

SECURITIES AND EXCHANGE COMMISSION

FORM 10-Q

Quarterly report pursuant to sections 13 or 15(d)

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FILER

**ATLAS PIPELINE PARTNERS LP**

CIK: **1092914** | IRS No.: **233011077** | State of Incorpor.: **DE** | Fiscal Year End: **1231**  
Type: **10-Q** | Act: **34** | File No.: **001-14998** | Film No.: **111184885**  
SIC: **4922** Natural gas transmission

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**UNITED STATES  
SECURITIES AND EXCHANGE COMMISSION**

Washington, D.C. 20549

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**FORM 10-Q**

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(Mark One)

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

For the quarterly period ended September 30, 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

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**ATLAS PIPELINE PARTNERS, L.P.**

(Exact name of registrant as specified in its charter)

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**DELAWARE**

(State or other jurisdiction of  
incorporation or organization)

**23-3011077**

(I.R.S. Employer  
Identification No.)

**1550 Coraopolis Heights Road  
Moon Township, Pennsylvania**

(Address of principal executive office)

**15108**

(Zip code)

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

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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  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

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

The number of common units of the registrant outstanding on November 2, 2011 was 53,616,683.

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### Glossary of Terms

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

BPD	Barrels per day. Barrel - measurement for a standard US barrel is 42 gallons. Crude oil and condensate are generally reported in barrels.
BTU	British thermal unit, a basic measure of heat energy
Condensate	Liquid hydrocarbons present in casinghead gas that condense within the gathering system and are removed prior to delivery to the gas plant. This product is generally sold on terms more closely tied to crude oil pricing.
FASB	Financial Accounting Standards Board
Fractionation	The process used to separate an NGL stream into its individual components.
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
Keep-Whole	Contract with producer whereby plant operator pays for or returns gas having an equivalent BTU content to the gas received at the well-head.
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."

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**PART I. FINANCIAL INFORMATION**  
**ITEM 1. FINANCIAL STATEMENTS**  
**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES**  
**CONSOLIDATED BALANCE SHEETS (Unaudited)**  
**(in thousands)**

	September 30,	December 31,
	2011	2010
<b>ASSETS</b>		
<b>Current assets:</b>		
Cash and cash equivalents	\$167	\$164
Accounts receivable	117,978	99,759
Notes receivable	8,500	–
Current portion of derivative assets	11,887	–
Prepaid expenses and other	15,809	15,118
Total current assets	154,341	115,041
<b>Property, plant and equipment, net</b>	1,481,441	1,341,002
<b>Intangible assets, net</b>	109,052	126,379
<b>Investment in joint ventures</b>	86,688	153,358
<b>Long-term portion of derivative assets</b>	26,950	–
<b>Other assets, net</b>	21,841	29,068
Total assets	<u>\$1,880,313</u>	<u>\$1,764,848</u>
<b>LIABILITIES AND EQUITY</b>		
<b>Current liabilities:</b>		
Current portion of long-term debt	\$2,054	\$210
Accounts payable - affiliates	2,676	12,280
Accounts payable	45,279	29,382
Accrued liabilities	40,378	30,013
Accrued interest payable	5,896	1,921
Current portion of derivative liabilities	–	4,564
Accrued producer liabilities	89,658	72,996
Distribution payable	–	240
Total current liabilities	185,941	151,606
<b>Long-term portion of derivative liabilities</b>	–	5,608
<b>Long-term debt, less current portion</b>	423,927	565,764
<b>Other long-term liability</b>	127	223
<b>Commitments and contingencies</b>		
<b>Equity:</b>		
General Partner' s interest	24,639	20,066
Class C preferred limited partner' s interest	–	8,000
Common limited partners' interests	1,281,650	1,057,342
Accumulated other comprehensive loss	(6,106 )	(11,224 )
Total partners' capital	1,300,183	1,074,184
Non-controlling interest	(29,865 )	(32,537 )
Total equity	<u>1,270,318</u>	<u>1,041,647</u>

Total liabilities and equity

\$1,880,313

\$1,764,848

See accompanying notes to consolidated financial statements

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

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2011	2010	2011	2010
<b>Revenue:</b>				
Natural gas and liquids	\$341,498	\$220,478	\$937,975	\$641,978
Transportation, processing and other fees - third parties	11,612	9,810	31,280	29,472
Transportation, processing and other fees - affiliates	79	141	256	472
Other income (loss), net	26,591	(4,311 )	17,317	10,576
Total revenue and other income (loss), net	<u>379,780</u>	<u>226,118</u>	<u>986,828</u>	<u>682,498</u>
<b>Costs and expenses:</b>				
Natural gas and liquids	282,391	178,920	774,859	521,495
Plant operating	14,085	12,552	40,240	36,492
Transportation and compression	268	300	603	721
General and administrative	8,686	7,203	25,477	22,396
Compensation reimbursement - affiliates	463	375	1,344	1,125
Other costs	8	-	583	-
Depreciation and amortization	19,471	18,566	57,499	55,647
Interest	5,935	23,087	24,525	74,085
Total costs and expenses	<u>331,307</u>	<u>241,003</u>	<u>925,130</u>	<u>711,961</u>
Equity income in joint ventures	1,785	1,787	2,934	4,137
Gain on asset sale	-	-	255,674	-
Loss on early extinguishment of debt	-	(4,359 )	(19,574 )	(4,359 )
Income (loss) from continuing operations	<u>50,258</u>	<u>(17,457)</u>	<u>300,732</u>	<u>(29,685)</u>
<b>Discontinued operations:</b>				
Gain (loss) on sale of discontinued operations	-	311,492	(81 )	311,492
Earnings (loss) from discontinued operations	-	(5,565 )	-	9,192
Income (loss) from discontinued operations	<u>-</u>	<u>305,927</u>	<u>(81 )</u>	<u>320,684</u>
<b>Net income</b>	50,258	288,470	300,651	290,999
Income attributable to non-controlling interests	(1,760 )	(1,076 )	(4,492 )	(3,338 )
Preferred unit dividends	-	(240 )	(389 )	(240 )
Net income attributable to common limited partners and the General Partner	<u>\$48,498</u>	<u>\$287,154</u>	<u>\$295,770</u>	<u>\$287,421</u>



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

	<u>Three Months Ended</u>		<u>Nine Months Ended</u>	
	<u>September 30,</u>		<u>September 30,</u>	
	<u>2011</u>	<u>2010</u>	<u>2011</u>	<u>2010</u>
<b>Allocation of net income (loss) attributable to:</b>				
<b>Common limited partner interest:</b>				
Continuing operations	\$47,091	\$(18,414)	\$289,472	\$(32,627)
Discontinued operations	–	300,085	(79 )	314,559
	<u>47,091</u>	<u>281,671</u>	<u>289,393</u>	<u>281,932</u>
<b>General Partner interest:</b>				
Continuing operations	1,407	(359 )	6,379	(636 )
Discontinued operations	–	5,842	(2 )	6,125
	<u>1,407</u>	<u>5,483</u>	<u>6,377</u>	<u>5,489</u>
<b>Net income (loss) attributable to:</b>				
Continuing operations	48,498	(18,773 )	295,851	(33,263 )
Discontinued operations	–	305,927	(81 )	320,684
	<u>\$48,498</u>	<u>\$287,154</u>	<u>\$295,770</u>	<u>\$287,421</u>
<b>Net income (loss) attributable to common limited partners per unit:</b>				
<b>Basic:</b>				
Continuing operations	\$0.87	\$(0.34 )	\$5.37	\$(0.61 )
Discontinued operations	–	5.63	–	5.92
	<u>\$0.87</u>	<u>\$5.29</u>	<u>\$5.37</u>	<u>\$5.31</u>
Weighted average common limited partner units (basic)	<u>53,588</u>	<u>53,277</u>	<u>53,494</u>	<u>53,115</u>
<b>Diluted:</b>				
Continuing operations	\$0.87	\$(0.34 )	\$5.37	\$(0.61 )
Discontinued operations Diluted	–	5.63	–	5.92
	<u>\$0.87</u>	<u>\$5.29</u>	<u>\$5.37</u>	<u>\$5.31</u>
Weighted average common limited partner units (diluted)	<u>54,012</u>	<u>53,277</u>	<u>53,923</u>	<u>53,115</u>

See accompanying notes to consolidated financial statements

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**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES**  
**CONSOLIDATED STATEMENT OF EQUITY (Unaudited)**  
**FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2011**  
**(in thousands, except unit data)**

	Number of Limited		Class C	Common	General	Accumulated	Non-	Total
	Partner Units							
	Class C	Common	Limited	Limited	Partner	Comprehensive	Interest	
	Preferred	Common	Partner	Partners	Partner	Loss	Interest	
Balance at January 1, 2011	8,000	53,338,010	\$8,000	\$1,057,342	\$20,066	\$ (11,224 )	\$(32,537)	\$1,041,647
Redemption of Class C cumulative preferred limited partner units	(8,000 )	—	(8,000 )	—	—	—	—	(8,000 )
Issuance of units under incentive plans	—	306,275	—	468	—	—	—	468
Repurchase and retirement of common limited partner units	—	(28,878 )	—	(984 )	—	—	—	(984 )
Distributions paid	—	—	(629 )	(66,869 )	(1,804)	—	—	(69,302 )
Distributions payable	—	—	240	—	—	—	—	240
Distributions paid to non-controlling interests	—	—	—	—	—	—	(1,820 )	(1,820 )
Unissued units under incentive plans	—	—	—	2,300	—	—	—	2,300
Other comprehensive income	—	—	—	—	—	5,118	—	5,118
Net income	—	—	389	289,393	6,377	—	4,492	300,651
Balance at September 30, 2011	—	53,615,407	\$—	\$1,281,650	\$24,639	\$ (6,106 )	\$(29,865)	\$1,270,318

See accompanying notes to consolidated financial statements

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

	Nine Months Ended	
	September 30,	
	2011	2010
<b>CASH FLOWS FROM OPERATING ACTIVITIES:</b>		
Net income	\$300,651	\$290,999
Less: Income (loss) from discontinued operations	(81 )	320,684
Net income (loss) from continuing operations	300,732	(29,685 )
Adjustments to reconcile net income (loss) from continuing operations to net cash provided by operating activities:		
Depreciation and amortization	57,499	55,647
Equity income in joint ventures	(2,934 )	(4,137 )
Distributions received from joint ventures	2,548	8,276
Non-cash compensation expense	2,507	2,810
Amortization of deferred finance costs	3,354	4,729
Gain on asset sales	(255,674)	-
Loss on early extinguishment of debt	19,574	4,359
Change in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(18,950 )	19,106
Accounts payable and accrued liabilities	25,497	11,431
Accounts payable and accounts receivable - affiliates	(9,604 )	8,348
Derivative accounts payable and receivable	(43,891 )	(4,089 )
Net cash provided by continuing operating activities	80,658	76,795
Net cash provided by discontinued operating activities	-	24,490
Net cash provided by operating activities	80,658	101,285
<b>CASH FLOWS FROM INVESTING ACTIVITIES:</b>		
Capital contribution to equity investment	(12,250 )	(6,914 )
Capital expenditures	(148,144)	(31,194 )
Acquisition of equity investment	(85,000 )	-
Net proceeds related to asset sales	411,480	-
Other	(11 )	391
Net cash provided by (used in) continuing investing activities	166,075	(37,717 )
Net cash provided by (used in) discontinued investing activities	(81 )	667,605
Net cash provided by investing activities	165,994	629,888
<b>CASH FLOWS FROM FINANCING ACTIVITIES:</b>		
Borrowings under credit facility	995,500	273,000
Repayments under credit facility	(867,000)	(587,000)
Repayment of debt	(279,557)	(433,504)
Payment of premium on early retirement of debt	(14,342 )	-
Principal payments on capital lease	(452 )	(92 )
Net proceeds from issuance of common limited partner units	468	15,319
Purchase and retirement of treasury units	(984 )	-
Net proceeds from issuance of preferred limited partner units	-	8,000

Redemption of preferred limited partner units	(8,000 )	–
Net distributions to non-controlling interest holders	(1,820 )	(4,125 )
Distributions paid to common limited partners, the General Partner and preferred limited partners	(69,302 )	–
Other	(1,160 )	(3,626 )
Net cash used in financing activities	<u>(246,649)</u>	<u>(732,028)</u>
Net change in cash and cash equivalents	3	(855 )
Cash and cash equivalents, beginning of period	<u>164</u>	<u>1,021</u>
Cash and cash equivalents, end of period	<u>\$167</u>	<u>\$166</u>

See accompanying notes to consolidated financial statements

**ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**SEPTEMBER 30, 2011**  
**(Unaudited)**

**NOTE 1 - BASIS OF PRESENTATION**

Atlas Pipeline Partners, L.P. (the "Partnership") is a publicly-traded (NYSE: APL) Delaware limited partnership engaged in the gathering and processing of natural gas in the Mid-Continent and Appalachia regions and the transportation of NGLs in the Mid-Continent. 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 September 30, 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, a publicly-traded partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At September 30, 2011, the Partnership had 53,615,407 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.

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. common units it held. On May 27, 2011, the Partnership redeemed the 8,000 \$1,000 par value 12% cumulative Class C preferred limited partner units held by Chevron (see Note 5).

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-Q from amounts previously presented to reflect the reclassification of accelerated amortization of deferred financing costs. The Partnership has retrospectively adjusted its prior period consolidated financial statements to reclass the amounts from interest expense to loss on early extinguishment of debt.

The accompanying consolidated financial statements, which are unaudited except 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 nine month period ended September 30, 2011 may not necessarily be indicative of the results of operations for the full year ending December 31, 2011.

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### 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 6.3% and 7.7% for the three months ended September 30, 2011 and 2010, respectively, and 7.2% and 7.5% for the nine months ended September 30, 2011 and 2010, respectively. The amount of interest capitalized was \$1.7 million and \$0.2 million for the three months ended September 30, 2011 and 2010, respectively, and \$3.0 million and \$0.6 million for the nine months ended September 30, 2011 and 2010, respectively.

#### *Capital Leases*

Leased property and equipment meeting capital lease criteria are capitalized based on the minimum payments required under the lease and are included within property plant and equipment on the Partnership's consolidated balance sheets. Obligations under capital leases are accounted for as current and noncurrent liabilities and are included within debt on the Partnership's consolidated balance sheets. Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets.

#### *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 September 30, 2011 and December 31, 2010 (in thousands):

	September 30, 2011	December 31, 2010	Estimated Useful Lives In Years
<b>Customer relationships:</b>			
Gross carrying amount	\$ 205,313	\$ 205,313	7- 10
Accumulated amortization	(96,261 )	(78,934 )	
Net carrying amount	<u>\$ 109,052</u>	<u>\$ 126,379</u>	

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. The weighted-average amortization period for customer relationships is 9.1 years. The Partnership recorded amortization expense on intangible assets of \$5.8 million for both the three months ended September 30, 2011 and 2010, and \$17.3 million for both the nine months ended September 30, 2011 and 2010 on its consolidated statements of operations.

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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.

### *Stock-Based Compensation*

All share-based payments to employees, including grants of employee stock options, are recognized in the financial statements based on their fair values. Share-based awards, which have a cash option, are classified as liabilities on the Partnership's consolidated balance sheets. All other share-based awards are classified as equity on the Partnership's consolidated balance sheets. Compensation expense associated with share-based payments is recognized within general and administrative expenses on the Partnership's statements of operations from the date of the grant through the date of vesting, amortized on a straight-line method. Generally, no expense is recorded for awards that do not vest due to forfeiture.

### *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 6), with a priority allocation of net income to the General Partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership's phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 13), 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.

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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		Nine Months Ended	
	September 30,		September 30,	
	2011	2010	2011	2010
<b>Continuing operations:</b>				
Net income (loss)	\$50,258	\$(17,457)	\$300,732	\$(29,685)
Income attributable to non-controlling interest	(1,760)	(1,076)	(4,492)	(3,338)
Preferred unit dividends	–	(240)	(389)	(240)
Net income (loss) attributable to common limited partners and the General Partner	48,498	(18,773)	295,851	(33,263)
General Partner's cash incentive distributions paid	441	–	441	–
General Partner's ownership interest	966	(358)	5,938	(636)
Net income (loss) attributable to the General Partner's ownership interests	1,407	(358)	6,379	(636)
Net income (loss) attributable to common limited partners	47,091	(18,415)	289,472	(32,627)
Net income attributable to participating securities - phantom units <sup>(1)</sup>	369	–	2,301	–
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	<u>\$46,722</u>	<u>\$(18,415)</u>	<u>\$287,171</u>	<u>\$(32,627)</u>
<b>Discontinued operations:</b>				
Net income (loss)	\$–	\$305,927	\$(81)	\$320,684
Net income (loss) attributable to the General Partner's ownership interests	–	5,842	(2)	6,125
Net income (loss) utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	<u>\$–</u>	<u>\$300,085</u>	<u>\$(79)</u>	<u>\$314,559</u>

- (1) Net income attributable to common limited partners' ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three and nine months ended September 30, 2010, net loss attributable to common limited partners' ownership interest is not allocated to approximately 532,000 and 234,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities and unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plans (see Note 13).

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):



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	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2011	2010	2011	2010
Weighted average number of common limited partner units - basic	53,588	53,277	53,494	53,115
Add effect of participating securities - phantom units <sup>(1)</sup>	424	–	429	–
Add effect of dilutive option incentive awards <sup>(2)</sup>	–	–	–	–
Weighted average common limited partner units - diluted	<u>54,012</u>	<u>53,277</u>	<u>53,923</u>	<u>53,115</u>

- (1) For the three and nine months ended September 30, 2010, approximately 532,000 and 234,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such phantom units would have been anti-dilutive.
- (2) For the three and nine months ended September 30, 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. There were no unit options outstanding for the three and nine months ended September 30, 2011.

### *Comprehensive Income*

Comprehensive income 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” 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 9). The following table sets forth the calculation of the Partnership’s comprehensive income (in thousands):

	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2011	2010	2011	2010
Net income	\$50,258	\$288,470	\$300,651	\$290,999
Income attributable to non-controlling interests	(1,760)	(1,076 )	(4,492 )	(3,338 )
Preferred unit dividends	–	(240 )	(389 )	(240 )
Net income attributable to common limited partners and the General Partner	<u>48,498</u>	<u>287,154</u>	<u>295,770</u>	<u>287,421</u>
<b>Other comprehensive income:</b>				
Adjustment for realized losses on derivatives reclassified to net income	1,714	14,122	5,118	35,555
Comprehensive income	<u>\$50,212</u>	<u>\$301,276</u>	<u>\$300,888</u>	<u>\$322,976</u>

### *Revenue Recognition*

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

*Fee-Based Contracts.* These contracts provide a set fee for gathering and/or processing raw natural gas and for transporting NGLs. Revenue is a function of the volume of natural gas that the



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Partnership gathers and processes or the volume of NGLs transported and is not directly dependent on the value of the natural gas or NGLs. The Partnership is also paid a separate compression fee on many of its gathering systems. The fee is dependent upon the volume of gas flowing through its compressors and the quantity of compression stages utilized to gather the gas.

*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 the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements is 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 September 30, 2011 and December 31, 2010 of \$66.1 million and \$57.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

### *Recently Issued Accounting Standards*

In May 2011, the FASB issued Accounting Standards Update (“ASU”) 2011-04, “Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs,” which, among other changes, requires (1) additional disclosures for fair value measurements categorized within Level 2 and Level 3 of the fair value hierarchy; and (2) additional disclosures for items not measured at fair value in the Partnership’s consolidated balance sheets but for which the fair value is required to be disclosed. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. Early adoption is prohibited. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and results of operations.

In June 2011, the FASB issued ASU 2011-05, “Comprehensive Income (Topic 220) – Presentation of Comprehensive Income,” which, among other changes, eliminates the option to present components of other comprehensive income as part of the statement of changes in equity. The

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amendments in this update require “all nonowner changes in equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements.” The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. Early adoption is permitted. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and results of operations.

### **NOTE 3 - INVESTMENT IN JOINT VENTURES**

#### *Laurel Mountain*

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain 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 on its consolidated statements of operations a net gain on the sale of assets of \$253.5 million. The Partnership recognized a \$255.7 million gain during the nine months ended September 30, 2011 and a \$2.2 million loss during the year ended December 31, 2010 for expenses related to the sale. 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 11) and for general company 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 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 reclassify the earnings or the gain on sale related to Laurel Mountain to discontinued operations upon the sale of its ownership interest.

The Partnership retained its preferred distribution rights with respect to a \$25.5 million note receivable due from Williams, an investment grade rated entity, related to the formation of Laurel Mountain in 2009, including interest due on this note. Interest is received on the last day of each quarter. The preferred distribution rights with respect to the note receivable have been reclassified from investment in joint ventures to 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. During the three and nine months ended September 30, 2010, the Partnership utilized \$8.5 million and \$15.3 million of the note receivable, respectively, and made cash payments of \$1.3 million and \$6.9 million, respectively, for capital contributions to Laurel Mountain. As of September 30, 2011, the Partnership has utilized \$17.0 million of the \$25.5 million note receivable, resulting in a remaining balance of \$8.5 million.

#### *West Texas LPG Pipeline Limited Partnership*

On May 11, 2011, the Partnership acquired a 20% interest in West Texas LPG Pipeline Limited Partnership (“WTLPG”) from Buckeye Partners, L.P. (NYSE: BPL) for \$85.0 million. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu,

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Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest. The Partnership recognizes its 20% interest in WTLPG as an investment in joint venture on its consolidated balance sheets. The Partnership accounts for its ownership interest in WTLPG under the equity method of accounting, with recognition of its ownership interest in the income of WTLPG as equity income on its consolidated statements of operations. The Partnership incurred costs of \$0.6 million during the nine months ended September 30, 2011, related to the acquisition of WTLPG, which are reported as other costs within the Partnership's consolidated statements of operations.

