[16]
4.1	Common unit certificate[1]
4.2(a)	8 1/8% Senior Notes Indenture dated December 20, 2005[9]
4.2(b)	Supplemental Indenture dated November 22, 2010[17]
4.3	8 3/4% Senior Notes Indenture dated June 27, 2008[7]

4.4	Certificate of Designation for 12% Cumulative Class C Preferred Units of Atlas Pipeline Partners, L.P. [20]
10.1	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[18]
10.1(a)	Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011
10.2	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.[19]
10.3	Long-Term Incentive Plan[25]
10.4	Amended and Restated 2010 Long-Term Incentive Plan
10.5	Form of Grant of Phantom Units in Exchange for Bonus Units[21]
10.6	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter[22]
10.7	Form of Grant of Phantom Units to Non-Employee Managers[23]

Exhibit No.	Description
10.8	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan(25)
10.9	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement(25)
10.10	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay(11)
10.11	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras(12)
10.12	Phantom Unit Grant Agreement between Atlas Pipeline Mid-Continent, LLC and Eric Kalamaras, dated September 14, 2009(12)
10.13	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010(14)
10.14	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010(24)
10.15	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010(24)
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
31.1	Rule 13a-14(a)/15d-14(a) Certification
31.2	Rule 13a-14(a)/15d-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification

(1) Previously filed as an exhibit to registration statement on Form S-1 on January 20, 2000.
(2) Previously filed as an exhibit to registration statement on Form S-3 on April 2, 2004.
(3) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended June 30, 2007.
(4) Previously filed as an exhibit to current report on Form 8-K on July 30, 2007.
(5) Previously filed as an exhibit to current report on Form 8-K on January 8, 2008.
(6) Previously filed as an exhibit to current report on Form 8-K on June 16, 2008.
(7) Previously filed as an exhibit to current report on Form 8-K on 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 December 21, 2005.
(10) Previously filed as an exhibit to current report on Form 8-K on April 3, 2009.
(11) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.
(12) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2009.
(13) Previously filed as an exhibit to current report on Form 8-K on July 29, 2010.
(14) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
(15) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
(16) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
(17) Previously filed as an exhibit to current report on Form 8-K on November 26, 2010.
(18) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.
(19) Previously filed as an exhibit to current report on Form 8-K filed on April 2, 2010.
(20) Previously filed as an exhibit to current report on Form 8-K filed on July 7, 2010.
(21) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
(22) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
(23) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
(24) Previously filed as an exhibit to Atlas Energy, Inc.   s current report on Form 8-K filed on November 12, 2010.
(25) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.

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: May 4, 2011	By: /s/ EUGENE N. DUBAY Eugene N. Dubay Chief Executive Officer, President and Managing Board Member of the General Partner
Date: May 4, 2011	By: /s/ ERIC T. KALAMARAS Eric T. Kalamaras Chief Financial Officer of the General Partner
Date: May 4, 2011	By: /s/ ROBERT W. KARLOVICH, III Robert W. Karlovich, III Chief Accounting Officer of the General Partner