The following tables summarize the components of the investment in joint ventures on the Partnership's consolidated balance sheets and the components of equity income on the Partnership's statements of operations (in thousands).

	September 30, 2011	December 31, 2010
Investment in Laurel Mountain	\$ –	\$ 153,358
Investment in WTLPG	86,688	–
Investment in joint ventures	<u>\$ 86,688</u>	<u>\$ 153,358</u>

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Equity income in Laurel Mountain	\$–	\$1,787	\$462	\$4,137
Equity income in WTLPG	1,785	–	2,472	–
Equity income in joint ventures	<u>\$1,785</u>	<u>\$1,787</u>	<u>\$2,934</u>	<u>\$4,137</u>

### 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 nine months ended September 30, 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 included within the Partnership's formerly reported Mid-Continent segment of operations, which was reclassified to the Partnership's current Gathering and Processing segment of operations (see Note 15).

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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Total revenue and other income (loss), net	\$–	\$29,912	\$–	\$129,928
Total costs and expenses	–	(35,477 )	–	(120,736)
Gain (loss) on asset sales and other	–	311,492	(81)	311,492
Income (loss) from discontinued operations	<u>\$–</u>	<u>\$305,927</u>	<u>\$(81)</u>	<u>\$320,684</u>

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The Partnership's continuing operations include \$0.6 million and \$18.0 million within natural gas and liquids revenue on the consolidated statements of operations for the three and nine months ended September 30, 2010, respectively, for intercompany sales from the WestOK system to Elk City. These intercompany sales were previously eliminated in consolidation prior to the sale of Elk City and were reinstated within natural gas and liquids revenue from continuing operations upon the sale of Elk City. In the periods subsequent to the sale of Elk City, these sales have been made directly to third parties.

### **NOTE 5 - PREFERRED UNIT EQUITY OFFERINGS**

On June 30, 2010, the Partnership sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the "Class C Preferred Units") to Atlas Energy, Inc. for cash consideration of \$1,000 per Class C Preferred Unit (the "Class C Preferred Unit Face Value"). The Class C Preferred Units were entitled to receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for the Partnership's common units. The Class C Preferred Units were not convertible into common units of the Partnership. The Partnership had the right at any time to redeem some or all of the outstanding Class C Preferred Units for cash at an amount equal to the Class C Preferred Face Value being redeemed plus accrued but unpaid dividends.

On February 17, 2011, the Class C Preferred Units were acquired by Chevron as part of the Chevron Merger (see Note 1). On May 27, 2011, the Partnership redeemed all 8,000 Class C Preferred Units outstanding for cash at the liquidation value of \$1,000 per unit, or \$8.0 million, plus \$0.2 million, representing the accrued dividends on the 8,000 Class C Preferred Units prior to the Partnership's redemption. There are no longer any Class C Preferred Units outstanding. The Partnership recognized \$0.2 million of preferred dividend cost for the three months ended September 30, 2010 and \$0.4 million and \$0.2 million of preferred dividend cost for the nine months ended September 30, 2011 and 2010, respectively, which are presented as reductions of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations.

### **NOTE 6 - CASH DISTRIBUTIONS**

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership from January 1, 2010 through September 30, 2011 were as follows:

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<u>For Quarter Ended</u>	<u>Date Cash Distribution Paid</u>	<u>Cash Distribution Per Common Limited Partner Unit</u>	<u>Total Cash Distribution to Common Limited Partners (in thousands)</u>	<u>Total Cash Distribution to the General Partner (in thousands)</u>
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
March 31, 2011	May 13, 2011	0.40	21,400	439
June 30, 2011	August 12, 2011	0.47	25,184	967

On October 26, 2011, the Partnership declared a cash distribution of \$0.54 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2011. The \$30.8 million distribution, including \$1.8 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on November 14, 2011 to unitholders of record at the close of business on November 7, 2011.

### **NOTE 7 - PROPERTY, PLANT AND EQUIPMENT**

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 11) (in thousands):

	<u>September 30, 2011</u>	<u>December 31, 2010</u>	<u>Estimated Useful Lives in Years</u>
Pipelines, processing and compression facilities	\$1,517,573	\$1,340,944	2 - 40
Rights of way	158,602	156,713	20 - 40
Buildings	8,047	8,047	40
Furniture and equipment	9,404	8,981	3 - 7
Other	13,800	12,659	3 - 10
	<u>1,707,426</u>	<u>1,527,344</u>	
Less - accumulated depreciation	<u>(225,985 )</u>	<u>(186,342 )</u>	
	<u>\$1,481,441</u>	<u>\$1,341,002</u>	

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. 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. The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 11), of \$13.8 million and \$12.8 million for the three months ended September 30, 2011 and 2010, respectively, and \$40.2 million and \$38.3 million for the nine months ended September 30, 2011 and 2010, respectively, on its consolidated statements of operations.

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### NOTE 8 - OTHER ASSETS

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

	September 30, 2011	December 31, 2010
Deferred finance costs, net of accumulated amortization of \$17,739 and \$24,436 at September 30, 2011 and December 31, 2010, respectively	\$ 18,988	\$ 26,227
Security deposits	2,853	2,841
	<u>\$ 21,841</u>	<u>\$ 29,068</u>

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11). During the nine months ended September 30, 2011, the Partnership recorded \$5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of its 8.125% Senior Notes and partial redemption of its 8.75% Senior Notes, which is included in loss on early extinguishment of debt on the Partnership's consolidated statements of operations (see Note 11). During the three and nine months ended September 2010, the Partnership recorded \$4.4 million of accelerated amortization of deferred financing costs associated with the retirement of its term loan with proceeds from the sale of its Elk City assets (see Note 4), which is included in loss on early extinguishment of debt on the Partnership's consolidated statements of operations. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was \$1.1 million and \$1.5 million for the three months ended September 30, 2011 and 2010, respectively, and \$3.4 million and \$4.7 million for the nine months ended September 30, 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 - \$4.4 million; 2012 to 2014 - \$4.2 million per year; 2015 - \$3.9 million.

### NOTE 9 - DERIVATIVE INSTRUMENTS

The Partnership uses derivative instruments in connection with its commodity price 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 its derivatives. As such, changes in fair value of derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership's consolidated balance sheets, will be reclassified to the Partnership's consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings. The Partnership will



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reclassify \$4.7 million of the \$6.1 million net loss in accumulated other comprehensive loss, within equity on the Partnership's consolidated balance sheets at September 30, 2011, to natural gas and liquids revenue on the Partnership's consolidated statements of operations over the next twelve-month period. Aggregate losses of \$1.4 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 assets on its consolidated balance sheet of \$38.8 million at September 30, 2011 and net derivative liabilities on its consolidated balance sheet of \$10.2 million at December 31, 2010.

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

	<u>September 30,</u> <u>2011</u>	<u>December 31,</u> <u>2010</u>
Current portion of derivative assets	\$ 11,887	\$-
Long-term portion of derivative assets	26,950	-
Current portion of derivative liabilities	-	(4,564 )
Long-term portion of derivative liabilities	-	(5,608 )
Net derivative assets/(liabilities)	<u>\$ 38,837</u>	<u>\$(10,172 )</u>

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

<u>Balance Sheet Location</u>	<u>September 30,</u> <u>2011</u>	<u>December 31,</u> <u>2010</u>
<b><u>Asset Derivatives</u></b>		
Current portion of derivative assets	\$ 17,582	\$-
Long-term portion of derivative assets	28,522	-
Current portion of derivative liabilities	-	2,624
Long-term portion of derivative liabilities	-	1,052
Total assets	<u>46,104</u>	<u>3,676</u>
<b><u>Liability Derivatives</u></b>		
Current portion of derivative assets	(5,695 )	-
Long-term portion of derivative assets	(1,572 )	-
Current portion of derivative liabilities	-	(7,188 )
Long-term portion of derivative liabilities	-	(6,660 )
Total liabilities	<u>(7,267 )</u>	<u>(13,848 )</u>
<b>Total Derivatives</b>	<u>\$ 38,837</u>	<u>\$(10,172 )</u>

The following table summarizes the Partnership's commodity derivatives as of September 30, 2011, none of which are designated for hedge accounting (dollars and volumes in thousands):

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### Fixed Price Swaps

<u>Production Period</u>	<u>Purchased/ Sold</u>	<u>Commodity</u>	<u>Volumes<sup>(1)</sup></u>	<u>Average Fixed Price</u>	<u>Fair Value<sup>(2)</sup> Asset/ (Liability)</u>
<b><u>Natural Gas</u></b>					
2011	Sold	Natural Gas Basis	480	\$(0.728 )	\$ (284 )
2011	Purchased	Natural Gas Basis	480	(0.758 )	298
2011	Sold	Natural Gas	1,200	4.910	1,337
<b><u>Natural Gas Liquids</u></b>					
2011	Sold	Ethane	2,142	0.730	(136 )
2011	Sold	Propane	4,284	1.190	(1,342 )
2011	Sold	Isobutane	504	1.628	(244 )
2011	Sold	Normal Butane	1,386	1.590	(396 )
2011	Sold	Natural Gasoline	3,276	2.042	(231 )
2012	Sold	Ethane	1,890	0.700	(5 )
2012	Sold	Propane	19,278	1.302	(527 )
2012	Sold	Normal Butane	3,276	1.902	440
2012	Sold	Isobutane	504	1.970	(13 )
2012	Sold	Natural Gasoline	4,158	2.401	1,807
<b><u>Crude Oil</u></b>					
2011	Sold	Crude Oil	30	90.75	343
2012	Sold	Crude Oil	180	103.76	4,100
<b>Total Fixed Price Swaps</b>					<b>\$ 5,147</b>

### Options

<u>Production Period</u>	<u>Purchased/ Sold</u>	<u>Type</u>	<u>Commodity</u>	<u>Volumes<sup>(1)</sup></u>	<u>Average Strike Price</u>	<u>Fair Value<sup>(2)</sup> Asset/ (Liability)</u>
<b><u>Natural Gas Liquids</u></b>						
2011	Purchased	Put	Ethane	2,142	\$0.735	\$ 57
2011	Purchased	Put	Propane	5,040	1.383	292
2012	Purchased	Put	Ethane	1,890	0.700	157
2012	Purchased	Put	Propane	28,476	1.386	6,476
2012	Purchased	Put	Natural Gasoline	2,520	2.400	950
2013	Purchased	Put	Normal Butane	10,458	1.667	3,459
2013	Purchased	Put	Isobutane	4,158	1.687	1,311
2013	Purchased	Put	Natural Gasoline	23,940	2.108	10,219
<b><u>Crude Oil</u></b>						
2011	Purchased	Put	Crude Oil	93	99.45	1,911
2011	Sold	Call	Crude Oil	170	93.35	(208 )
2011	Purchased <sup>(3)</sup>	Call	Crude Oil	63	125.20	3
2012	Purchased	Put	Crude Oil	180	106.42	5,146
2012	Sold	Call	Crude Oil	498	94.69	(3,210 )
2012	Purchased <sup>(3)</sup>	Call	Crude Oil	180	125.20	301

2013	Purchased	Put	Crude Oil	282	100.10	<u>6,826</u>
<b>Total Options</b>						<u>\$ 33,690</u>
<b>Total Fair Value</b>						<u><u>\$ 38,837</u></u>

- (1) Volumes for natural gas are stated in MMBTU' s. Volumes for NGLs are stated in gallons. Volumes for crude oil are stated in barrels.
- (2) See Note 10 for discussion on fair value methodology.
- (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.

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During the nine months ended September 30, 2010, the Partnership made net payments of \$25.3 million related to the early termination of derivative contracts, which were recorded within the Partnership's consolidated statements of operations. The terminated derivative contracts were to expire at various times through the fourth quarter of 2010. No contracts were terminated early during the nine months ended September 30, 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):

		<u>For the Three Months</u>		<u>For the Nine Months</u>	
		<u>ended September 30,</u>		<u>ended September 30,</u>	
		<u>2011</u>	<u>2010</u>	<u>2011</u>	<u>2010</u>
<b><u>Loss reclassified from Accumulated other comprehensive loss into Income</u></b>					
<b><u>Contract Type</u></b>	<b><u>Location</u></b>				
Interest rate contracts <sup>(1)</sup>	Interest expense	\$-	\$-	\$-	\$(2,242 )
Commodity contracts <sup>(1)</sup>	Natural gas and liquids revenue	(1,714)	(2,411 )	(5,118)	(13,159)
Commodity contracts <sup>(1)</sup>	Discontinued operations	-	(11,711)	-	(20,154)
Loss reclassified from Accumulated other comprehensive loss		<u>\$(1,714)</u>	<u>\$(14,122)</u>	<u>\$(5,118)</u>	<u>\$(35,555)</u>
<b><u>Gain (loss) recognized in income (derivatives not designated as hedges)</u></b>					
<b><u>Contract type</u></b>	<b><u>Location</u></b>				
Interest rate contracts <sup>(2)</sup>	Other income (loss), net	\$-	\$-	\$-	\$(6 )
Commodity contracts <sup>(2)</sup>	Other income (loss), net	23,760	(6,802 )	8,952	3,139
Commodity contracts <sup>(2)</sup>	Discontinued operations	-	(1,555 )	-	665
Gain (loss) recognized in income		<u>\$23,760</u>	<u>\$(8,357 )</u>	<u>\$8,952</u>	<u>\$3,798</u>

- (1) Hedges previously designated as cash flow hedges  
(2) Dedicating cash flow hedges and non-designated hedges

## **NOTE 10 - FAIR VALUE OF FINANCIAL INSTRUMENTS**

### *Derivative Instruments*

The Partnership uses a valuation framework based upon inputs 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.

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*Level 3* - Unobservable inputs that reflect the entity's own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather 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 9). At September 30, 2011, all 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 September 30, 2011 and December 31, 2010 (in thousands):

	<u>Level 1</u>	<u>Level 2</u>	<u>Level 3</u>	<u>Total</u>
<b><u>September 30, 2011</u></b>				
<b>Assets</b>				
Commodity swaps	\$ –	\$6,433	\$2,564	\$8,997
Commodity options	–	14,186	22,921	37,107
Total assets	–	20,619	25,485	46,104
<b>Liabilities</b>				
Commodity swaps	–	(638 )	(3,212 )	(3,850 )
Commodity options	–	(3,417 )	–	(3,417 )
Total liabilities	–	(4,055 )	(3,212 )	(7,267 )
Total derivatives	<u>\$ –</u>	<u>\$16,564</u>	<u>\$22,273</u>	<u>\$38,837</u>
<b><u>December 31, 2010</u></b>				
<b>Assets</b>				
Commodity swaps	\$ –	\$1,225	\$124	\$1,349
Commodity options	–	2,327	–	2,327
Total assets	–	3,552	124	3,676
<b>Liabilities</b>				
Commodity swaps	–	(1,461 )	(1,914 )	(3,375 )
Commodity options	–	(10,473)	–	(10,473)
Total liabilities	–	(11,934)	(1,914)	(13,848)
Total derivatives	<u>\$ –</u>	<u>\$(8,382 )</u>	<u>\$(1,790)</u>	<u>\$(10,172)</u>

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 nine months ended September 30, 2011 (in thousands):

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	<u>NGL Fixed Price Swaps</u>		<u>NGL Put Options</u>		<u>Total</u>
	<u>Volume</u>	<u>Amount</u>	<u>Volume</u>	<u>Amount</u>	<u>Amount</u>
Balance - December 31, 2010	32,760	\$(1,790 )	–	\$–	\$(1,790 )
New contracts <sup>(1)</sup>	37,464	–	89,628	22,360	22,360
Cash settlements from unrealized gain (loss) <sup>(2)(3)</sup>	(29,526 )	8,103	(11,004)	1,352	9,455
Net change in unrealized gain (loss) <sup>(2)</sup>	–	(6,961 )	–	593	(6,368 )
Deferred option premium recognition <sup>(3)</sup>	–	–	–	(1,384 )	(1,384 )
Balance - September 30, 2011	<u>40,698</u>	<u>\$(648 )</u>	<u>78,624</u>	<u>\$22,921</u>	<u>\$22,273</u>

- (1) Swaps are entered into with no value on the date of trade. Options include premiums paid, which are included in the value of the derivatives on the date of trade.
- (2) Included within other income (loss), net on the Partnership' s consolidated statements of operations.
- (3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

### *Other Financial Instruments*

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

The Partnership' s current assets and liabilities on its consolidated balance sheets, other than the derivatives 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 September 30, 2011 and December 31, 2010, which consists principally of borrowings under the revolving credit facility, the 8.125% Senior Notes and the 8.75% Senior Notes, were \$429.2 million and \$532.3 million, respectively, compared with the carrying amounts of \$426.0 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, approximate their estimated fair value.

### **NOTE 11 - DEBT**

Total debt consists of the following (in thousands):

	<u>September 30,</u> <u>2011</u>	<u>December 31,</u> <u>2010</u>
Revolving credit facility	\$ 198,500	\$ 70,000
8.125% Senior notes - due 2015	–	272,181
8.75% Senior notes - due 2018	215,822	223,050
Capital lease obligations	11,659	743
Total debt	425,981	565,974
Less current maturities	(2,054 )	(210 )
Total long term debt	<u>\$ 423,927</u>	<u>\$ 565,764</u>

Cash payments for interest related to debt, excluding payments related to early retirement of debt and net of capitalized interest, were \$3 thousand and \$11.4 million for the three months ended September 30, 2011 and 2010, respectively, and \$17.2 million and \$65.9 million for the nine months ended September 30, 2011 and 2010, respectively.

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### *Revolving Credit Facility*

At September 30, 2011, the Partnership had a \$450.0 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 weighted average interest rate for borrowings on the revolving credit facility, at September 30, 2011, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$1.1 million was outstanding at September 30, 2011. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At September 30, 2011, the Partnership had \$250.4 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 the Partnership's property and that of its subsidiaries, except for the assets owned by WestOK and WestTX joint ventures; and by the guaranty of each of the Partnership's consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including 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 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 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 September 30, 2011, the Partnership was in compliance with all covenants under the revolving credit facility.

### *Senior Notes*

At September 30, 2011, the Partnership had \$215.8 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 ("8.75% Senior Notes"). Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% Senior Notes are subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The 8.75% Senior Notes are junior in right of payment to the Partnership's secured debt, including the Partnership's obligations under its revolving credit facility.

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

The indenture governing the 8.75% Senior Notes contains covenants, including limitations of the Partnership's ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire

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equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all its assets. The Partnership is in compliance with these covenants as of September 30, 2011.

On April 8, 2011, the Partnership redeemed all of the 8.125% senior unsecured notes due on December 15, 2015 (“8.125% Senior Notes”). The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. The Partnership paid \$293.7 million to redeem the \$275.5 million principal plus \$11.2 million premium and \$7.0 million accrued interest. There were no 8.125% Senior Notes outstanding at September 30, 2011.

### *Capital Leases*

On July 15, 2011, the Partnership amended an operating lease for eight natural gas compressors to include a mandatory purchase of the equipment at the end of the lease term, thereby converting the agreement to a capital lease upon the effective date of the amendment. As a result, the Partnership recorded an asset of \$11.4 million within property, plant and equipment and recorded an offsetting liability within long term debt on the Partnership’s consolidated balance sheets. This amount was based on the minimum payments required under the lease and the Partnership’s incremental borrowing rate. During the nine months ended September 30, 2010, the Partnership entered into capital lease arrangements having obligations of \$0.9 million at inception, which were recorded within property, plant and equipment with an offsetting liability recorded within long term debt on the Partnership’s consolidated balance sheets.

The following is a summary of the leased property under capital leases, which are included within property, plant and equipment (see Note 7) (in thousands):

	September 30, 2011	December 31, 2010
Pipelines, processing and compression facilities	\$ 12,507	\$ 1,139
Less - accumulated depreciation	(185 )	(47 )
	<u>\$ 12,322</u>	<u>\$ 1,092</u>

Amortization expense for leased properties was \$109 thousand and \$14 thousand for the three months ended September 30, 2011 and 2010, respectively, and \$137 thousand and \$33 thousand for the nine months ended September 30, 2011 and 2010, respectively, which is included within depreciation and amortization expense on the Partnership’s consolidated statements of operations (see Note 7).

As of September 30, 2011, future minimum lease payments related to the capital leases are as follows (in thousands):



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	<b>Capital Lease Minimum Payments</b>
2011	\$ 671
2012	2,685
2013	9,376
2014	64
2015	-
Thereafter	-
Total minimum lease payments	12,796
Less amounts representing interest	(1,137 )
Present value of minimum lease payments	11,659
Less current capital lease obligations	(2,054 )
Long-term capital lease obligations	<u>\$ 9,605</u>

### **NOTE 12 - COMMITMENTS AND CONTINGENCIES**

The Partnership has certain long-term unconditional purchase obligations and commitments, primarily take-or-pay agreements. These agreements provide transportation services to be used in the ordinary course of the Partnership's operations.

The Partnership is, or may become, a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes 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 aggregate cap (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.

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There were no substantive developments with respect to Williams' indemnity claims during the three months ended September 30, 2011. As previously reported, 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 may be entitled to indemnification from Atlas Energy, Inc. with respect to a small portion of Williams' claims.

### **NOTE 13 - BENEFIT PLANS**

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

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted a distribution equivalent right ("DER"), which is the right to receive cash per phantom unit in an amount equal to and at the same time as the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. Except for phantom units awarded to non-employee managing board members of the General Partner and within the guidelines proscribed in each long term incentive plan, a committee (the "LTIP Committee") appointed by the General Partner's managing board determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The LTIP Committee shall determine how the exercise price may be paid by the grantee. The LTIP Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

#### *Long-Term Incentive Plans*

The Partnership has a 2004 Long-Term Incentive Plan ("2004 LTIP") and a 2010 Long-Term Incentive Plan, 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 September 30, 2011, the Partnership had 389,765 phantom units outstanding under the Partnership's LTIPs, with 2,370,779 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options, which have vested and have been exercised.

*Partnership Phantom Units.* Through September 30, 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 may automatically vest upon a change of control, as defined in the LTIPs. At September 30, 2011, there were 193,248 units outstanding under the LTIPs that will vest within the following twelve months. The Partnership is authorized to repurchase common units to cover employee-related taxes on certain phantom units when they have vested. The Partnership purchased and retired 5,533 common units during both the three months ending

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September 30, 2011 and 2010 for a cost of \$0.2 million and \$0.1 million, respectively, and purchased 28,878 common units and 20,442 common units during the nine months ended September 30, 2011 and 2010, respectively for a cost of \$1.0 million and \$0.2 million, respectively, which was recorded as a reduction of Partners' capital on the Partnership's consolidated balance sheet. 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 represented all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at September 30, 2011 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were \$0.2 and \$0.6 million during the three months and nine months ended September 30, 2011, respectively. These amounts were recorded as a reduction of Partners' capital on the Partnership's consolidated balance sheets. No DERs were paid during the nine months ended September 30, 2010.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	Number of Units	Fair Value <sup>(1)</sup>	Number of Units	Fair Value <sup>(1)</sup>	Number of Units	Fair Value <sup>(1)</sup>	Number of Units	Fair Value <sup>(1)</sup>
Outstanding, beginning of period	436,425	\$17.84	603,774	\$12.24	490,886	\$11.75	52,233	\$39.72
Granted	7,465	27.30	500	13.90	138,318	32.99	564,000	10.34
Matured and issued <sup>(2)</sup>	(46,375)	11.02	(103,625)	11.15	(231,689)	11.31	(114,209)	14.10
Forfeited	(7,750)	26.99	(4,500)	14.83	(7,750)	26.99	(5,875)	21.65
Outstanding, end of period <sup>(3)(4)</sup>	<u>389,765</u>	<u>\$19.24</u>	<u>496,149</u>	<u>\$12.43</u>	<u>389,765</u>	<u>\$19.24</u>	<u>496,149</u>	<u>\$12.43</u>
Matured and not issued <sup>(5)</sup>	<u>750</u>	<u>\$11.12</u>	<u>250</u>	<u>\$44.51</u>	<u>750</u>	<u>\$11.12</u>	<u>250</u>	<u>\$44.51</u>
Non-cash compensation expense recognized (in thousands) <sup>(6)</sup>		<u>\$822</u>		<u>\$763</u>		<u>\$2,498</u>		<u>\$2,788</u>

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

(2) The intrinsic values for phantom unit awards exercised during the three months ended September 30, 2011 and 2010 were \$1.5 million and \$1.2 million, respectively, and \$7.4 million and \$1.3 million during the nine months ended September 30, 2011 and 2010, respectively.

(3) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2011 and 2010 was \$11.6 million and \$8.7 million, respectively.

(4) There were 15,701 and 3,898 outstanding phantom unit awards at September 30, 2011 and 2010, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.

(5) The aggregate intrinsic value for phantom unit awards vested but not issued at September 30, 2011 and 2010 was \$24 thousand and \$3 thousand, respectively.

(6) Non-cash compensation expense for the nine months ended September 30, 2011 includes incremental compensation expense of \$472 thousand, related to the accelerated vesting of phantom units held by the CEO of the General Partner. Non-cash compensation expense includes \$0.2 million and \$2.0 million related to Bonus Units converted to phantom units during the three and nine months ended September 30, 2010, respectively.

At September 30, 2011, the Partnership had approximately \$4.9 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.2 years.

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*Partnership Unit Options.* At September 30, 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 September 30, 2011, all unit options were exercised.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	–	\$ –	100,000	\$ 6.24	75,000	\$ 6.24	100,000	\$ 6.24
Exercised <sup>(1)</sup>	–	–	(3,000 )	6.24	(75,000)	6.24	(3,000 )	6.24
Outstanding, end of period <sup>(2)(3)</sup>	–	\$ –	97,000	\$ 6.24	–	\$ –	97,000	\$ 6.24
Options exercisable, end of period <sup>(4)</sup>	–	\$ –	22,000	\$ 6.24	–	\$ –	22,000	\$ 6.24
Non-cash compensation expense recognized (in thousands) <sup>(5)</sup>		\$ –		\$ 1		\$ 3		\$ 3

- (1) The intrinsic value for option unit awards exercised during the three months ended September 2010 was \$0.1 million. The intrinsic values for option unit awards exercised during the nine months ended September 30, 2011 and 2010 were \$1.8 million and \$0.1 million, respectively. Approximately \$19 thousand was received from exercise of unit option awards during the three months ended September 30, 2010. Approximately \$468 thousand and \$19 thousand were received from exercise of unit option awards during the nine months ended September 30, 2011 and 2010, respectively.
- (2) The weighted average remaining contractual life for outstanding and exercisable options at September 30, 2010 was 8.3 years.
- (3) The aggregate intrinsic value of options outstanding at September 30, 2010 was \$1.1 million.
- (4) The aggregate intrinsic value of options exercisable at September 30, 2010 was \$249 thousand.
- (5) Non-cash compensation expense for the nine months ended September 30, 2011 includes incremental compensation expense of \$2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner.

### *Employee Incentive Compensation Plan and Agreement*

A wholly-owned subsidiary of the Partnership has an incentive plan (the “Cash Plan”), which allows for equity-indexed cash incentive awards to employees of the Partnership (the “Participants”). The Cash Plan is administered by a committee appointed by the CEO of the General Partner. Under the Cash Plan, cash bonus units may be awarded to Participants at the discretion of the committee. During 2009, the committee granted 375,000 bonus units (“Bonus Units”). A Bonus Unit entitles the employee to receive the cash equivalent of the then-fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. Vesting will terminate upon termination of employment with cause. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 of the then outstanding 375,000 Bonus Units agreed to exchange their Bonus Units for phantom units, during the nine months ended September 30, 2010.

At September 30, 2011, the Partnership had 25,500 outstanding Bonus Units, which will all vest within the following twelve months. The Partnership recognizes compensation expense related to these awards based upon the fair value, which is re-measured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized compensation expense related to the re-measurement of the outstanding Bonus Units of \$9 thousand and \$0.3 million during the three months

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ended September 30, 2011 and 2010, respectively, and expense of \$0.6 million during the nine months ended September 30, 2011 and a credit of \$0.5 million during the nine months ended September 30, 2010, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had \$0.6 million and \$0.8 million, at September 30, 2011 and December 31, 2010, respectively, included within accrued liabilities on its consolidated balance sheet with regard to these awards, which represents their fair value as of those dates.

### **NOTE 14 - RELATED PARTY TRANSACTIONS**

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of Atlas 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 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 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 (see Note 1). The Partnership reimbursed the General Partner and its affiliates \$0.4 million and \$0.4 million for the three months ended September 30, 2011 and 2010, respectively, and \$1.3 million and \$1.1 million for the nine months ended September 30, 2011 and 2010, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the nine months ended September 30, 2011 and 2010. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

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

### **NOTE 15 - SEGMENT INFORMATION**

On February 17, 2011, the Partnership sold its 49% interest in Laurel Mountain, which was reported as part of the Partnership's previous Appalachia segment (see Note 3). On May 11, 2011, the Partnership acquired a 20% interest in WTLPG (see Note 3). As a result of these two transactions, the Partnership realigned the reportable segments into two new segments: Gathering and Processing; and Pipeline Transportation ("Pipeline"). These reportable segments reflect the way the Partnership will manage its operations going forward. The Partnership has adjusted its segment presentation from the amounts previously presented to reflect the realignment of the segments.

The Gathering and Processing segment consists of (1) the WestOK, WestTX and Velma operations, which are comprised of natural gas gathering and processing assets servicing drilling activity in the Anadarko and Permian Basins, and which were formerly included within the previous Mid-Continent segment; (2) the natural gas gathering assets located in Tennessee, which were formerly included in the previous Appalachia segment; and (3) the revenues and gain on sale related to the Partnership's 49% interest in Laurel Mountain, which were formerly included in the previous Appalachia

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segment. Gathering and Processing revenues are primarily derived from the sale of residue gas and NGLs and gathering of natural gas.

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

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

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
<b>Three Months Ended September 30, 2011:</b>				
<b>Revenue:</b>				
Revenues - third party <sup>(1)</sup>	\$357,655	\$-	\$22,046	\$379,701
Revenues - affiliates	79	-	-	79
Total revenue and other income (loss), net	<u>357,734</u>	<u>-</u>	<u>22,046</u>	<u>379,780</u>
<b>Costs and Expenses:</b>				
Operating costs and expenses	296,615	129	-	296,744
General and administrative <sup>(1)</sup>	-	-	9,149	9,149
Other costs	-	8	-	8
Depreciation and amortization	19,471	-	-	19,471
Interest expense <sup>(1)</sup>	-	-	5,935	5,935
Total costs and expenses	<u>316,086</u>	<u>137</u>	<u>15,084</u>	<u>331,307</u>
Equity income	-	1,785	-	1,785
Net income	<u>\$41,648</u>	<u>\$1,648</u>	<u>\$6,962</u>	<u>\$50,258</u>
<b>Three Months Ended September 30, 2010<sup>(2)</sup>:</b>				
<b>Revenue:</b>				
Revenues - third party <sup>(1)</sup>	\$235,190	\$-	\$(9,213 )	\$225,977
Revenues - affiliates	141	-	-	141
Total revenue and other income (loss), net	<u>235,331</u>	<u>-</u>	<u>(9,213 )</u>	<u>226,118</u>
<b>Costs and expenses:</b>				
Operating costs and expenses	191,772	-	-	191,772
General and administrative <sup>(1)</sup>	-	-	7,578	7,578
Depreciation and amortization	18,566	-	-	18,566
Interest expense <sup>(1)</sup>	-	-	23,087	23,087
Total costs and expenses	<u>210,338</u>	<u>-</u>	<u>30,665</u>	<u>241,003</u>
Equity income	1,787	-	-	1,787
Loss on early extinguishment of debt	-	-	(4,359 )	(4,359 )
Net income (loss) from continuing operations	26,780	-	(44,237 )	(17,457 )
Income from discontinued operations	-	-	305,927	305,927
Net income	<u>\$26,780</u>	<u>\$-</u>	<u>\$261,690</u>	<u>\$288,470</u>

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	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
<b>Nine Months Ended September 30, 2011:</b>				
<b>Revenue:</b>				
Revenues - third party <sup>(1)</sup>	\$982,739	\$-	\$3,833	\$986,572
Revenues - affiliates	256	-	-	256
Total revenue and other income (loss), net	<u>982,995</u>	<u>-</u>	<u>3,833</u>	<u>986,828</u>
<b>Costs and expenses:</b>				
Operating costs and expenses	815,573	129	-	815,702
General and administrative <sup>(1)</sup>	-	-	26,821	26,821
Other costs	-	583	-	583
Depreciation and amortization	57,499	-	-	57,499
Interest expense <sup>(1)</sup>	-	-	24,525	24,525
Total costs and expenses	<u>873,072</u>	<u>712</u>	<u>51,346</u>	<u>925,130</u>
Equity income	462	2,472	-	2,934
Gain on sale of assets	255,674	-	-	255,674
Loss on early extinguishment of debt	-	-	(19,574 )	(19,574 )
Net income (loss) from continuing operations	366,059	1,760	(67,087 )	300,732
Loss from discontinued operations	-	-	(81 )	(81 )
Net income (loss)	<u>\$366,059</u>	<u>\$1,760</u>	<u>\$(67,168 )</u>	<u>\$300,651</u>
<b>Nine Months Ended September 30, 2010<sup>(2)</sup>:</b>				
<b>Revenue:</b>				
Revenues - third party <sup>(1)</sup>	\$692,052	\$-	\$(10,026 )	\$682,026
Revenues - affiliates	472	-	-	472
Total revenue and other income (loss), net	<u>692,524</u>	<u>-</u>	<u>(10,026 )</u>	<u>682,498</u>
<b>Costs and Expenses:</b>				
Operating costs and expenses	558,708	-	-	558,708
General and administrative <sup>(1)</sup>	-	-	23,521	23,521
Depreciation and amortization	55,647	-	-	55,647
Interest expense <sup>(1)</sup>	-	-	74,085	74,085
Total costs and expenses	<u>614,355</u>	<u>-</u>	<u>97,606</u>	<u>711,961</u>
Equity income	4,137	-	-	4,137
Loss on early extinguishment of debt	-	-	(4,359 )	(4,359 )
Net income (loss) from continuing operations	82,306	-	(111,991)	(29,685 )
Income from discontinued operations	-	-	320,684	320,684
Net income	<u>\$82,306</u>	<u>\$-</u>	<u>\$208,693</u>	<u>\$290,999</u>
	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2011</b>	<b>2010<sup>(2)</sup></b>	<b>2011</b>	<b>2010<sup>(2)</sup></b>
<b>Capital Expenditures:</b>				
Gathering and Processing	\$56,175	\$11,340	\$148,144	\$32,078
Pipeline	-	-	-	-
	<u>\$56,175</u>	<u>\$11,340</u>	<u>\$148,144</u>	<u>\$32,078</u>





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<b>Balance Sheet</b>	<b>September 30, 2011</b>	<b>December 31, 2010</b>
<b>Investment in joint ventures:</b>		
Gathering and Processing	\$–	\$153,358
Pipeline	86,688	–
	<u>\$86,688</u>	<u>\$153,358</u>
<b>Total assets:</b>		
Gathering and Processing	\$1,735,445	\$1,738,493
Pipeline	86,915	–
Corporate other	57,953	26,355
	<u>\$1,880,313</u>	<u>\$1,764,848</u>

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

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
<b>Natural gas and liquids:</b>				
Natural gas	\$112,909	\$72,421	\$299,566	\$226,806
NGLs	209,941	134,294	582,806	383,962
Condensate	19,070	12,526	56,268	30,895
Other	(422 )	1,237	(665 )	315
Total	<u>\$341,498</u>	<u>\$220,478</u>	<u>\$937,975</u>	<u>\$641,978</u>

- (1) The Partnership notes derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.
- (2) Restated to reflect the realignment of the segments due to the sale of Laurel Mountain and the acquisition of WTLPG (see Note 3) and to reflect the reclass of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

### **NOTE 16 - SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION**

The Partnership's 8.75% Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements as of September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 2011 and 2010 include the financial statements of Atlas Pipeline Mid-Continent WestOk, LLC ("WestOK LLC") and Atlas Pipeline Mid-Continent WestTex, LLC ("WestTX LLC"), entities in which the Partnership has 95% interests. Under the terms of the 8.75% Senior Notes and the revolving credit facility, WestOK LLC and WestTX LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership's stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership's consolidated accounts as of September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 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):

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	<u>Balance Sheets</u>		Non-		<u>Consolidated</u>
	<u>September 30, 2011</u>	<u>Parent</u>	<u>Guarantor Subsidiaries</u>	<u>Guarantor Subsidiaries</u>	
<b>Assets</b>					
Cash and cash equivalents	\$-	\$167	\$-	\$-	\$167
Accounts receivable - affiliates	211,201	52,538	-	(263,739 )	-
Other current assets	255	50,239	104,789	(1,109 )	154,174
Total current assets	211,456	102,944	104,789	(264,848 )	154,341
Property, plant and equipment, net	-	264,239	1,217,202	-	1,481,441
Intangible assets, net	-	-	109,052	-	109,052
Investment in joint venture	-	86,688	-	-	86,688
Long term portion of derivative asset	-	26,950	-	-	26,950
Long term notes receivable	-	-	1,852,928	(1,852,928)	-
Equity investments	1,459,815	2,052,644	-	(3,512,459)	-
Other assets, net	19,116	1,773	952	-	21,841
Total assets	<u>\$1,690,387</u>	<u>\$2,535,238</u>	<u>\$3,284,923</u>	<u>\$(5,630,235)</u>	<u>\$1,880,313</u>
<b>Liabilities and Equity</b>					
Accounts payable - affiliates	\$-	\$-	\$266,415	\$(263,739 )	\$2,676
Other current liabilities	5,670	42,355	135,240	-	183,265
Total current liabilities	5,670	42,355	401,655	(263,739 )	185,941
Long-term debt, less current portion	414,322	-	9,605	-	423,927
Other long-term liability	77	50	-	-	127
Equity	1,270,318	2,492,833	2,873,663	(5,366,496)	1,270,318
Total liabilities and equity	<u>\$1,690,387</u>	<u>\$2,535,238</u>	<u>\$3,284,923</u>	<u>\$(5,630,235)</u>	<u>\$1,880,313</u>
<b>December 31, 2010</b>					
<b>Assets</b>					
Cash and cash equivalents	\$-	\$164	\$-	\$-	\$164
Accounts receivable - affiliates	1,329,448	-	-	(1,329,448)	-
Other current assets	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
Long term 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
Total assets	<u>\$1,608,980</u>	<u>\$(209,578 )</u>	<u>\$3,167,092</u>	<u>\$(2,801,646)</u>	<u>\$1,764,848</u>
<b>Liabilities and Equity</b>					
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	<u>1,041,647</u>	<u>(1,440,864)</u>	<u>2,913,062</u>	<u>(1,472,198)</u>	<u>1,041,647</u>
Total liabilities and equity	<u>\$1,608,980</u>	<u>\$(209,578 )</u>	<u>\$3,167,092</u>	<u>\$(2,801,646)</u>	<u>\$1,764,848</u>

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### Statements of Operations

	<u>Parent</u>		<u>Non-Guarantor</u>		<u>Consolidated</u>
	<u>Parent</u>	<u>Subsidiaries</u>	<u>Subsidiaries</u>	<u>Adjustments</u>	
<b><u>Three Months Ended September 30, 2011</u></b>					
Total revenue and other income (loss), net	\$-	\$95,458	\$284,322	\$-	\$379,780
Total costs and expenses	(3,857 )	(81,241 )	(246,209 )	-	(331,307 )
Equity income	53,613	40,460	-	(92,288 )	1,785
Net income (loss)	<u>\$49,756</u>	<u>\$54,677</u>	<u>\$38,113</u>	<u>\$(92,288 )</u>	<u>\$50,258</u>
<b><u>Three Months Ended September 30, 2010<sup>(1)</sup></u></b>					
Total revenue and other income (loss), net	\$-	\$36,959	\$189,159	\$-	\$226,118
Total costs and expenses	(11,047 )	(67,485 )	(162,471 )	-	(241,003 )
Equity income	294,137	29,017	-	(321,367 )	1,787
Loss on early extinguishment of debt	-	(4,359 )	-	-	(4,359 )
Income (loss) from continuing operations	283,090	(5,868 )	26,688	(321,367 )	(17,457 )
Income from discontinued operations	-	305,927	-	-	305,927
Net income (loss)	<u>\$283,090</u>	<u>\$300,059</u>	<u>\$26,688</u>	<u>\$(321,367 )</u>	<u>\$288,470</u>
<b><u>Nine Months Ended September 30, 2011</u></b>					
Total revenue and other income (loss), net	\$-	\$202,637	\$784,191	\$-	\$986,828
Total costs and expenses	(19,661 )	(221,578 )	(683,891 )	-	(925,130 )
Equity income	337,728	103,357	-	(438,151 )	2,934
Gain on asset sales and other	-	255,674	-	-	255,674
Loss on early extinguishment of debt	(19,574 )	-	-	-	(19,574 )
Income (loss) from continuing operations	298,493	340,090	100,300	(438,151 )	300,732
Loss from discontinued operations	-	(81 )	-	-	(81 )
Net income (loss)	<u>\$298,493</u>	<u>\$340,009</u>	<u>\$100,300</u>	<u>\$(438,151 )</u>	<u>\$300,651</u>
<b><u>Nine Months Ended September 30, 2010<sup>(1)</sup></u></b>					
Total revenue and other income (loss), net	\$-	\$123,513	\$558,985	\$-	\$682,498
Total costs and expenses	(32,951 )	(200,806 )	(478,204 )	-	(711,961 )
Equity income	316,616	84,488	-	(396,967 )	4,137
Loss on early extinguishment of debt	-	(4,359 )	-	-	(4,359 )
Income (loss) from continuing operations	283,665	2,836	80,781	(396,967 )	(29,685 )
Income from discontinued operations	-	320,684	-	-	320,684
Net income (loss)	<u>\$283,665</u>	<u>\$323,520</u>	<u>\$80,781</u>	<u>\$(396,967 )</u>	<u>\$290,999</u>

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<u>Statements of Cash Flows</u>					
<u>Nine Months Ended September 30, 2011</u>	<u>Parent</u>	<u>Guarantor Subsidiaries</u>	<u>Non- Guarantor Subsidiaries</u>	<u>Consolidating Adjustments</u>	<u>Consolidated</u>
Net cash provided by (used in):					
Total operating activities	\$(21,998 )	\$34,831	\$164,961	\$(97,136 )	\$80,658
Continuing investing activities	268,195	292,617	(123,226 )	(271,511 )	166,075
Discontinued investing activities	–	(81 )	–	–	(81 )
Total investing activities	268,195	292,536	(123,226 )	(271,511 )	165,994
Total financing activities	(246,197)	(327,364 )	(41,735 )	368,647	(246,649 )
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

<u>Statements of Cash Flows</u>					
<u>Nine Months Ended September 30, 2010</u>					
Net cash provided by (used in):					
Continuing operating activities	\$361,840	\$15,291	\$144,031	\$(444,367 )	\$76,795
Discontinued operating activities	–	24,490	–	–	24,490
Total operating activities	361,840	39,781	144,031	(444,367 )	101,285
Continuing investing activities	370,097	861,369	(26,580 )	(1,242,603)	(37,717 )
Discontinued investing activities	–	667,605	–	–	667,605
Total investing activities	370,097	1,528,974	(26,580 )	(1,242,603)	629,888
Total financing activities	(731,937)	(1,569,610)	(117,451 )	1,686,970	(732,028 )
Net change in cash and cash equivalents	–	(855 )	–	–	(855 )
Cash and cash equivalents, beginning of period	–	1,021	–	–	1,021
Cash and cash equivalents, end of period	\$–	\$166	\$–	\$–	\$166

- (1) Restated to reflect the reclass of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

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

#### Forward-Looking Statements

When used in this Form 10-Q, the words “believes,” “anticipates,” “expects” and similar expressions are intended to identify forward-looking statements. Such statements are subject to certain risks and uncertainties more particularly described in Item 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 and with our Annual Report on Form 10-K for the year ended December 31, 2010.

#### *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; a provider of natural gas gathering services in the Appalachian Basin in the northeastern region of the United States; and a provider of NGL transportation services in the southwestern region of the United States.

Due to the sale of our 49% non-controlling interest in Laurel Mountain Midstream, LLC (“Laurel Mountain”) and our acquisition of a 20% interest in West Texas LPG Pipeline Limited Partnership (“WTLPG”) (see “- Recent Events”), we realigned the management of our business in the midstream segment of the natural gas industry into two new reportable segments: Gathering and Processing; and Pipeline Transportation.

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

Our Gathering and Processing operations, as of September 30, 2011, own, have interests in and operate five natural gas processing plants with aggregate capacity of approximately 520 MMCFD, which are connected to approximately 8,600 miles of active natural gas gathering systems located in Oklahoma, Kansas and Texas. These assets were formerly included in our previous Mid-Continent segment. In addition we own and operate approximately 70 miles of active natural gas gathering systems located in

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Tennessee, which were formerly included in our previous Appalachia segment. Our gathering systems gather gas from wells and central delivery points and deliver to natural gas processing and treating plants, as well as third-party pipelines.

Our Pipeline Transportation operations, as of September 30, 2011, own a 20% interest in WTLPG, which was acquired on May 11, 2011 (see “- Recent Events”). WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest.

### **Recent Events**

On February 17, 2011, we completed the sale to Atlas Energy Resources, LLC of our 49% non-controlling interest in Laurel Mountain 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.

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

On April 8, 2011, we redeemed all 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.

On May 11, 2011, we acquired a 20% interest in WTLPG from Buckeye Partners, L.P. for \$85.0 million. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation and is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest.

On May 27, 2011, we redeemed our 8,000 units of Class C Preferred Units for cash at the liquidation value of \$1,000 per unit, or \$8.0 million plus \$0.2 million accrued dividends. There are no longer any Class C Preferred Units outstanding (see “- Preferred Units”).

On July 8, 2011, we exercised the \$100.0 million accordion feature on our revolving credit facility to increase the capacity from \$350.0 million to \$450.0 million. The other terms of the credit agreement remain unchanged.

On July 15, 2011, we amended an operating lease for eight natural gas compressors to include a mandatory purchase of the equipment at the end of the term of the lease, thereby converting the agreement into a capital lease upon the effective date of the amendment and capitalized \$11.4 million within property, plant and equipment with an offsetting liability within debt on our consolidated balance sheets based on the minimum payments required under the lease and our incremental borrowing rate.

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On August 29, 2011, we signed long-term product sales agreements with DCP NGL Services, LLC (“DCP”), a subsidiary of DCP Midstream, LLC, to sell our NGL production from each of our processing facilities in Oklahoma and Texas. The agreements are based on Mt. Belvieu NGL pricing and each has a term of fifteen years, which will become effective at various times upon expiration of our existing NGL sales agreements.

### **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 gathered and processed;
- the contract terms with each producer; and
- the efficiency of our gathering systems and processing plants.

Revenue consists of the sale of natural gas and NGLs and the fees earned from our gathering and processing operations. Under certain agreements, we purchase natural gas from producers and move it into receipt points on our pipeline systems and then sell the natural gas and NGLs off delivery points on our systems. Under other agreements, we gather natural gas across our systems, from receipt to delivery point, without taking title to the natural gas. (See “Item 1. Notes to Consolidated Financial Statements (Unaudited) - Note 2- Revenue Recognition” for further discussion of contractual revenue arrangements).

### **Results of Operations**

The following table illustrates selected pricing and volumetric information for the periods indicated:



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	Three Months Ended September 30,			Nine Months Ended September 30,		
	2011	2010	Percent Change	2011	2010	Percent Change
<b>Pricing:</b>						
Weighted Average Market Prices:						
NGL price per gallon - Conway hub	\$1.13	\$0.85	32.9 %	\$1.11	\$0.93	19.4 %
NGL price per gallon - Mt. Belvieu hub	1.36	0.95	43.2 %	1.30	1.04	25.0 %
Natural gas sales (\$/Mcf):						
Velma	4.02	4.03	(0.2 )%	4.04	4.35	(7.1 )%
WestOK	4.04	4.01	0.7 %	4.05	4.35	(6.9 )%
WestTX	4.05	3.99	1.5 %	4.04	4.30	(6.0 )%
Weighted Average	4.04	4.01	0.7 %	4.04	4.33	(6.7 )%
NGL sales (\$/gallon):						
Velma	1.16	0.80	45.0 %	1.12	0.87	28.7 %
WestOK	1.17	0.91	28.6 %	1.13	0.92	22.8 %
WestTX	1.42	0.94	51.1 %	1.32	1.00	32.0 %
Weighted Average	1.27	0.90	41.1 %	1.21	0.96	26.0 %
Condensate sales (\$/barrel):						
Velma	88.54	74.92	18.2 %	94.39	76.19	23.9 %
WestOK	81.23	68.73	18.2 %	86.75	71.33	21.6 %
WestTX	87.68	74.82	17.2 %	92.77	74.06	25.3 %
Weighted Average	85.77	73.55	16.6 %	90.91	73.68	23.4 %
<b>Operating data:</b>						
Velma system:						
Gathered gas volume (MCFD)	111,777	90,377	23.7 %	101,593	81,107	25.3 %
Processed gas volume (MCFD)	104,930	84,255	24.5 %	95,643	75,531	26.6 %
Residue Gas volume (MCFD)	87,099	68,713	26.8 %	78,462	61,559	27.5 %
NGL volume (BPD)	12,198	10,231	19.2 %	11,219	8,749	28.2 %
Condensate volume (BPD)	346	369	(6.2 )%	439	410	7.1 %
WestOK system:						
Gathered gas volume (MCFD)	277,794	225,395	23.2 %	260,863	223,511	16.7 %
Processed gas volume (MCFD)	263,654	211,533	24.6 %	247,259	197,197	25.4 %
Residue Gas volume (MCFD)	242,744	187,024	29.8 %	224,158	177,245	26.5 %
NGL volume (BPD)	13,392	11,561	15.8 %	13,395	11,785	13.7 %
Condensate volume (BPD)	786	599	31.2 %	842	661	27.4 %
WestTX system <sup>(1)</sup> :						
Gathered gas volume (MCFD)	224,412	188,960	18.8 %	205,089	175,985	16.5 %
Processed gas volume (MCFD)	198,068	170,988	15.8 %	188,292	161,474	16.6 %
Residue Gas volume (MCFD)	136,594	109,167	25.1 %	128,584	104,742	22.8 %
NGL volume (BPD)	27,387	28,557	(4.1 )%	28,003	26,533	5.5 %
Condensate volume (BPD)	2,257	1,867	20.9 %	1,707	1,353	26.2 %
Tennessee system:						
Average throughput volumes (MCFD)	7,493	9,142	(18.0 )%	7,747	8,767	(11.6 )%

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

*Three Months Ended September 30, 2011 Compared to Three Months Ended September 30, 2010*

*Revenue.* The following table details the revenue variances between the three months ended September 30, 2011 and 2010 (in thousands):

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	<b>Three Months Ended</b>			<b>Percent</b>
	<b>September 30,</b>			
	<b>2011</b>	<b>2010</b>	<b>Variance</b>	<b>Change</b>
<i>Revenues:</i>				
Natural gas and liquids	\$341,498	\$220,478	\$121,020	54.9 %
Transportation, processing and other fees	11,691	9,951	1,740	17.5 %
Other income (loss), net	26,591	(4,311 )	30,902	716.8%
<b>Total Revenues</b>	<b>\$379,780</b>	<b>\$226,118</b>	<b>\$153,662</b>	<b>68.0 %</b>

Natural gas and liquids revenue for the three months ended September 30, 2011 increased primarily due to a favorable price change as a result of higher realized commodity prices combined with higher production volumes.

Volumes on the Velma system increased for the three months ended September 30, 2011 when compared to the prior year period primarily due to new production gathered on the Madill-to-Velma gas gathering pipeline. Volumes on the WestOK system increased for the three months ended September 30, 2011 compared to the prior year due to the completion of an expansion into Kansas in 2010. WestTX system gathering and processing volumes for the three months ended September 30, 2011 increased when compared to the prior year period due to increased volumes from Pioneer as a result of their continued drilling program. WestTX system NGL volumes were impacted by plant maintenance and liquid allocation on the system, resulting in the NGL volumes having a slight decrease in comparison to the prior year period.

Transportation, processing and other fees for the three months ended September 30, 2011 increased primarily due to increased processing fee revenue on the Velma system related to the increased volumes processed through the system.

Other income (loss), net, including the impact of certain gains and losses recognized on derivatives had a favorable variance for the three months ended September 30, 2011 due primarily to \$32.8 million favorable non-cash mark-to-market adjustments on commodity-based derivatives, partially offset by \$1.8 million higher net cash settlements 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 variances between the three months ended September 30, 2011 and 2010 (in thousands):

	<b>Three Months Ended</b>			<b>Percent</b>
	<b>September 30,</b>			
	<b>2011</b>	<b>2010</b>	<b>Variance</b>	<b>Change</b>
<i>Costs and Expenses:</i>				
Natural gas and liquids	\$282,391	\$178,920	\$103,471	57.8 %
Plant operating	14,085	12,552	1,533	12.2 %
Transportation and compression	268	300	(32 )	(10.7)%
General and administrative	9,149	7,578	1,571	20.7 %
Other costs	8	-	8	100 %
Depreciation and amortization	19,471	18,566	905	4.9 %
Interest expense	5,935	23,087	(17,152)	(74.3)%
<b>Total Costs and Expenses</b>	<b>\$331,307</b>	<b>\$241,003</b>	<b>\$90,304</b>	<b>37.5 %</b>

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Natural gas and liquids cost of goods sold for the three months ended September 30, 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.”

Plant operating expense for the three months ended September 30, 2011 increased primarily due to increased processed volumes in comparison to the prior year period, as discussed above in “Revenues.”

Transportation and compression expenses for the three months ended September 30, 2011 decreased due to lower throughput volumes on the Tennessee gathering system.

General and administrative expense, including amounts reimbursed to affiliates, increased for the three months ended September 30, 2011 primarily due to a \$1.8 million increase in salaries and wages.

Interest expense for the three months ended September 30, 2011 decreased primarily due to a \$6.6 million decrease in interest expense associated with our term loan retired in the prior year; a \$5.6 million decrease in interest expense associated with the 8.125% Senior Notes; a \$3.2 million decrease in interest expense associated with our revolving credit facility and a \$1.5 million increase in capitalized interest. 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 borrowings in September 2010 with proceeds from the sale of Elk City. The lower interest expense on our 8.125% Senior Notes is due to the redemption of the 8.125% Senior Notes in April 2011, with proceeds from the sale of our 49% non-controlling interest in Laurel Mountain (see “- Recent Events”). The increased capitalized interest is due to the increased capital expenditures in the current period (see “- Capital Requirements”)

*Other income items.* The following table details the changes between the three months ended September 30, 2011 and 2010 for other income items (in thousands):

	Three Months Ended			Percent Change
	September 30,			
	2011	2010	Variance	
Equity income in joint ventures	\$1,785	\$1,787	\$(2 )	(0.1 )%
Loss on early extinguishment of debt	–	(4,359 )	4,359	100.0 %
Income from discontinued operations	–	305,927	(305,927)	(100.0)%
Income attributable to non-controlling interests	(1,760)	(1,076 )	(684 )	(63.6 )%

Equity income in joint ventures for the current year period represents our ownership interest in the net income of WTLPG, which we purchased on May 11, 2011 (see “- Recent Events”). Equity income in joint ventures for the prior year period represents our ownership interest in the net income of Laurel Mountain, which we sold on February 17, 2011 (see “- Recent Events”).

Loss on early extinguishment of debt for the three months ended September 30, 2010 represents the accelerated amortization of debt expense related to the early retirement of our term loan with proceeds from the sale of Elk City.

Income from discontinued operations for the three months ended September 30, 2010 represents a \$311.5 million gain on sale associated with the Elk City system, which was sold on September 16, 2010, offset by a \$5.6 million loss related to the income of Elk City.

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

### *Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010*

*Revenue.* The following table details the revenue changes between the nine months ended September 30, 2011 and 2010 (in thousands):

	<u>Nine Months Ended</u> <u>September 30,</u>			<u>Percent</u>
	<u>2011</u>	<u>2010</u>	<u>Change</u>	<u>Change</u>
<i>Revenues:</i>				
Natural gas and liquids	\$937,975	\$641,978	\$295,997	46.1 %
Transportation, processing and other fees	31,536	29,944	1,592	5.3 %
Other income (loss), net	17,317	10,576	6,741	63.7 %
<i>Total Revenues</i>	<u>\$986,828</u>	<u>\$682,498</u>	<u>\$304,330</u>	<u>44.6 %</u>

Natural gas and liquids revenue for the nine months ended September 30, 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 nine months ended September 30, 2011 when compared to the prior year period primarily due to new production gathered on the Madill-to-Velma gas gathering pipeline. Volume on the WestOK system increased for the nine months ended September 30, 2011 compared to the prior year due to the completion of an expansion into Kansas in June 2010. WestTX system volumes for the nine months ended September 30, 2011 increased when compared to the prior year period due to increased volumes from Pioneer as a result of their continued drilling program.

Other income (loss), net, including the impact of certain gains and losses recognized on derivatives had a favorable variance for the nine months ended September 30, 2011 due primarily to \$13.7 million favorable 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 nine months ended September 30, 2011 and 2010 (in thousands):

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	Nine Months Ended			Percent Change
	September 30,			
	2011	2010	Change	
<i>Costs and Expenses:</i>				
Natural gas and liquids	\$774,859	\$521,495	\$253,364	48.6 %
Plant operating	40,240	36,492	3,748	10.3 %
Transportation and compression	603	721	(118 )	(16.4 )%
General and administrative	26,821	23,521	3,300	14.0 %
Other costs	583	–	583	100.0%
Depreciation and amortization	57,499	55,647	1,852	3.3 %
Interest expense	24,525	74,085	(49,560)	(66.9 )%
<i>Total Costs and Expenses</i>	<u>\$925,130</u>	<u>\$711,961</u>	<u>\$213,169</u>	<u>29.9 %</u>

Natural gas and liquids cost of goods sold for the nine months ended September 30, 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.”

Plant operating expense for the nine months ended September 30, 2011 increased primarily due to increased processed volumes in comparison to the prior year period, as discussed above in “Revenues.”

Transportation and compression expenses for the nine months ended September 30, 2011 decreased due to lower throughput volumes on the Tennessee gathering system.

General and administrative expense, including amounts reimbursed to affiliates, increased for the nine months ended September 30, 2011 mainly due to an increase in net salaries and wages of \$2.9 million.

Other costs for the nine months ended September 30, 2011 are associated with the acquisition of WTLPG in May 2011 (see “- Recent Events”).

Interest expense for the nine months ended September 30, 2011 decreased primarily due to a \$21.1 million decrease in interest expense associated with our term loan retired during the prior year; a \$12.2 million decrease in interest expense associated with our revolving credit facility; and a \$10.8 million decrease in interest expense associated with the 8.125% Senior Notes. 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 borrowings in September 2010 with proceeds from the sale of Elk City. The lower interest expense on our 8.125% Senior Notes is due to the redemption of the 8.125% Senior Notes in April 2011, with proceeds from the sale of our 49% non-controlling interest in Laurel Mountain (see “- Recent Events”).

*Other income items.* The following table details the changes between the nine months ended September 30, 2011 and 2010 for other income items (in thousands):

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	Nine Months Ended			Percent Change
	September 30,			
	2011	2010	Change	
Equity income in joint ventures	\$2,934	\$4,137	\$(1,203 )	(29.1 )%
Gain on asset sales and other	255,674	–	255,674	100.0 %
Loss on early extinguishment of debt	(19,574)	(4,359 )	(15,215 )	(349.0)%
Income (loss) from discontinued operations	(81 )	320,684	(320,765)	(100.0)%
Income attributable to non-controlling interests	(4,492 )	(3,338 )	(1,154 )	(34.6 )%

Equity income in joint ventures decreased for the nine months ended September 30, 2011, primarily due to the sale of our ownership interest in Laurel Mountain on February 17, 2011, resulting in \$3.7 million lower equity earnings from Laurel Mountain (see “– Recent Events”); partially offset by \$2.5 million equity earnings generated in the current period from our 20% ownership interest in WTPLG, which was purchased in May 2011 (see “– Recent Events”).

Gain on asset sales and other for the nine months ended September 30, 2011 includes amounts associated with the sale of our 49% interest in Laurel Mountain on February 17, 2011 (see “– Recent Events”).

Loss on early extinguishment of debt for the nine months ended September 30, 2011 represents the premium paid for the redemption of the 8.125% Senior Notes and the recognition of deferred finance costs related to the redemption (see “– Recent Events”). Loss on early extinguishment of debt for the nine months ended September 30, 2010 represents the accelerated amortization of debt expense related to the early retirement of our term loan with proceeds from the sale of Elk City.

Income from discontinued operations for the nine months ended September 30, 2010 represents a \$311.5 million gain on sale associated with the Elk City system, which was sold on September 16, 2010, and \$9.2 million net income related to the operations of Elk City.

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

## **Liquidity and Capital Resources**

### *General*

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

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through the retention of cash and

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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 September 30, 2011, we had \$198.5 million outstanding borrowings under our \$450.0 million senior secured revolving credit facility and \$1.1 million of outstanding letters of credit, which are not reflected as borrowings on our consolidated balance sheets, with \$250.4 million of remaining committed capacity under the revolving credit facility, (see “- Revolving Credit Facility”). We were in compliance with the credit facility’s covenants at September 30, 2011. We had a working capital deficit of \$31.6 million at September 30, 2011 compared with a \$36.6 million working capital deficit at December 31, 2010. We believe we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve-month period. However, we are subject to business, operational and other risks that could adversely affect our cash 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 revolving credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain additional capital will be available to the extent required and on acceptable terms.

### *Cash Flows - Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010*

The following table details the cash flow changes between the nine months ended September 30, 2011 and 2010 (in thousands):

	Nine Months Ended		Variance	Percent Change
	September 30,			
	2011	2010		
Net cash provided by (used in):				
Operating activities	\$80,658	\$101,285	\$(20,627 )	(20.4 )%
Investing activities	165,994	629,888	(463,894)	(73.7 )%
Financing activities	(246,649)	(732,028)	485,379	66.3 %
Net change in cash and cash equivalents	\$3	\$(855 )	\$858	100.4%

Net cash provided by operating activities for the nine months ended September 30, 2011 decreased primarily due to a \$41.9 million decrease in the change in working capital and a \$24.5 million decrease in cash provided by discontinued operations; offset by a \$45.8 million increase in net earnings from continuing operations excluding non-cash charges. The decrease in the change in working capital is primarily due to a \$58.6 million increase in receivables during the current year period related to higher revenues. The increase in net earnings from continuing operations excluding non-cash charges is primarily due to increased revenues from the sale of natural gas and NGLs (see “- Results of Operations”).

Net cash provided by investing activities for the nine months ended September 30, 2011 decreased mainly as a result of net proceeds of \$674.4 million received from the sale of the Elk City system in the prior period; a \$117.0 million increase in capital expenditures in the current year period



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compared to the prior year period (see further discussion of capital expenditures under “- Capital Requirements”); and \$85.0 million paid for the acquisition of WTLPG (see “- Recent Events”); partially offset by \$411.5 million received from the sale of our 49% interest in Laurel Mountain (see “- Recent Events”).

Net cash used in financing activities for the nine months ended September 30, 2011 decreased mainly due to a \$433.5 million repayment of our term loan in the prior period and a \$314.0 million reduction in borrowings on our revolving credit facility in the prior period; partially offset by \$293.9 million paid for the redemption of the 8.125% Senior Notes and a portion of the 8.75% Senior Notes in the current period. The proceeds from the sale of Elk City were utilized in the retirement of the term loan and the reduction of borrowings on the revolving credit facility in the prior year period. The proceeds from the sale of Laurel Mountain were utilized in the redemption of the Senior Notes in the current year period (see “- Recent Events”).

### **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):

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Maintenance capital expenditures	\$4,980	\$2,595	\$13,451	\$6,478
Expansion capital expenditures	51,195	8,745	134,693	25,600
<b>Total</b>	<b>\$56,175</b>	<b>\$11,340</b>	<b>\$148,144</b>	<b>\$32,078</b>

Expansion capital expenditures increased for the three and nine months ended September 30, 2011 primarily due to major processing facility expansions, compressor upgrades and pipeline projects. The increase in maintenance capital expenditures for the three and nine months ended September 30, 2011 when compared with the prior year period is due to expanded processing and gathering facilities. As of September 30, 2011, we have approved additional expenditures of approximately \$194.7 million on processing facility expansions; pipeline extensions; compressor station upgrades; and maintenance. We expect to fund these projects through operating cash flow and borrowings under our existing revolving credit facility.

### **Partnership Distributions**

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and our General Partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all our cash

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receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments.

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

Available cash is initially distributed 98% to our common limited partners and 2% to our General Partner. These distribution percentages are modified to provide for incentive distributions to be paid to our General Partner if quarterly distributions to common limited partners exceed specified targets. Incentive distributions are generally defined as all cash distributions paid to our General Partner that are in excess of 2% of the aggregate amount of cash being distributed. Our General Partner, holder of all our incentive distribution rights, has agreed to allocate up to \$3.75 million of its incentive distribution rights per quarter back to us after the General Partner receives the initial \$7.0 million of incentive distribution rights per quarter. Incentive distributions of \$0.4 million were paid during the three and nine months ended September 30, 2011. No incentive distributions were paid during the nine months ended September 30, 2010.

### **Off Balance Sheet Arrangements**

As of September 30, 2011, our off balance sheet arrangements include our letters of credit, issued under the provisions of our revolving credit facility, totaling \$1.1 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.

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

### **Preferred Units**

On June 30, 2010, we sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the "Class C Preferred Units") to Atlas Energy, Inc. for cash consideration of \$1,000 per Class C Preferred Unit, for total proceeds of \$8.0 million.

The Class C Preferred Units received distributions of 12% per annum, paid quarterly on the same date as the distribution payment date for our common units. The record date for the determination of holders entitled to receive distributions was the same as the record date for determination of common unit holders entitled to receive quarterly distributions. We had the right to redeem some or all of the Class C Preferred Units for an amount equal to the face value of the Class C Preferred Units being redeemed plus all accrued but unpaid dividends.

On May 27, 2011, we redeemed the 8,000 Class C Preferred units for cash, at the liquidation value of \$1,000 per unit, or \$8.0 million, plus \$0.2 million, representing the accrued dividends on the 8,000 Class C Preferred Units prior to our redemption. There are no Class C Preferred Units outstanding at September 30, 2011.

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### **Revolving Credit Facility**

At September 30, 2011, we had a \$450.0 million senior secured revolving credit facility with a syndicate of banks, which matures in December 2015. On July 8, 2011, the revolving credit facility was increased from \$350.0 million to \$450.0 million. 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 weighted average interest rate for borrowings on the revolving credit facility, at September 30, 2011, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$1.1 million was outstanding at September 30, 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 our property and that of our subsidiaries, except for the assets owned by the WestOK and WestTX joint ventures. Borrowings are also secured by the guaranty of each of our consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including covenants to maintain specified financial ratios, restrictions on our ability to incur additional indebtedness; make certain acquisitions, loans or investments; make distribution payments to our unitholders if an event of default exists; or enter into a merger or sale of assets, including the sale or transfer of interests in our subsidiaries. We are also unable to borrow under our revolving credit facility to pay distributions of available cash to unitholders because such borrowings would not constitute “working capital borrowings” pursuant to our partnership agreement.

The events 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 September 30, 2011, we were in compliance with all covenants under the revolving credit facility.

### **Senior Notes**

At September 30, 2011, we had \$215.8 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 (“8.75% Senior Notes”). Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% Senior Notes are subject to repurchase by us at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if we do not reinvest the net proceeds within 360 days. The 8.75% Senior Notes are junior in right of payment to our secured debt, including our obligations under our revolving credit facility.

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

The indenture governing the 8.75% Senior Notes contains covenants, including limitations of our ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all our assets. We were in compliance with these covenants as of September 30, 2011.

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On April 8, 2011, we redeemed all the 8.125% senior unsecured notes due on December 15, 2015 (“8.125% Senior Notes”). The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. We paid \$293.7 million to redeem the \$275.5 million principal plus \$11.2 million premium and \$7.0 million accrued interest. There are no 8.125% Senior Notes outstanding at September 30, 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 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 September 30, 2011.

### *Recently Issued Accounting Standards*

See “Item 1. Notes to Consolidated Financial Statements (Unaudited) - Note 2 - Recently Issued Accounting Standards” for information regarding recent accounting pronouncements.

## **ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

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

### **General**

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative instruments. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on September 30, 2011. Only the potential impact of hypothetical assumptions is analyzed. The analysis does not consider other possible effects that could impact our business.

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

*Interest Rate Risk.* At September 30, 2011, we had a \$450.0 million senior secured revolving credit facility with \$198.5 million 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 weighted average interest rate for the revolving credit facility borrowings was 3.2% at September 30, 2011. Based upon the outstanding borrowings on the senior secured revolving credit facility and holding all other variables constant, a 100 basis-point, or 1%, change in interest rates would change our annual interest expense by approximately \$2.0 million.

*Commodity Price Risk.* We are exposed to commodity prices as a result of being paid for certain services in the form of natural gas, NGLs and condensate rather than cash. For gathering services, we receive fees or commodities from the producers to bring the raw natural gas from the wellhead to the processing plant. For processing services, we either receive fees or commodities as payment for these services, based on the type of contractual agreement. We use a number of different derivative instruments in connection with our commodity price risk management activities. We enter into financial swap and option instruments to hedge our forecasted natural gas, NGLs and condensate sales against the variability in expected future cash flows attributable to changes in market prices. Swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying natural gas, NGLs and condensate are sold. Under swap agreements, we receive a fixed price and remit a floating price based on certain indices for the relevant contract period. Commodity-based option instruments are contractual agreements that grant the right to receive the difference between a fixed price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. See "Item 1. Notes to Consolidated Financial Statements (Unaudited) - Note 9" for further discussion of our derivative instruments. Average estimated market prices for NGLs, natural gas and condensate, based upon twelve-month forward price curves as of October 3, 2011, are \$1.23 per gallon, \$4.09 per million BTU and \$78.92 per barrel, respectively. A 10% change in these prices would change our forecasted gross margin for the twelve-month period ended September 30, 2012 by approximately \$16.3 million.

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### **ITEM 4. CONTROLS AND PROCEDURES**

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

Under the supervision of our General Partner' s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our General Partner' s Chief Executive Officer and Chief Financial Officer concluded that as of September 30, 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 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 5. OTHER INFORMATION**

In connection with the previously-announced appointment of Robert W. “Trey” Karlovich, III as our Chief Financial Officer, on November 4, 2011, the Compensation Committee of Atlas Energy, L.P. (the “Company”) the parent of our General Partner, agreed to provide Mr. Karlovich with: (i) an annual base salary of \$275,000; and (ii) a one-time equity award of 40,000 phantom units (subject to annual vesting ratably over a period of four (4) years beginning on the first anniversary of the award). Any and all annual bonuses to be paid to Mr. Karlovich will be discretionary.

On November 4, 2011, Company entered into an employment agreement with Eugene N. Dubay. Under the agreement, Mr. Dubay has the title of Senior Vice-President of the Midstream Operations division of Atlas Energy GP, LLC, the general partner of the Company. The agreement has an effective date of November 4, 2011 and has an initial term of two years, which automatically renews for successive one-year terms unless earlier terminated pursuant to the termination provisions of the agreement.

The agreement provides for an initial annual base salary of \$500,000, and Mr. Dubay is entitled to participate in any short-term and long-term incentive programs and health and welfare plans of the Company and receive perquisites and reimbursement of business expenses, in each case as provided by the Company for its senior executives generally.

The agreement provides the following benefits in the event of a termination of Mr. Dubay’s employment:

Upon a termination by the Company for cause or by Mr. Dubay without good reason, he is entitled to receive payment of accrued but unpaid base salary and (to the extent required to be paid under Company policy) amounts of accrued but unpaid vacation, in each case through the date of termination (together, the “Accrued Obligations”).

Upon a termination of employment due to death or disability, all equity awards held by Mr. Dubay accelerate and vest in full upon such termination (“Acceleration of Equity Vesting”), and Mr. Dubay’s estate is entitled to receive, in addition to payment of all Accrued Obligations, a pro-rata amount in respect of the bonus granted to him for the fiscal year in which his termination occurs in an amount equal to the bonus earned by him for the prior fiscal year multiplied by a fraction, the numerator of which is the number of days in the fiscal year in which his termination occurs through the date of termination, and the denominator of which is the total number of days in such fiscal year (the “Pro-Rata Bonus”).

Upon a termination of employment by the Company without cause (which, for purposes of the “Acceleration of Equity Vesting” (as defined below), includes a non-renewal of the agreement) or by Mr. Dubay for good reason, he is entitled to either:

if he does not timely execute (or revokes) a release of claims against the Company, payment of the Accrued Obligations; or

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in addition to payment of the Accrued Obligations, if he timely executes and does not revoke a release of claims against the Company:

monthly cash severance installments each in an amount equal to one-twelfth of the sum of his then-current annual base salary and the annual bonus earned by him in respect of the fiscal year preceding the fiscal year in which his termination of employment occurs, payable for the then-remaining portion of the employment term (taking into account any applicable renewal term) assuming his termination had not occurred,

healthcare continuation at active employee rates for the then-remaining portion of the employment term (taking into account any applicable renewal term) assuming his termination had not occurred,

a prorated amount in respect of the bonus granted to him in respect of the fiscal year in which his termination of employment occurs based on actual performance for such year, calculated as the product of (x) the amount which would have been earned in respect of the award based on actual performance measured at the end of such fiscal year and (y) a fraction, the numerator of which is the number of days in such fiscal year through the date of termination, and the denominator of which is the total number of days in such fiscal year, paid in a lump sum in cash on the date payment would otherwise be made had he remained employed by the Company, and

Acceleration of Equity Vesting.

In connection with a change of control of the Company, any “excess parachute payments” (within the meaning of Section 280G of the Internal Revenue Code) otherwise payable to Mr. Dubai will be reduced such that the total payments to him which are subject to Section 280G are no greater than the Section 280G “safe harbor amount” if he would be in a better after-tax position as a result of such reduction.

The terms and conditions of the employment agreement for Mr. Dubai summarized above are qualified in their entirety by reference to the terms and conditions of the employment agreement itself, which is filed herewith as Exhibit 10.18.



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### ITEM 6. EXHIBITS

<u>Exhibit</u> <u>No.</u>	<u>Description</u>
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. <sup>(12)</sup>
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. <sup>(13)</sup>
3.1	Certificate of Limited Partnership <sup>(1)</sup>
3.2(a)	Second Amended and Restated Agreement of Limited Partnership <sup>(2)</sup>
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership <sup>(3)</sup>
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership <sup>(4)</sup>
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership <sup>(5)</sup>
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership <sup>(6)</sup>
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership <sup>(8)</sup>
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership <sup>(9)</sup>
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership <sup>(14)</sup>
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership <sup>(15)</sup>
4.1	Common unit certificate <sup>(1)</sup>
4.2	8 3/4% Senior Notes Indenture dated June 27, 2008 <sup>(7)</sup>
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 <sup>(16)</sup>
10.1(a)	Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011 <sup>(22)</sup>
10.1(b)	Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011 <sup>(23)</sup>
10.2	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P. <sup>(14)</sup>
10.3	Long-Term Incentive Plan <sup>(21)</sup>
10.4	Amended and Restated 2010 Long-Term Incentive Plan <sup>(22)</sup>
10.5	Form of Grant of Phantom Units in Exchange for Bonus Units <sup>(17)</sup>
10.6	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter <sup>(18)</sup>
10.7	Form of Grant of Phantom Units to Non-Employee Managers <sup>(19)</sup>
10.8	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan <sup>(21)</sup>
10.9	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement <sup>(21)</sup>
10.10	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay <sup>(10)</sup>
10.11	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras <sup>(11)</sup>

- 10.12 Phantom Unit Grant Agreement between Atlas Pipeline Mid-Continent, LLC and Eric Kalamaras, dated September 14, 2009<sup>(11)</sup>
- 10.13 Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010<sup>(13)</sup>
- 10.14 Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010<sup>(20)</sup>
- 10.15 Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010<sup>(20)</sup>

- 10.16 Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011<sup>(24)</sup>
- 10.17 Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011<sup>(24)</sup>
- 10.18 Employment Agreement between Atlas Energy, L.P. and Eugene N. Dubay dated as of November 4, 2011
- 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

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<u>Exhibit</u>	
<u>No.</u>	<u>Description</u>
32.2	Section 1350 Certification
101.INS	XBRL Instance Document <sup>(25)</sup>
101.SCH	XBRL Schema Document <sup>(25)</sup>
101.CAL	XBRL Calculation Linkbase Document <sup>(25)</sup>
101.LAB	XBRL Label Linkbase Document <sup>(25)</sup>
101.PRE	XBRL Presentation Linkbase Document <sup>(25)</sup>
101.DEF	XBRL Definition Linkbase Document <sup>(25)</sup>

- (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 April 3, 2009.
- (10) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2009.
- (11) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2009.
- (12) Previously filed as an exhibit to current report on Form 8-K on July 29, 2010.
- (13) Previously filed as an exhibit to current report on Form 8-K on November 12, 2010.
- (14) Previously filed as an exhibit to current report on Form 8-K on April 2, 2010.
- (15) Previously filed as an exhibit to current report on Form 8-K on July 7, 2010.
- (16) Previously filed as an exhibit to current report on Form 8-K on December 23, 2010.
- (17) Previously filed as an exhibit to current report on Form 8-K filed on June 17, 2010.
- (18) Previously filed as an exhibit to current report on Form 8-K filed on June 23, 2010.
- (19) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended September 30, 2010.
- (20) Previously filed as an exhibit to Atlas Energy, Inc.' s current report on Form 8-K filed on November 12, 2010.
- (21) Previously filed as an exhibit to annual report on Form 10-K filed for the year ended December 31, 2009.
- (22) Previously filed as an exhibit to quarterly report on Form 10-Q for the quarter ended March 31, 2011.
- (23) Previously filed as an exhibit to current report on Form 8-K filed on July 11, 2011.
- (24) Previously filed as an exhibit to Atlas Energy, L.P.' s quarterly report on Form 10-Q for the quarter ended March 31, 2011.
- (25) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed."

**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: November 7, 2011

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

Date: November 7, 2011

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

**LETTERHEAD OF  
ATLAS ENERGY, L.P.**

November 4, 2011

Mr. Eugene N. Dubay

**Re: Summary of Employment Terms**

Dear Gene:

This letter (the "Agreement") will summarize the arrangements that we have agreed to regarding your employment by Atlas Energy, L.P. ("ATLS"). The general terms and conditions of your employment are as follows:

1. **Titles, Positions and Location**. You will serve as a Senior Vice-President of the Midstream Operations division of Atlas Energy GP, LLC, the general partner of ATLS, and your principal day-to-day responsibilities will be as President and Chief Executive Officer of Atlas Pipeline Partners GP, LLC, the general partner of Atlas Pipeline Partners, L.P. ("APL"), and as President and Chief Executive Officer of Atlas Pipeline Mid-Continent, LLC ("Atlas Mid-Continent" and, collectively with ATLS and APL, the "Company") (the "Position"). You will be principally based at the Company's offices in Philadelphia, Pennsylvania. You will visit locations of the Company as is appropriate and necessary to carry out your duties and responsibilities with respect to the Position.

2. **Services**. You will serve the Company and its affiliates diligently, competently, and to the best of your ability during the Employment Term (defined below). You will devote substantially all of your working time and attention to the business of the Company and its affiliates, and you will not undertake any other duties which conflict with your responsibilities to the Company and its affiliates. The Company shall provide you with sufficient support, capital and personnel to assist you in performing and discharging your duties. You shall report to the Chief Executive Officer of ATLS (currently Edward E. Cohen) and, as applicable, to the boards of directors of APL and ATLS (together, the "Boards"). You will render such services as may reasonably be required of you to accomplish the business purposes of the Company.

3. **Employment Term**. The term of your employment shall commence as of November 4, 2011 (the "Employment Effective Date") and shall continue for a period of two (2) years thereafter (the "Initial Employment Term"). After the Initial Employment Term, your employment shall automatically renew for a one (1)-year renewal term and for successive one (1)-year renewal terms at the end of each such one (1)-year renewal term (each such one-year renewal term, a "Renewal Term"), unless ATLS delivers notice, not less than sixty (60) days

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prior to the end of the Initial Employment Term or Renewal Term then in effect, as the case may be (such date, the “Renewal Date”), of its intention not to renew your employment. The period commencing on the Employment Effective Date and ending on the date on which the term of your employment under this Agreement shall terminate is hereinafter referred to as the “Employment Term.”

4. **Compensation.** Your compensation shall be as follows:

(a) **Base Salary.** You shall receive an annual base salary (“Annual Base Salary”) of Five Hundred Thousand Dollars (\$500,000). The Annual Base Salary shall be payable in accordance with ATLS’ s regular payroll practices for its senior executives, as in effect from time to time.

(b) **Bonus.** You will be eligible to be considered for bonus compensation. Such bonus compensation will be based upon reasonable criteria, including performance criteria, as the Board of Directors of ATLS shall reasonably determine. Notwithstanding anything to the contrary in the incentive compensation plan, program or arrangement pursuant to which a bonus is payable, any annual bonus that you shall become entitled to receive hereunder shall be deemed earned as of December 31 of the calendar year in respect of which such annual bonus opportunity is awarded and shall be paid on or before March 15 of the following calendar year.

(c) **Equity-Based Compensation.** You shall be eligible to receive incentive equity-based compensation in the form of options to purchase units, grants of restricted units and/or other forms of equity-based compensation in APL and/or ATLS as shall be determined by the Boards. Such incentive equity-based compensation shall be subject to such restrictions and vesting as is provided under the equity compensation plans of APL and ATLS, as applicable.

(d) **Benefits.** You shall be entitled to receive the following employment-related benefits:

(i) **Participation in Benefit Plans.** (1) you shall be entitled to participate in all applicable incentive, savings, and retirement plans, practices, policies, and programs of ATLS to the extent they are generally available to other senior officers, directors or executives of ATLS, and (2) you and/or your family, as the case may be, shall be eligible for participation in, and shall receive all benefits under, all applicable welfare benefit plans, practices, policies, and programs provided by ATLS, including, without limitation, medical, prescription, dental, disability, sickness benefits, employee life insurance, accidental death, and travel insurance plans and programs, to the same extent as other senior officers, directors or executives of ATLS.

(ii) **Expenses.** ATLS shall pay, or reimburse you for, all reasonable and necessary expenses incurred in carrying out your duties under this Agreement in accordance with Company policy.

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**5. Confidential Information; No Solicitation; Non-Competition.**

(a) All confidential information or trade secrets which you may obtain relating to the business of the Company and its affiliates shall not be used by you or published, disclosed, or made accessible by you to any other person, firm, or corporation except in connection with the business, and for the benefit, of the Company and its affiliates. You shall not, until two (2) years after your employment with the Company has terminated, for yourself or on behalf of any other person, firm, partnership, corporation, or other entity, directly or indirectly solicit or hire, or attempt to solicit or hire, any employee of the Company or its affiliates (or any person employed by the Company or its affiliates within the six (6)-month period prior to such solicitation or hire or attempt to solicit or hire) away from the Company or its affiliates.

(b) In the event that your employment is terminated by ATLS for Cause, or is terminated by you for any reason other than for Good Reason (each as defined in Section 6 hereof), then you shall not, until eighteen (18) months after the termination of your employment, for whatever reason, for yourself or on behalf of any other person, firm, partnership, corporation, or other entity, directly or indirectly engage in any natural gas pipeline and/or processing business in the continental United States. For purposes of this clause 5(b), "to engage" shall include your acting as an owner (of more than 5%), employee, director or officer of an entity so engaged.

(c) You acknowledge that the restrictions contained in this Section 5 are, in view of the nature of the business of the Company, reasonable and necessary to protect the legitimate interests of the Company, and that any violation of any provision of this Section will result in irreparable injury to the Company. You also acknowledge that in the event of any such violation, the Company shall be entitled to preliminary and permanent injunctive relief, without the necessity of proving actual damages or posting a bond, and to an equitable accounting of all earnings, profits and other benefits arising from any such violation, which rights shall be cumulative and in addition to any other rights or remedies to which the Company may be entitled. You agree that in the event of any such violation, an action may be commenced by the Company for any such preliminary and permanent injunctive relief and other equitable relief in any federal or state court of competent jurisdiction sitting in Pennsylvania or in any other court of competent jurisdiction. You hereby waive, to the fullest extent permitted by law, any objection that you may now or hereafter have to such jurisdiction or to the laying of the venue of any such suit, action or proceeding brought in such a court and any claim that such suit, action or proceeding has been brought in an inconvenient forum. You agree that effective service of process may be made upon you by mail under the notice provisions contained in Section 10 hereof.

6. **Termination.** Notwithstanding anything herein to the contrary, your employment shall terminate as a result of any of the following events:

(a) Your death;

(b) Termination by ATLS for Cause. "Cause" shall encompass any of the following: (i) you have committed any demonstrable and material act of fraud; (ii) illegal or gross misconduct by you that is willful and results in damage to the business or reputation of the



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Company; (iii) you are charged with a felony; (iv) the continued failure of you to substantially to perform your duties under this Agreement (other than as a result of physical or mental illness or injury) after ATLS delivers you a written demand for substantial performance that specifically identifies, with reasonable opportunity to cure, the manner in which ATLS believes that you have not substantially performed your duties; or (v) you have failed to follow reasonable written directions of ATLS which are consistent with your duties hereunder and not in violation of applicable law. ATLS' s termination of your employment for Cause shall be effected by ATLS providing you written notice ("Notice of Termination for Cause") of its intention to terminate your employment for Cause, setting forth in reasonable detail the specific conduct constituting Cause and the specific provision(s) of this Agreement on which it relies. You shall have ten (10) business days after receipt of such written notice to cure such failure (to the extent then curable);

(c) Termination by ATLS without Cause upon forty-five (45) days' prior written notice to you;

(d) Termination by ATLS upon your Disability. "Disability" shall mean that you become disabled by reason of physical or mental disability for more than one hundred eighty (180) days in the aggregate or a period of ninety (90) consecutive days during any 365-day period and the Board of Directors of ATLS determines, in good faith, that you, by reason of such physical or mental disability, are rendered unable to perform your duties and services hereunder. A termination of your employment by ATLS for Disability shall be communicated to you by written notice, and shall be effective on the thirtieth (30<sup>th</sup>) day after your receipt of such notice (the "Disability Effective Date"), unless you return to full-time performance of your duties before the Disability Effective Date;

(e) Termination by you for "Good Reason" upon thirty (30) days' prior written notice to ATLS. "Good Reason" shall mean: (i) a material reduction in Annual Base Salary, (ii) a demotion of you from the Position, (iii) a material reduction of your duties under this Agreement; provided that you and ATLS acknowledge that your duties will have been materially reduced if ATLS ceases to be a public company and the Chief Executive Officer of ATLS or Chairman of the board of directors of Atlas Pipeline Holdings GP, LLC is not, immediately following the transaction pursuant to which ATLS ceases to be a public company, the Chief Executive Officer of ATLS (or the acquiring entity, if any), (iv) ATLS' s requiring you to be relocated to a location more than 35 miles from your location immediately prior to such relocation, or (v) any action or inaction that constitutes a material breach by ATLS of this Agreement; provided, however, that, other than in the case of a termination by you for Good Reason pursuant to the proviso clause in clause (iii) of this Section 6(e), a termination by you for Good Reason shall be effective only if such failure has not been cured within ninety (90) days after the occurrence of the event alleged to constitute Good Reason. A termination of your employment for Good Reason shall, subject to the cure right described in the immediately preceding sentence, be effectuated by you providing ATLS with thirty (30) days' prior written notice ("Notice of Termination for Good Reason") of the termination within two (2) months after the event alleged to constitute Good Reason, setting forth in reasonable detail the specific conduct of ATLS that constitutes Good Reason and the specific provision(s) of this Agreement on which you rely;

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(f) Your termination without Good Reason upon sixty (60) days' prior written notice to ATLS; and

(g) Termination by ATLS at the end of the Initial Employment Term or any Renewal Term by reason of non-renewal pursuant to the terms and conditions of Section 3. Such a termination shall constitute a termination without Cause for purposes of Sections 5(b) and 7(c)(iv) and otherwise constitute a resignation without Good Reason pursuant to Section 7(b).

(h) The "Date of Termination" means the date of your death, the Disability Effective Date, the date on which the termination of your employment by ATLS for Cause, by ATLS without Cause, or by you for Good Reason is effective, or the date on which the termination of employment by you without Good Reason is effective in accordance with this Agreement, as the case may be.

#### **7. Consideration Payable to You upon Termination.**

(a) **Disability/Death.** If your employment is terminated by reason of your Disability or death, ATLS shall pay to you or your designated beneficiaries (or, if there is no such beneficiary, to your estate or legal representative), as the case may be, in a single lump-sum cash payment within sixty (60) days after the Date of Termination, the sum of the following amounts:

(i) the portion of your Annual Base Salary through the Date of Termination that has been earned and not yet paid;

(ii) an amount in respect of the short-term cash incentive compensation opportunity awarded to you in respect of the fiscal year in which the Date of Termination occurs equal to the amount of short-term cash incentive compensation earned by you with respect to the prior fiscal year, multiplied by a fraction, the numerator of which is the number of days in the fiscal year in which the Date of Termination occurs through the Date of Termination, and the denominator of which is the total number of days in the fiscal year in which the Date of Termination occurs; and

(iii) any earned but unpaid short-term cash incentive compensation for a prior incentive period and, to the extent required to be paid under the terms of ATLS policy in effect from time to time and applicable law, any accrued but unpaid vacation pay.

All other benefits, payments or compensation provided to you hereunder shall terminate. Any restrictions on any APL and/or ATLS options to purchase units or restricted units outstanding and held by you on the Date of Termination shall terminate as of the Date of Termination, and all such options or units shall be fully vested and exercisable (to the extent applicable) and shall remain in effect and exercisable (to the extent applicable) through the end of their respective terms, without regard to the termination of your employment.

(b) **By ATLS for Cause; By You Other than for Good Reason.** If your employment is terminated by ATLS for Cause or if you terminate your employment other than for Good Reason, ATLS shall pay to you your accrued but unpaid Annual Base Salary through

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the Date of Termination and, to the extent required to be paid under the terms of ATLS policy in effect from time to time and applicable law, any accrued but unpaid vacation pay. All other benefits, payments or compensation to be provided to you hereunder shall be governed solely by the terms of the applicable plan.

(c) **By ATLS Other than For Cause or Disability/Death; By You for Good Reason.** If ATLS terminates your employment other than for Cause, Death or Disability, or if you terminate employment for Good Reason, in addition to payment of your accrued but unpaid Annual Base Salary and, to the extent required to be paid under the terms of ATLS policy in effect from time to time and applicable law, any accrued but unpaid vacation pay, in each case through the Date of Termination, if you sign and deliver to ATLS a customary release of claims against the Company and related parties with respect to all matters arising out of your employment by ATLS or the termination thereof (subject to certain exceptions set forth in such release) within fifty-three (53) days after the Date of Termination (such release in the form provided by ATLS, the “Release”), and the statutory period within which you may revoke the Release expires no later than sixty (60) days after the Date of Termination, ATLS shall pay to you:

(i) A pro-rated amount in respect of the short-term cash incentive compensation opportunity awarded to you in respect of the fiscal year in which the Date of Termination occurs based on actual performance for such year. The pro-rata amount will be calculated as the product of (A) the amount which would have been earned in respect of the award based on actual performance measured at the end of the applicable fiscal year and (B) a fraction, the numerator of which is the number of days in the fiscal year in which the Date of Termination occurs through the Date of Termination, and the denominator of which is the total number of days in the fiscal year in which the Date of Termination occurs. The pro-rated amount shall be paid in cash in a lump sum on the date on which you otherwise would have been paid such amount had you remained employed by ATLS;

(ii) Monthly severance pay in an amount equal to one-twelfth (1/12) of the sum of your (A) Annual Base Salary and (B) Annual Incentive Compensation (as defined below) for the portion of the Employment Term (taking into account any applicable Renewal Term pursuant to Section 3) remaining after the Date of Termination, assuming for this purpose that your termination of employment had not occurred (the “Severance Period”). The severance pay shall be payable in monthly installments during the Severance Period in accordance with ATLS’ s regular payroll practices, commencing on the sixtieth (60th) day after the Date of Termination, subject to the terms and conditions of Section 16(a), if applicable. “Annual Incentive Compensation” shall mean the amount of short-term cash incentive compensation earned by you in respect of the fiscal year prior to the fiscal year in which the Date of Termination occurs;

(iii) For the remainder of the Severance Period, you may elect continued health coverage under the Company’ s health plan in which you participated upon the Date of Termination, as in effect from time to time, provided that you shall be responsible for paying the full monthly cost of such coverage; and provided further that, if requested in writing by ATLS, you must timely elect continued coverage under Section 4980B(f) of the Internal Revenue Code of 1986, as amended (the “Code” and such coverage, the “COBRA”

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Coverage”), it being understood in all cases that the COBRA Coverage continuation period under Section 4980B of the Code shall run concurrently with the Severance Period. The monthly cost shall be the premium determined for purposes of COBRA Coverage under Section 4980B(f)(4) of the Code in effect from time to time (the “COBRA Premium”). Each month in which you pay the COBRA Premium, ATLS shall reimburse you for the COBRA Premium in an amount equal to the COBRA Premium less the monthly premium charge that is paid by the Company’s active employees for such coverage. As an alternative, where such coverage may not be continued (or where such continuation would adversely affect the tax status of the plan pursuant to which the coverage is provided or result in penalty taxes to you pursuant to Section 409A of the Code, ATLS may elect to pay you cash in lieu of such coverage in an amount equal to the product of the number of months then remaining in the Severance Period and the COBRA Premium.

(iv) Any restrictions on any APL and/or ATLS options to purchase units or restricted units outstanding and held by you on the Date of Termination shall terminate as of the Date of Termination, and all such options or units shall be fully vested and exercisable (to the extent applicable) and shall remain in effect and exercisable (to the extent applicable) through the end of their respective terms, without regard to the termination of your employment.

If you do not timely sign and deliver the Release or if you revoke the Release within the statutory period, you shall forfeit any and all rights to any amounts or benefits provided pursuant to this Section 7(c). The payments and benefits provided pursuant to this Section 7(c) are intended as liquidated damages for a termination of your employment by ATLS other than for Cause, Death or Disability or for the actions of ATLS leading to a termination of your employment by you for Good Reason, and shall be the sole and exclusive remedy therefor. You shall not be required to mitigate the amount of any payment provided for in this Section 7(c) by seeking other employment or otherwise, nor shall the amount of any payment or benefit provided for herein be reduced by any compensation or any retirement benefit heretofore or hereafter earned by you as the result of employment by any other person, firm or corporation. If you become entitled to receive payments provided for in Section 7(c) of this Agreement, you hereby waive your right to receive payments under any severance plan or similar program of the Company.

#### **8. Golden Parachute Excise Tax Modified Cutback.**

(a) Anything in this Agreement to the contrary notwithstanding, in the event Grant Thornton or such other accounting firm as shall be designated by ATLS (the “Accounting Firm”) shall determine that receipt of all payments or distributions by ATLS or its affiliates in the nature of compensation to you or for your benefit, whether paid or payable pursuant to this Agreement or otherwise (a “Payment”), would subject you to the excise tax under Section 4999 of the Code, the Accounting Firm shall determine whether to reduce any of the Payments paid or payable pursuant to Section 7(c) of this Agreement (the “Agreement Payments”) to the “Reduced Amount” (as defined below). The Agreement Payments shall be reduced to the Reduced Amount only if the Accounting Firm determines that you would have a greater “Net After-Tax Receipt” (as defined below) of aggregate Payments if your Agreement Payments were reduced to the Reduced Amount. If the Accounting Firm determines that you would not have a greater Net

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After-Tax Receipt of aggregate Payments if your Agreement Payments were so reduced, you shall receive all Agreement Payments to which you are entitled under this Agreement.

(b) If the Accounting Firm determines that aggregate Agreement Payments should be reduced to the Reduced Amount, ATLS shall promptly give you notice to that effect and a copy of the detailed calculation thereof. All determinations made by the Accounting Firm under this Section 8 shall be binding upon ATLS and you absent manifest error and shall be made as soon as reasonably practicable and in no event later than fifteen (15) days following the applicable Date of Termination. For purposes of reducing the Agreement Payments to the Reduced Amount, only amounts payable under this Agreement (and no other Payments) shall be reduced. All fees and expenses of the Accounting Firm shall be borne solely by ATLS.

(c) As a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that amounts will have been paid or distributed by ATLS to or for the benefit of you pursuant to this Agreement which should not have been so paid or distributed (“Overpayment”) or that additional amounts which will have not been paid or distributed by ATLS to or for the benefit of you pursuant to this Agreement could have been so paid or distributed (“Underpayment”), in each case, consistent with the calculation of the Reduced Amount hereunder. In the event that the Accounting Firm, based upon the assertion of a deficiency by the Internal Revenue Service against either ATLS or you which the Accounting Firm believes has a high probability of success determines that an Overpayment has been made, you shall pay any such Overpayment to ATLS together with interest at the applicable federal rate provided for in Section 7872(f)(2) of the Code; provided, however, that no amount shall be payable by you to the Company if and to the extent such payment would not either reduce the amount on which you are subject to tax under Section 1 and Section 4999 of the Code or generate a refund of such taxes. In the event that the Accounting Firm, based upon controlling precedent or substantial authority, determines that an Underpayment has occurred, any such Underpayment shall be paid promptly (and in no event later than 60 days following the date on which the Underpayment is determined) by ATLS to or for the benefit of you together with interest at the applicable federal rate provided for in Section 7872(f)(2) of the Code.

(d) For purposes hereof, (i) “Reduced Amount” shall mean the greatest amount of Agreement Payments that can be paid that would not result in the imposition of the excise tax under Section 4999 of the Code if the Accounting Firm determines to reduce Agreement Payments pursuant to Section 8(a), and (ii) “Net After-Tax Receipt” shall mean the present value (as determined in accordance with Sections 280G(b)(2)(A)(ii) and 280G(d)(4) of the Code) of a Payment net of all taxes imposed on you with respect thereto under Sections 1 and 4999 of the Code and under applicable state and local laws, determined by applying the highest marginal rate under Section 1 of the Code and under state and local laws which applied to your taxable income for the immediately preceding taxable year, or such other rate(s) as the Accounting Firm determined to be likely to apply to you in the relevant tax year(s).

(e) To the extent requested by you, ATLS shall cooperate with you in good faith in valuing, and the Accounting Firm shall take into account the value of, services provided or to be provided by you (including without limitation, your agreeing to refrain from performing services pursuant to a covenant not to compete or similar covenant) before, on or after the date of

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a change in ownership or control of ATLS (within the meaning of Q&A-2(b) of the final regulations under Section 280G of the Code), such that payments in respect of such services may be considered reasonable compensation within the meaning of Q&A-9 and Q&A-40 to Q&A-44 of the final regulations under Section 280G of the Code and/or exempt from the definition of the term “parachute payment” within the meaning of Q&A-2(a) of the final regulations under Section 280G of the Code in accordance with Q&A-5(a) of the final regulations under Section 280G of the Code.

9. **Survivorship.** The respective rights and obligations of the parties under this Agreement shall survive any termination of your employment to the extent necessary to the intended preservation of such rights and obligations.

10. **Notices.** All notices and other communications required or permitted under this Agreement or necessary or convenient in connection herewith shall be in writing and shall be deemed to have been given when hand delivered or delivered by nationally recognized overnight delivery service, as follows (provided that notice of change of address shall be deemed given only when received):

If to the Company, to:

Atlas Energy, L.P.  
1845 Walnut Street, 10<sup>th</sup> Fl.  
Philadelphia, PA 19103  
Attn: Chief Legal Officer

If to you, to:

Mr. Eugene N. Dubay

or to such other names or addresses as the Company or you, as the case may be, shall designate by notice to each other person entitled to receive notices in the manner specified in this Section.

11. **Contents of Agreement; Amendment and Assignment.**

(a) This Agreement sets forth the entire understanding between the parties with respect to the subject matter hereof and cannot be changed, modified, extended or terminated except upon written amendment approved by the Board of ATLS and executed on its behalf by a duly authorized officer and by you.

(b) All of the terms and provisions of this Agreement shall be binding upon and inure to the benefit of and be enforceable by the respective heirs, executors, administrators, legal representatives, successors and assigns of the parties hereto, except that your duties and responsibilities under this Agreement are of a personal nature and shall not be assignable or delegatable in whole or in part by you.

12. **Severability.** If any provision of this Agreement or application thereof to anyone or under any circumstances is adjudicated to be invalid or unenforceable in any jurisdiction, such invalidity or unenforceability shall not affect any other provision or application of this Agreement which can be given effect without the invalid or unenforceable provision or application and shall not invalidate or render unenforceable such provision or application in any

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other jurisdiction. If any provision is held void, invalid or unenforceable with respect to particular circumstances, it shall nevertheless remain in full force and effect in all other circumstances.

13. **Remedies Cumulative; No Waiver.** No remedy conferred upon a party by this Agreement is intended to be exclusive of any other remedy, and each and every such remedy shall be cumulative and shall be in addition to any other remedy given under this Agreement or now or hereafter existing at law or in equity. No delay or omission by a party in exercising any right, remedy or power under this Agreement or existing at law or in equity shall be construed as a waiver thereof, and any such right, remedy or power may be exercised by such party from time to time and as often as may be deemed expedient or necessary by such party in its sole discretion.

14. **Withholding.** All payments under this Agreement shall be made subject to applicable tax withholding, and the Company shall withhold from any payments under this Agreement all federal, state and local taxes as the Company is required to withhold pursuant to any law or governmental rule or regulation. Except as specifically provided otherwise in this Agreement, you shall bear all expense of, and be solely responsible for, all federal, state and local taxes due with respect to any payment received under this Agreement.

15. **Governing Law.** This Agreement shall be governed by and interpreted under the laws of the State of Delaware without giving effect to any conflict of laws provisions.

16. **Section 409A.**

(a) Notwithstanding anything in this Agreement to the contrary, if you are a “specified employee” (as defined under Section 409A of the Code), payment of any amount under this Agreement shall, to the extent necessary in order to avoid the imposition of a penalty or other tax on you under Section 409A of the Code, be delayed for a period of six (6) months after your “separation from service” (within the meaning of Section 409A of the Code), and the accumulated postponed amount shall be paid in a lump-sum payment within ten (10) days after the end of the six (6)-month period. If you die during the six (6)-month postponement period prior to the payment of such postponed amount, the amounts withheld on account of Section 409A of the Code shall be paid to the personal representative of your estate within sixty (60) days after the date of your death.

(b) This Agreement is intended to comply with the requirements of Section 409A of the Code or an exemption thereto and shall in all respects be administered in accordance with Section 409A of the Code or an exemption thereto. Notwithstanding anything in the Agreement to the contrary, distributions may, to the extent necessary in order to avoid the imposition of a penalty or other tax on you under Section 409A of the Code, only be made under the Agreement upon an event and in a manner permitted by Section 409A of the Code or an applicable exemption. All payments to be made upon a termination of employment under this Agreement may, to the extent necessary in order to avoid the imposition of a penalty or other tax on you under Section 409A of the Code, only be made upon a “separation from service” (within the meaning of Section 409A of the Code). For purposes of Section 409A of the Code, the right to a series of payments under this Agreement shall be treated as a right to a series of separate

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payments. In no event may you, directly or indirectly, designate the calendar year of any payment under this Agreement. All reimbursements and in-kind benefits provided under this Agreement shall be made or provided in accordance with the requirements of Section 409A of the Code, including, where applicable, the requirement that (i) any reimbursement shall be for expenses incurred during your lifetime (or during a shorter period of time specified in this Agreement), (ii) the amount of expenses eligible for reimbursement, or in-kind benefits provided, during a calendar year may not affect the expenses eligible for reimbursement, or in-kind benefits to be provided, in any other calendar year, (iii) the reimbursement of an eligible expense will be made on or before the last day of the calendar year following the year in which the expense is incurred, and (iv) the right to reimbursement or in-kind benefits is not subject to liquidation or exchange for another benefit.

*{Signature Page Follows}*



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By execution hereof, you are confirming that you are free to enter into employment with ATLS pursuant to the terms identified herein. Please acknowledge your acceptance of and agreement to the terms of this Agreement by signing a copy of this Agreement where indicated and returning it to me.

Sincerely,

ATLAS ENERGY, L.P.

By: Atlas Energy GP, LLC, its general partner

By: /s/ Lisa Washington

Name: Lisa Washington

Title: Chief Legal Officer

**ACCEPTED AND AGREED:**

/s/ Eugene N. Dubay

Eugene N. Dubay

**Atlas Pipeline Partners, L.P.**  
**Statement of Computation of Ratio of Earnings to Fixed Charges**  
**(UNAUDITED)**  
**(amounts in thousands, except ratios)**

	Nine Months Ended	
	September 30,	
	2011	2010 <sup>(1)</sup>
<b>Earnings:</b>		
Income (loss) from continuing operations before income tax expense <sup>(2)(3)</sup>	\$300,732	\$(29,685)
Fixed charges	29,012	76,998
Adjustment to net distributed income from equity investee	(386 )	4,139
Interest capitalized	(3,021 )	(787 )
Amortization of previously capitalized interest	241	456
Non-controlling interest	(4,492 )	(3,338 )
Total	<u>\$322,086</u>	<u>\$47,783</u>
<b>Fixed Charges:</b>		
Interest cost and debt expense	\$24,525	\$74,043
Interest capitalized	3,021	787
Interest allocable to rental expense <sup>(4)</sup>	1,466	2,168
Total Fixed Charges	<u>\$29,012</u>	<u>\$76,998</u>
Preferred dividends	389	240
Total Fixed Charges and Preferred Dividends	<u>\$29,401</u>	<u>\$77,238</u>
<b>Ratio of Earnings to Fixed Charges</b>	<u>11.1x</u>	– <sup>(5)</sup>
<b>Ratio of Earnings to Fixed Charges and Preferred Dividends</b>	<u>11.0x</u>	– <sup>(6)</sup>

- (1) Adjusted to reflect the reclassification of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt.
- (2) Includes a \$255.7 million gain on asset sale and a \$22.5 million non-cash gain recognized on derivatives for the nine months ended September 30, 2011.
- (3) Includes a non-cash gain recognized on derivatives of \$21.1 million and a non-recurring cash derivative early termination expense of \$22.4 million for the nine months ended September 30, 2010.
- (4) Represents one-third of the total operating lease rental expense which is that portion deemed to be interest.
- (5) The Partnership earnings were insufficient to cover its fixed charges by \$29.2 million for this period.
- (6) The Partnership earnings were insufficient to cover its fixed charges and preferred dividends by \$29.5 million for this period.

## CERTIFICATION

I, Eugene N. Dubay, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Atlas Pipeline Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ EUGENE N. DUBAY

Name: Eugene N. Dubay

Title: Chief Executive Officer and President of the  
General Partner

Date: November 7, 2011

## CERTIFICATION

I, Robert W. Karlovich, III, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Atlas Pipeline Partners, L.P.;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
  - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
  - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
  - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
  - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
  - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
  - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

By: /s/ ROBERT W. KARLOVICH, III

Name: Robert W. Karlovich, III

Title: Chief Financial Officer of the General Partner

Date: November 7, 2011

**CERTIFICATION PURSUANT TO  
18 U.S.C. SECTION 1350,  
AS ADOPTED PURSUANT TO  
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Atlas Pipeline Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended September 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Eugene N. Dubay, Chief Executive Officer of the General Partner, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ EUGENE N. DUBAY

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Eugene N. Dubay  
Chief Executive Officer and President of the General  
Partner  
November 7, 2011

**CERTIFICATION PURSUANT TO  
18 U.S.C. SECTION 1350,  
AS ADOPTED PURSUANT TO  
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Quarterly Report of Atlas Pipeline Partners, L.P. (the "Partnership") on Form 10-Q for the quarter ended September 30, 2011 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert W. Karlovich, III, Chief Financial Officer of the General Partner, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

- (1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934, and
- (2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Partnership.

/s/ ROBERT W. KARLOVICH, III

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Robert W. Karlovich, III

Chief Financial Officer of the General Partner

November 7, 2011

**Consolidated Statements Of  
Operations (USD \$)  
In Thousands, except Share  
data**

	<b>3 Months Ended</b>		<b>9 Months Ended</b>	
	<b>Sep. 30, 2011</b>	<b>Sep. 30, 2010</b>	<b>Sep. 30, 2011</b>	<b>Sep. 30, 2010</b>
<b>Revenue:</b>				
<a href="#">Natural gas and liquids</a>	\$ 341,498	\$ 220,478	\$ 937,975	\$ 641,978
<a href="#">Transportation, processing and other fees - third parties</a>	11,612	9,810	31,280	29,472
<a href="#">Transportation, processing and other fees - affiliates</a>	79	141	256	472
<a href="#">Other income (loss), net</a>	26,591	(4,311)	17,317	10,576
<a href="#">Total revenue and other income (loss), net</a>	379,780	226,118	986,828	682,498
<b>Costs and expenses:</b>				
<a href="#">Natural gas and liquids</a>	282,391	178,920	774,859	521,495
<a href="#">Plant operating</a>	14,085	12,552	40,240	36,492
<a href="#">Transportation and compression</a>	268	300	603	721
<a href="#">General and administrative</a>	8,686	7,203	25,477	22,396
<a href="#">Compensation reimbursement - affiliates</a>	463	375	1,344	1,125
<a href="#">Other costs</a>	8	0	583	0
<a href="#">Depreciation and amortization</a>	19,471	18,566	57,499	55,647
<a href="#">Interest</a>	5,935	23,087	24,525	74,085
<a href="#">Total costs and expenses</a>	331,307	241,003	925,130	711,961
<a href="#">Equity income in joint ventures</a>	1,785	1,787	2,934	4,137
<a href="#">Gain on asset sale</a>	0	0	255,674	0
<a href="#">Loss on early extinguishment of debt</a>	0	(4,359)	(19,574)	(4,359)
<a href="#">Income (loss) from continuing operations</a>	50,258	(17,457)	300,732	(29,685)
<b>Discontinued operations:</b>				
<a href="#">Gain (loss) on sale of discontinued operations</a>	0	311,492	(81)	311,492
<a href="#">Earnings (loss) from discontinued operations</a>	0	(5,565)	0	9,192
<a href="#">Income (loss) from discontinued operations</a>	0	305,927	(81)	320,684
<a href="#">Net income</a>	50,258	288,470	300,651	290,999
<a href="#">Income attributable to non-controlling interests</a>	(1,760)	(1,076)	(4,492)	(3,338)
<a href="#">Preferred unit dividends</a>	0	(240)	(389)	(240)
<a href="#">Net income attributable to common limited partners and the General Partner</a>	48,498	287,154	295,770	287,421
<b>Allocation of net income (loss) attributable to Common limited partner interest:</b>				
<a href="#">Continuing operations</a>	47,091	(18,414)	289,472	(32,627)
<a href="#">Discontinued operations</a>	0	300,085	(79)	314,559
<a href="#">Total common limited partner interest</a>	47,091	281,671	289,393	281,932
<b>General Partner interest:</b>				
<a href="#">Continuing operations</a>	1,407	(359)	6,379	(636)
<a href="#">Discontinued operations</a>	0	5,842	(2)	6,125
<a href="#">Total General Partner interest</a>	1,407	5,483	6,377	5,489
<b>Net income (loss) attributable to:</b>				
<a href="#">Continuing operations</a>	48,498	(18,773)	295,851	(33,263)

<u>Discontinued operations</u>	0	305,927	(81)	320,684
<u>Net income (loss) attributable to common limited partners and the General Partner</u>	\$ 48,498	\$ 287,154	\$ 295,770	\$ 287,421
<b><u>Net income (loss) attributable to common limited partners per unit: Basic:</u></b>				
<u>Continuing operations</u>	\$ 0.87	\$ (0.34)	\$ 5.37	\$ (0.61)
<u>Discontinued operations</u>	\$ 0.00	\$ 5.63	\$ 0.00	\$ 5.92
<u>Total net income attributable to common limited partners per unit-basic</u>	\$ 0.87	\$ 5.29	\$ 5.37	\$ 5.31
<u>Weighted average common limited partner units (basic)</u>	53,588	53,277	53,494	53,115
<b><u>Diluted:</u></b>				
<u>Continuing operations</u>	\$ 0.87	\$ (0.34)	\$ 5.37	\$ (0.61)
<u>Discontinued operations</u>	\$ 0.00	\$ 5.63	\$ 0.00	\$ 5.92
<u>Total net income attributable to common limited partners per unit-diluted</u>	\$ 0.87	\$ 5.29	\$ 5.37	\$ 5.31
<u>Weighted average common limited partner units (diluted)</u>	54,012	53,277	53,923	53,115



Consolidated Statement Of Equity (USD \$) In Thousands, except Share data	Number Of Limited Partner Units Class C Preferred [Member]	Number Of Limited Partner Units Common [Member]	Class C Preferred Limited Partner [Member] USD (\$)	Common Limited Partners [Member] USD (\$)	General Partner [Member] USD (\$)	Accumulated Other Comprehensive Loss [Member] USD (\$)	Non- controlling Interest [Member] USD (\$)	Total USD (\$)
<a href="#">Balance, value at Dec. 31, 2010</a>			\$ 8,000	\$ 1,057,342	\$ 20,066	\$ (11,224)	\$ (32,537)	\$ 1,041,647
<a href="#">Balance, units at Dec. 31, 2010</a>	8,000	53,338,010						
<a href="#">Redemption of Class C cumulative preferred limited partner units</a>	(8,000)							
<a href="#">Redemption of Class C cumulative preferred limited partner units, value</a>			(8,000)					(8,000)
<a href="#">Issuance of units under incentive plans, units</a>		306,275						
<a href="#">Issuance of units under incentive plans, value</a>				468				468
<a href="#">Repurchase and retirement of common limited partner units</a>		(28,878)						
<a href="#">Purchase and retirement of treasury units</a>				(984)				(984)
<a href="#">Distributions paid</a>			(629)	(66,869)	(1,804)			(69,302)
<a href="#">Distributions payable</a>			240					240
<a href="#">Distributions paid to non- controlling interests</a>							(1,820)	(1,820)
<a href="#">Unissued units under incentive plans</a>				2,300				2,300
<a href="#">Other comprehensive income</a>						5,118		5,118
<a href="#">Net income</a>			389	289,393	6,377		4,492	300,651
<a href="#">Balance, value at Sep. 30, 2011</a>			\$ 0	\$ 1,281,650	\$ 24,639	\$ (6,106)	\$ (29,865)	\$ 1,270,318
<a href="#">Balance, units at Sep. 30, 2011</a>	0	53,615,407						

**Document And Entity  
Information**

**9 Months Ended  
Sep. 30, 2011**

**Nov. 02, 2011**

**[Document And Entity Information \[Abstract\]](#)**

<u><a href="#">Document Type</a></u>	10-Q	
<u><a href="#">Amendment Flag</a></u>	false	
<u><a href="#">Document Period End Date</a></u>	Sep. 30, 2011	
<u><a href="#">Document Fiscal Year Focus</a></u>	2011	
<u><a href="#">Document Fiscal Period Focus</a></u>	Q3	
<u><a href="#">Entity Registrant Name</a></u>	ATLAS PIPELINE PARTNERS LP	
<u><a href="#">Entity Central Index Key</a></u>	0001092914	
<u><a href="#">Current Fiscal Year End Date</a></u>	--12-31	
<u><a href="#">Entity Filer Category</a></u>	Accelerated Filer	
<u><a href="#">Entity Common Stock, Shares Outstanding</a></u>		53,616,683

**Property, Plant And  
Equipment**

**9 Months Ended  
Sep. 30, 2011**

[Property, Plant And  
Equipment \[Abstract\]](#)

[Property, Plant And  
Equipment](#)

**NOTE 7 – PROPERTY, PLANT AND EQUIPMENT**

The following is a summary of property, plant and equipment, including leased property and equipment meeting capital lease criteria (see Note 11) (in thousands):

	<b>September 30, 2011</b>	<b>December 31, 2010</b>	<b>Estimated Useful Lives in Years</b>
Pipelines, processing and compression facilities	\$ 1,517,573	\$ 1,340,944	2 – 40
Rights of way	158,602	156,713	20 – 40
Buildings	8,047	8,047	40
Furniture and equipment	9,404	8,981	3 – 7
Other	13,800	12,659	3 – 10
	<u>1,707,426</u>	<u>1,527,344</u>	
Less – accumulated depreciation	<u>(225,985)</u>	<u>(186,342)</u>	
	<u>\$ 1,481,441</u>	<u>\$ 1,341,002</u>	

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. 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. The Partnership recorded depreciation expense on property, plant and equipment, including amortization of capital lease arrangements (see Note 11), of \$13.8 million and \$12.8 million for the three months ended September 30, 2011 and 2010, respectively, and \$40.2 million and \$38.3 million for the nine months ended September 30, 2011 and 2010, respectively, on its consolidated statements of operations.

**Commitments And  
Contingencies**

**9 Months Ended  
Sep. 30, 2011**

[Commitments And  
Contingencies \[Abstract\]](#)  
[Commitments And  
Contingencies](#)

**NOTE 12 — COMMITMENTS AND CONTINGENCIES**

The Partnership has certain long-term unconditional purchase obligations and commitments, primarily take-or-pay agreements. These agreements provide transportation services to be used in the ordinary course of the Partnership's operations.

The Partnership is, or may become, a party to various routine legal proceedings arising out of the ordinary course of its business. Management of the Partnership believes 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 aggregate cap (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.

There were no substantive developments with respect to Williams' indemnity claims during the three months ended September 30, 2011. As previously reported, 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 may be entitled to indemnification from Atlas Energy, Inc. with respect to a small portion of Williams' claims.

**NOTE 3 – INVESTMENT IN JOINT VENTURES***Laurel Mountain*

On February 17, 2011, the Partnership completed the sale of its 49% non-controlling interest in Laurel Mountain 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 on its consolidated statements of operations a net gain on the sale of assets of \$253.5 million. The Partnership recognized a \$255.7 million gain during the nine months ended September 30, 2011 and a \$2.2 million loss during the year ended December 31, 2010 for expenses related to the sale. 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 11) and for general company 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 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 reclassify the earnings or the gain on sale related to Laurel Mountain to discontinued operations upon the sale of its ownership interest.

The Partnership retained its preferred distribution rights with respect to a \$25.5 million note receivable due from Williams, an investment grade rated entity, related to the formation of Laurel Mountain in 2009, including interest due on this note. Interest is received on the last day of each quarter. The preferred distribution rights with respect to the note receivable have been reclassified from investment in joint ventures to 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. During the three and nine months ended September 30, 2010, the Partnership utilized \$8.5 million and \$15.3 million of the note receivable, respectively, and made cash payments of \$1.3 million and \$6.9 million, respectively, for capital contributions to Laurel Mountain. As of September 30, 2011, the Partnership has utilized \$17.0 million of the \$25.5 million note receivable, resulting in a remaining balance of \$8.5 million.

*West Texas LPG Pipeline Limited Partnership*

On May 11, 2011, the Partnership acquired a 20% interest in West Texas LPG Pipeline Limited Partnership ("WTLPG") from Buckeye Partners, L.P. (NYSE: BPL) for \$85.0 million. WTLPG owns a common-carrier pipeline system that transports NGLs from New Mexico and Texas to Mont Belvieu, Texas for fractionation. WTLPG is operated by Chevron Pipeline Company, an affiliate of Chevron, which owns the remaining 80% interest. The Partnership recognizes its 20% interest in WTLPG as an investment in joint venture on its consolidated balance sheets. The Partnership accounts for its ownership interest in WTLPG under the equity method of accounting, with recognition of its ownership interest in the income of WTLPG as equity income on its consolidated statements of operations. The Partnership incurred costs of \$0.6 million during the nine months ended September 30, 2011, related to the acquisition of WTLPG, which are reported as other costs within the Partnership's consolidated statements of operations.

The following tables summarize the components of the investment in joint ventures on the Partnership's consolidated balance sheets and the components of equity income on the Partnership's statements of operations (in thousands).

	<b>September 30, 2011</b>	<b>December 31, 2010</b>
Investment in Laurel Mountain	\$ —	\$ 153,358

Investment in WTLPG	86,688	–
Investment in joint ventures	<u>\$ 86,688</u>	<u>\$ 153,358</u>

	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Equity income in Laurel Mountain	\$ –	\$ 1,787	\$ 462	\$ 4,137
Equity income in WTLPG	1,785	–	2,472	–
Equity income in joint ventures	<u>\$ 1,785</u>	<u>\$ 1,787</u>	<u>\$ 2,934</u>	<u>\$ 4,137</u>

[Derivative Instruments](#)[\[Abstract\]](#)[Derivative Instruments](#)**NOTE 9 — DERIVATIVE INSTRUMENTS**

The Partnership uses derivative instruments in connection with its commodity price 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 its derivatives. As such, changes in fair value of derivatives are recognized immediately within other income (loss), net in its consolidated statements of operations. The change in fair value of commodity-based derivative instruments, which was previously recognized in accumulated other comprehensive loss within equity on the Partnership's consolidated balance sheets, will be reclassified to the Partnership's consolidated statements of operations in the future at the time the originally hedged physical transactions affect earnings. The Partnership will reclassify \$4.7 million of the \$6.1 million net loss in accumulated other comprehensive loss, within equity on the Partnership's consolidated balance sheets at September 30, 2011, to natural gas and liquids revenue on the Partnership's consolidated statements of operations over the next twelve-month period. Aggregate losses of \$1.4 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 assets on its consolidated balance sheet of \$38.8 million at September 30, 2011 and net derivative liabilities on its consolidated balance sheet of \$10.2 million at December 31, 2010.

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

	<u>September 30, 2011</u>	<u>December 31, 2010</u>
Current portion of derivative assets	\$ 11,887	\$ —
Long-term portion of derivative assets	26,950	—
Current portion of derivative liabilities	—	(4,564)
Long-term portion of derivative liabilities	—	(5,608)
Net derivative assets/(liabilities)	<u>\$ 38,837</u>	<u>\$ (10,172)</u>

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

<u>Balance Sheet Location</u>	<u>September 30, 2011</u>	<u>December 31, 2010</u>
<b>Asset Derivatives</b>		
Current portion of derivative assets	\$ 17,582	\$ —
Long-term portion of derivative assets	28,522	—
Current portion of derivative liabilities	—	2,624
Long-term portion of derivative liabilities	—	1,052



Total assets	46,104	3,676
<b>Liability Derivatives</b>		
Current portion of derivative assets	(5,695)	-
Long-term portion of derivative assets	(1,572)	-
Current portion of derivative liabilities	-	(7,188)
Long-term portion of derivative liabilities	-	(6,660)
Total liabilities	(7,267)	(13,848)
<b>Total Derivatives</b>	<b>\$ 38,837</b>	<b>\$ (10,172)</b>

The following table summarizes the Partnership's commodity derivatives as of September 30, 2011, none of which are designated for hedge accounting (dollars and volumes in thousands):

**Fixed Price Swaps**

Production Period	Purchased/Sold	Commodity	Volumes <sup>(1)</sup>	Average Fixed Price	Fair Value <sup>(2)</sup> Asset/(Liability)
<b>Natural Gas</b>					
2011	Sold	Natural Gas Basis	480	\$ (0.728)	\$ (284)
2011	Purchased	Natural Gas Basis	480	(0.758)	298
2011	Sold	Natural Gas	1,200	4.910	1,337
<b>Natural Gas Liquids</b>					
2011	Sold	Ethane	2,142	0.730	(136)
2011	Sold	Propane	4,284	1.190	(1,342)
2011	Sold	Isobutane	504	1.628	(244)
2011	Sold	Normal Butane	1,386	1.590	(396)
2011	Sold	Natural Gasoline	3,276	2.042	(231)
2012	Sold	Ethane	1,890	0.700	(5)
2012	Sold	Propane	19,278	1.302	(527)
2012	Sold	Normal Butane	3,276	1.902	440
2012	Sold	Isobutane	504	1.970	(13)
2012	Sold	Natural Gasoline	4,158	2.401	1,807
<b>Crude Oil</b>					
2011	Sold	Crude Oil	30	90.75	343
2012	Sold	Crude Oil	180	103.76	4,100
<b>Total Fixed Price Swaps</b>					<b>\$ 5,147</b>

**Options**

Production Period	Purchased/Sold	Type	Commodity	Volumes <sup>(1)</sup>	Average Strike Price	Fair Value <sup>(2)</sup> Asset/(Liability)
<b>Natural Gas Liquids</b>						
2011	Purchased	Put	Ethane	2,142	\$ 0.735	\$ 57
2011	Purchased	Put	Propane	5,040	1.383	292
2012	Purchased	Put	Ethane	1,890	0.700	157
2012	Purchased	Put	Propane	28,476	1.386	6,476
2012	Purchased	Put	Natural Gasoline	2,520	2.400	950
2013	Purchased	Put	Normal Butane	10,458	1.667	3,459
2013	Purchased	Put	Isobutane	4,158	1.687	1,311
2013	Purchased	Put	Natural Gasoline	23,940	2.108	10,219
<b>Crude Oil</b>						
2011	Purchased	Put	Crude Oil	93	99.45	1,911

2011	Sold	Call	Crude Oil	170	93.35	(208)
2011	Purchased <sup>(3)</sup>	Call	Crude Oil	63	125.20	3
2012	Purchased	Put	Crude Oil	180	106.42	5,146
2012	Sold	Call	Crude Oil	498	94.69	(3,210)
2012	Purchased <sup>(3)</sup>	Call	Crude Oil	180	125.20	301
2013	Purchased	Put	Crude Oil	282	100.10	6,826

**Total Options** \$ 33,690

**Total Fair Value** \$ 38,837

(1) Volumes for natural gas are stated in MMBTU's. Volumes for NGLs are stated in gallons. Volumes for crude oil are stated in barrels.

(2) See Note 10 for discussion on fair value methodology.

(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 nine months ended September 30, 2010, the Partnership made net payments of \$25.3 million related to the early termination of derivative contracts, which were recorded within the Partnership's consolidated statements of operations. The terminated derivative contracts were to expire at various times through the fourth quarter of 2010. No contracts were terminated early during the nine months ended September 30, 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 September 30,		For the Nine Months ended September 30,		
	2011	2010	2011	2010	
<b><u>Loss reclassified from Accumulated other comprehensive loss into Income</u></b>					
<b><u>Contract Type</u></b>	<b><u>Location</u></b>				
Interest rate contracts <sup>(1)</sup>	Interest expense	\$ -	\$ -	\$ -	\$ (2,242)
Commodity contracts <sup>(1)</sup>	Natural gas and liquids revenue	(1,714)	(2,411)	(5,118)	(13,159)
Commodity contracts <sup>(1)</sup>	Discontinued operations	-	(11,711)	-	(20,154)
Loss reclassified from Accumulated other comprehensive loss		<u>\$ (1,714)</u>	<u>\$ (14,122)</u>	<u>\$ (5,118)</u>	<u>\$ (35,555)</u>

**Gain (loss) recognized in income (derivatives not designated as hedges)**

<b><u>Contract type</u></b>	<b><u>Location</u></b>				
Interest rate contracts <sup>(2)</sup>	Other income (loss), net	\$ -	\$ -	\$ -	\$ (6)
Commodity contracts <sup>(2)</sup>	Other income (loss), net	23,760	(6,802)	8,952	3,139
Commodity contracts <sup>(2)</sup>	Discontinued operations	-	(1,555)	-	665
Gain (loss) recognized in income		<u>\$ 23,760</u>	<u>\$ (8,357)</u>	<u>\$ 8,952</u>	<u>\$ 3,798</u>

(1) Hedges previously designated as cash flow hedges

(2) Dedicating cash flow hedges and non-designated hedges

## Related Party Transactions

**9 Months Ended  
Sep. 30, 2011**

### [Related Party Transactions](#)

#### [\[Abstract\]](#)

### [Related Party Transactions](#)

#### **NOTE 14 — RELATED PARTY TRANSACTIONS**

The Partnership does not directly employ any persons to manage or operate its business. These functions are provided by the General Partner and employees of Atlas 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 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 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 (see Note 1). The Partnership reimbursed the General Partner and its affiliates \$0.4 million and \$0.4 million for the three months ended September 30, 2011 and 2010, respectively, and \$1.3 million and \$1.1 million for the nine months ended September 30, 2011 and 2010, respectively, for compensation and benefits related to its employees. There were no reimbursements for direct expenses incurred by the General Partner and its affiliates for the nine months ended September 30, 2011 and 2010. The General Partner believes the method utilized in allocating costs to the Partnership is reasonable.

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

**NOTE 10 — FAIR VALUE OF FINANCIAL INSTRUMENTS**

*Derivative Instruments*

The Partnership uses a valuation framework based upon inputs 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 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 9). At September 30, 2011, all 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 September 30, 2011 and December 31, 2010 (in thousands):

	<b>Level 1</b>	<b>Level 2</b>	<b>Level 3</b>	<b>Total</b>
<b>September 30, 2011</b>				
<b>Assets</b>				
Commodity swaps	\$ –	\$ 6,433	\$ 2,564	\$ 8,997
Commodity options	–	14,186	22,921	37,107
Total assets	–	20,619	25,485	46,104
<b>Liabilities</b>				
Commodity swaps	–	(638)	(3,212)	(3,850)
Commodity options	–	(3,417)	–	(3,417)
Total liabilities	–	(4,055)	(3,212)	(7,267)
Total derivatives	\$ –	\$ 16,564	\$ 22,273	\$ 38,837
<b>December 31, 2010</b>				
<b>Assets</b>				
Commodity swaps	\$ –	\$ 1,225	\$ 124	\$ 1,349
Commodity options	–	2,327	–	2,327

Total assets	—	3,552	124	3,676
<b>Liabilities</b>				
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 nine months ended September 30, 2011 (in thousands):

	<u>NGL Fixed Price Swaps</u>		<u>NGL Put Options</u>		<u>Total</u>
	<u>Volume</u>	<u>Amount</u>	<u>Volume</u>	<u>Amount</u>	<u>Amount</u>
Balance – December 31, 2010	32,760	\$ (1,790)	—	\$ —	\$ (1,790)
New contracts <sup>(1)</sup>	37,464	—	89,628	22,360	22,360
Cash settlements from unrealized gain (loss) <sup>(2)(3)</sup>	(29,526)	8,103	(11,004)	1,352	9,455
Net change in unrealized gain (loss) <sup>(2)</sup>	—	(6,961)	—	593	(6,368)
Deferred option premium recognition <sup>(3)</sup>	—	—	—	(1,384)	(1,384)
Balance – September 30, 2011	<u>40,698</u>	<u>\$ (648)</u>	<u>78,624</u>	<u>\$ 22,921</u>	<u>\$ 22,273</u>

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

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

(3) Includes option premium cost reclassified from unrealized gain (loss) to realized gain (loss) at time of option expiration.

#### *Other Financial Instruments*

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

The Partnership's current assets and liabilities on its consolidated balance sheets, other than the derivatives 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 September 30, 2011 and December 31, 2010, which consists principally of borrowings under the revolving credit facility, the 8.125% Senior Notes and the 8.75% Senior Notes, were \$429.2 million and \$532.3 million, respectively, compared with the carrying amounts of \$426.0 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, approximate their estimated fair value.

## Other Assets

9 Months Ended  
Sep. 30, 2011

[Other Assets \[Abstract\]](#)

[Other Assets](#)

### NOTE 8 – OTHER ASSETS

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

	<u>September 30,</u> <u>2011</u>	<u>December 31,</u> <u>2010</u>
Deferred finance costs, net of accumulated amortization of \$17,739 and \$24,436 at September 30, 2011 and December 31, 2010, respectively	\$ 18,988	\$ 26,227
Security deposits	2,853	2,841
	<u>\$ 21,841</u>	<u>\$ 29,068</u>

Deferred finance costs are recorded at cost and amortized over the term of the respective debt agreement (see Note 11). During the nine months ended September 30, 2011, the Partnership recorded \$5.2 million related to accelerated amortization of deferred financing costs associated with the retirement of its 8.125% Senior Notes and partial redemption of its 8.75% Senior Notes, which is included in loss on early extinguishment of debt on the Partnership's consolidated statements of operations (see Note 11). During the three and nine months ended September 2010, the Partnership recorded \$4.4 million of accelerated amortization of deferred financing costs associated with the retirement of its term loan with proceeds from the sale of its Elk City assets (see Note 4), which is included in loss on early extinguishment of debt on the Partnership's consolidated statements of operations. Amortization expense of deferred finance costs, excluding accelerated amortization expense, was \$1.1 million and \$1.5 million for the three months ended September 30, 2011 and 2010, respectively, and \$3.4 million and \$4.7 million for the nine months ended September 30, 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 - \$4.4 million; 2012 to 2014 - \$4.2 million per year; 2015 - \$3.9 million.

## Basis Of Presentation

**9 Months Ended  
Sep. 30, 2011**

[Basis Of Presentation](#)

[\[Abstract\]](#)

[Basis Of Presentation](#)

### **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 and the transportation of NGLs in the Mid-Continent. 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 September 30, 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., a publicly-traded partnership (NYSE: ATLS). The remaining 98.0% ownership interest in the consolidated operations consists of limited partner interests. At September 30, 2011, the Partnership had 53,615,407 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.

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. common units it held. On May 27, 2011, the Partnership redeemed the 8,000 \$1,000 par value 12% cumulative Class C preferred limited partner units held by Chevron (see Note 5).

The Partnership has adjusted its consolidated financial statements and related footnote disclosures presented within this Form 10-Q from amounts previously presented to reflect the reclassification of accelerated amortization of deferred financing costs. The Partnership has retrospectively adjusted its prior period consolidated financial statements to reclass the amounts from interest expense to loss on early extinguishment of debt.

The accompanying consolidated financial statements, which are unaudited except 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 nine month period ended September 30, 2011 may not necessarily be indicative of the results of operations for the full year ending December 31, 2011.



## Discontinued Operations

9 Months Ended

Sep. 30, 2011

[Discontinued Operations](#)

[\[Abstract\]](#)

[Discontinued Operations](#)

### 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 nine months ended September 30, 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 included within the Partnership's formerly reported Mid-Continent segment of operations, which was reclassified to the Partnership's current Gathering and Processing segment of operations (see Note 15).

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		Nine Months Ended	
	September 30,		September 30,	
	2011	2010	2011	2010
Total revenue and other income (loss), net..	\$ -	\$ 29,912	\$ -	\$ 129,928
Total costs and expenses	-	(35,477)	-	(120,736)
Gain (loss) on asset sales and other	-	311,492	(81)	311,492
Income (loss) from discontinued operations	\$ -	\$ 305,927	\$ (81)	\$ 320,684

The Partnership's continuing operations include \$0.6 million and \$18.0 million within natural gas and liquids revenue on the consolidated statements of operations for the three and nine months ended September 30, 2010, respectively, for intercompany sales from the WestOK system to Elk City. These intercompany sales were previously eliminated in consolidation prior to the sale of Elk City and were reinstated within natural gas and liquids revenue from continuing operations upon the sale of Elk City. In the periods subsequent to the sale of Elk City, these sales have been made directly to third parties.

**Preferred Unit Equity  
Offerings**

**9 Months Ended  
Sep. 30, 2011**

[Preferred Unit Equity  
Offerings \[Abstract\]](#)

[Preferred Unit Equity  
Offerings](#)

**NOTE 5 – PREFERRED UNIT EQUITY OFFERINGS**

On June 30, 2010, the Partnership sold 8,000 newly-created 12% Cumulative Class C Preferred Units of limited partner interest (the "Class C Preferred Units") to Atlas Energy, Inc. for cash consideration of \$1,000 per Class C Preferred Unit (the "Class C Preferred Unit Face Value"). The Class C Preferred Units were entitled to receive distributions of 12.0% per annum, paid quarterly on the same date as the distribution payment date for the Partnership's common units. The Class C Preferred Units were not convertible into common units of the Partnership. The Partnership had the right at any time to redeem some or all of the outstanding Class C Preferred Units for cash at an amount equal to the Class C Preferred Face Value being redeemed plus accrued but unpaid dividends.

On February 17, 2011, the Class C Preferred Units were acquired by Chevron as part of the Chevron Merger (see Note 1). On May 27, 2011, the Partnership redeemed all 8,000 Class C Preferred Units outstanding for cash at the liquidation value of \$1,000 per unit, or \$8.0 million, plus \$0.2 million, representing the accrued dividends on the 8,000 Class C Preferred Units prior to the Partnership's redemption. There are no longer any Class C Preferred Units outstanding. The Partnership recognized \$0.2 million of preferred dividend cost for the three months ended September 30, 2010 and \$0.4 million and \$0.2 million of preferred dividend cost for the nine months ended September 30, 2011 and 2010, respectively, which are presented as reductions of net income (loss) to determine net income (loss) attributable to common limited partners and the General Partner on its consolidated statements of operations.

## NOTE 13 — BENEFIT PLANS

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

A phantom unit entitles a grantee to receive a common limited partner unit upon vesting of the phantom unit. In tandem with phantom unit grants, participants may be granted a distribution equivalent right ("DER"), which is the right to receive cash per phantom unit in an amount equal to and at the same time as the cash distributions the Partnership makes on a common unit during the period the phantom unit is outstanding. Except for phantom units awarded to non-employee managing board members of the General Partner and within the guidelines proscribed in each long term incentive plan, a committee (the "LTIP Committee") appointed by the General Partner's managing board determines the vesting period for phantom units.

A unit option entitles a grantee to purchase a common limited partner unit upon payment of the exercise price for the option after completion of vesting of the unit option. The exercise price of the unit option is equal to the fair market value of the common unit on the date of grant of the option. The LTIP Committee shall determine how the exercise price may be paid by the grantee. The LTIP Committee will determine the vesting and exercise period for unit options. Unit option awards expire 10 years from the date of grant.

*Long-Term Incentive Plans*

The Partnership has a 2004 Long-Term Incentive Plan ("2004 LTIP") and a 2010 Long-Term Incentive Plan, 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 September 30, 2011, the Partnership had 389,765 phantom units outstanding under the Partnership's LTIPs, with 2,370,779 phantom units and unit options available for grant. The Partnership generally issues new common units for phantom units and unit options, which have vested and have been exercised.

*Partnership Phantom Units.* Through September 30, 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 may automatically vest upon a change of control, as defined in the LTIPs. At September 30, 2011, there were 193,248 units outstanding under the LTIPs that will vest within the following twelve months. The Partnership is authorized to repurchase common units to cover employee-related taxes on certain phantom units when they have vested. The Partnership purchased and retired 5,533 common units during both the three months ending September 30, 2011 and 2010 for a cost of \$0.2 million and \$0.1 million, respectively, and purchased 28,878 common units and 20,442 common units during the nine months ended September 30, 2011 and 2010, respectively for a cost of \$1.0 million and \$0.2 million, respectively, which was recorded as a reduction of Partners' capital on the Partnership's consolidated balance sheet. 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 represented all outstanding phantom units held by the CEO, automatically vested and were issued.

All phantom units outstanding under the LTIPs at September 30, 2011 include DERs granted to the participants by the LTIP Committee. The amounts paid with respect to LTIP DERs were \$0.2 and \$0.6 million during the three months and nine months ended September 30, 2011, respectively. These amounts were recorded as a reduction of Partners' capital on the Partnership's consolidated balance sheets. No DERs were paid during the nine months ended September 30, 2010.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	Number of Units	Fair Value <sup>(1)</sup>	Number of Units	Fair Value <sup>(1)</sup>	Number of Units	Fair Value <sup>(1)</sup>	Number of Units	Fair Value <sup>(1)</sup>
Outstanding, beginning of period	436,425	\$ 17.84	603,774	\$ 12.24	490,886	\$ 11.75	52,233	\$ 39.72
Granted	7,465	27.30	500	13.90	138,318	32.99	564,000	10.34
Matured and issued <sup>(2)</sup>	(46,375)	11.02	(103,625)	11.15	(231,689)	11.31	(114,209)	14.10
Forfeited	(7,750)	26.99	(4,500)	14.83	(7,750)	26.99	(5,875)	21.65
Outstanding, end of	389,765	\$ 19.24	496,149	\$ 12.43	389,765	\$ 19.24	496,149	\$ 12.43

period <sup>(3)(4)</sup> ...							
Matured and not issued <sup>(5)</sup>	750	\$ 11.12	250	\$ 44.51	750	\$ 11.12	\$ 44.51
Non-cash compensation expense recognized (in thousands) <sup>(6)</sup>		\$ 822		\$ 763		\$ 2,498	\$ 2,788

- (1) Fair value based upon weighted average grant date price.
- (2) The intrinsic values for phantom unit awards exercised during the three months ended September 30, 2011 and 2010 were \$1.5 million and \$1.2 million, respectively, and \$7.4 million and \$1.3 million during the nine months ended September 30, 2011 and 2010, respectively.
- (3) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2011 and 2010 was \$11.6 million and \$8.7 million, respectively.
- (4) There were 15,701 and 3,898 outstanding phantom unit awards at September 30, 2011 and 2010, respectively, which were classified as liabilities due to a cash option available on the related phantom unit awards.
- (5) The aggregate intrinsic value for phantom unit awards vested but not issued at September 30, 2011 and 2010 was \$24 thousand and \$3 thousand, respectively.
- (6) Non-cash compensation expense for the nine months ended September 30, 2011 includes incremental compensation expense of \$472 thousand, related to the accelerated vesting of phantom units held by the CEO of the General Partner. Non-cash compensation expense includes \$0.2 million and \$2.0 million related to Bonus Units converted to phantom units during the three and nine months ended September 30, 2010, respectively.

At September 30, 2011, the Partnership had approximately \$4.9 million of unrecognized compensation expense related to unvested phantom units outstanding under the LTIPs based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 2.2 years.

*Partnership Unit Options.* At September 30, 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 September 30, 2011, all unit options were exercised.

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

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2011		2010		2011		2010	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	–	\$ –	100,000	\$ 6.24	75,000	\$ 6.24	100,000	\$ 6.24
Exercised <sup>(1)</sup>	–	–	(3,000)	6.24	(75,000)	6.24	(3,000)	6.24
Outstanding, end of period <sup>(2)(3)</sup>	–	\$ –	97,000	\$ 6.24	–	\$ –	97,000	\$ 6.24
Options exercisable, end of period <sup>(4)</sup>	–	\$ –	22,000	\$ 6.24	–	\$ –	22,000	\$ 6.24
Non-cash compensation expense recognized (in thousands) <sup>(5)</sup>		\$ –		\$ 1		\$ 3		\$ 3

- (1) The intrinsic value for option unit awards exercised during the three months ended September 2010 was \$0.1 million. The intrinsic values for option unit awards exercised during the nine months ended September 30, 2011 and 2010 were \$1.8 million and \$0.1 million, respectively. Approximately \$19 thousand was received from exercise of unit option awards during the three months ended September 30, 2010. Approximately \$468 thousand and \$19 thousand were received from exercise of unit option awards during the nine months ended September 30, 2011 and 2010, respectively.
- (2) The weighted average remaining contractual life for outstanding and exercisable options at September 30, 2010 was 8.3 years.
- (3) The aggregate intrinsic value of options outstanding at September 30, 2010 was \$1.1 million.
- (4) The aggregate intrinsic value of options exercisable at September 30, 2010 was \$249 thousand.
- (5) Non-cash compensation expense for the nine months ended September 30, 2011 includes incremental compensation expense of \$2 thousand, related to the accelerated vesting of options held by the CEO of the General Partner.

#### *Employee Incentive Compensation Plan and Agreement*

A wholly-owned subsidiary of the Partnership has an incentive plan (the "Cash Plan"), which allows for equity-indexed cash incentive awards to employees of the Partnership (the "Participants"). The Cash Plan is administered by a committee appointed by the CEO of the General Partner. Under the Cash Plan, cash bonus units may be awarded to Participants at the

discretion of the committee. During 2009, the committee granted 375,000 bonus units ("Bonus Units"). A Bonus Unit entitles the employee to receive the cash equivalent of the then-fair market value of a common limited partner unit, without payment of an exercise price, upon vesting of the Bonus Unit. Bonus Units vest ratably over a three year period from the date of grant and will automatically vest upon a change of control, death, or termination without cause, each as defined in the governing document. Vesting will terminate upon termination of employment with cause. In conjunction with the approval of the 2010 LTIP, the holders of 300,000 of the then outstanding 375,000 Bonus Units agreed to exchange their Bonus Units for phantom units, during the nine months ended September 30, 2010.

At September 30, 2011, the Partnership had 25,500 outstanding Bonus Units, which will all vest within the following twelve months. The Partnership recognizes compensation expense related to these awards based upon the fair value, which is re-measured each reporting period based upon the current fair value of the underlying common units. The Partnership recognized compensation expense related to the re-measurement of the outstanding Bonus Units of \$9 thousand and \$0.3 million during the three months ended September 30, 2011 and 2010, respectively, and expense of \$0.6 million during the nine months ended September 30, 2011 and a credit of \$0.5 million during the nine months ended September 30, 2010, which was recorded within general and administrative expense on its consolidated statements of operations. The Partnership had \$0.6 million and \$0.8 million, at September 30, 2011 and December 31, 2010, respectively, included within accrued liabilities on its consolidated balance sheet with regard to these awards, which represents their fair value as of those dates.

## Cash Distributions

9 Months Ended

Sep. 30, 2011

[Cash Distributions](#)

[\[Abstract\]](#)

[Cash Distributions](#)

### NOTE 6 – CASH DISTRIBUTIONS

The Partnership is required to distribute, within 45 days after the end of each quarter, all its available cash (as defined in its partnership agreement) for that quarter to its common unitholders and the General Partner. If common unit distributions in any quarter exceed specified target levels, the General Partner will receive between 15% and 50% of such distributions in excess of the specified target levels. Common unit and General Partner distributions declared by the Partnership from January 1, 2010 through September 30, 2011 were as follows:

<u>For Quarter Ended</u>	<u>Date Cash Distribution Paid</u>	<u>Cash Distribution Per Common Limited Partner Unit</u>	<u>Total Cash Distribution to Common Limited Partners</u> (in thousands)	<u>Total Cash Distribution to the General Partner</u> (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
March 31, 2011	May 13, 2011	0.40	21,400	439
June 30, 2011	August 12, 2011	0.47	25,184	967

On October 26, 2011, the Partnership declared a cash distribution of \$0.54 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2011. The \$30.8 million distribution, including \$1.8 million to the General Partner for its general partner interest and incentive distribution rights, will be paid on November 14, 2011 to unitholders of record at the close of business on November 7, 2011.

Supplemental Condensed  
Consolidating Financial  
Information

9 Months Ended

Sep. 30, 2011

[Supplemental Condensed  
Consolidating Financial  
Information \[Abstract\]  
Supplemental Condensed  
Consolidating Financial  
Information](#)

**NOTE 16 – SUPPLEMENTAL CONDENSED CONSOLIDATING FINANCIAL INFORMATION**

The Partnership's 8.75% Senior Notes and revolving credit facility are guaranteed by its wholly-owned subsidiaries. The guarantees are full, unconditional, joint and several. The Partnership's consolidated financial statements as of September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 2011 and 2010 include the financial statements of Atlas Pipeline Mid-Continent WestOk, LLC ("WestOK LLC") and Atlas Pipeline Mid-Continent WestTex, LLC ("WestTX LLC"), entities in which the Partnership has 95% interests. Under the terms of the 8.75% Senior Notes and the revolving credit facility, WestOK LLC and WestTX LLC are non-guarantor subsidiaries as they are not wholly-owned by the Partnership. The following supplemental condensed consolidating financial information reflects the Partnership's stand-alone accounts, the combined accounts of the guarantor subsidiaries, the combined accounts of the non-guarantor subsidiaries, the consolidating adjustments and eliminations and the Partnership's consolidated accounts as of September 30, 2011 and December 31, 2010 and for the three and nine months ended September 30, 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):

<b>Balance Sheets</b>					
<b>September 30, 2011</b>	<b>Parent</b>	<b>Guarantor Subsidiaries</b>	<b>Non- Guarantor Subsidiaries</b>	<b>Consolidating Adjustments</b>	<b>Consolidated</b>
<b>Assets</b>					
Cash and cash equivalents	\$ –	\$ 167	\$ –	\$ –	\$ 167
Accounts receivable – affiliates	211,201	52,538	–	(263,739)	–
Other current assets	255	50,239	104,789	(1,109)	154,174
Total current assets	211,456	102,944	104,789	(264,848)	154,341
Property, plant and equipment, net	–	264,239	1,217,202	–	1,481,441
Intangible assets, net	–	–	109,052	–	109,052
Investment in joint venture	–	86,688	–	–	86,688
Long term portion of derivative asset	–	26,950	–	–	26,950
Long term notes receivable	–	–	1,852,928	(1,852,928)	–
Equity investments	1,459,815	2,052,644	–	(3,512,459)	–
Other assets, net	19,116	1,773	952	–	21,841
Total assets	<u>\$ 1,690,387</u>	<u>\$ 2,535,238</u>	<u>\$ 3,284,923</u>	<u>\$ (5,630,235)</u>	<u>\$ 1,880,313</u>
<b>Liabilities and Equity</b>					
Accounts payable – affiliates	\$ –	\$ –	\$ 266,415	\$ (263,739)	\$ 2,676
Other current liabilities	5,670	42,355	135,240	–	183,265
Total current liabilities	5,670	42,355	401,655	(263,739)	185,941
Long-term debt, less current portion	414,322	–	9,605	–	423,927
Other long-term liability	77	50	–	–	127
Equity	1,270,318	2,492,833	2,873,663	(5,366,496)	1,270,318
Total liabilities and equity	<u>\$ 1,690,387</u>	<u>\$ 2,535,238</u>	<u>\$ 3,284,923</u>	<u>\$ (5,630,235)</u>	<u>\$ 1,880,313</u>
<b>December 31, 2010</b>					
<b>Assets</b>					
Cash and cash equivalents	\$ –	\$ 164	\$ –	\$ –	\$ 164
Accounts receivable – affiliates	1,329,448	–	–	(1,329,448)	–
Other current assets	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

Long term 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
Total assets	<u>\$ 1,608,980</u>	<u>\$ (209,578)</u>	<u>\$ 3,167,092</u>	<u>\$ (2,801,646)</u>	<u>\$ 1,764,848</u>

#### 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
Total liabilities and equity	<u>\$ 1,608,980</u>	<u>\$ (209,578)</u>	<u>\$ 3,167,092</u>	<u>\$ (2,801,646)</u>	<u>\$ 1,764,848</u>

#### Statements of Operations

	Parent	Guarantor Subsidiaries	Non- Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
<b>Three Months Ended September 30, 2011</b>					
Total revenue and other income (loss), net	\$ –	\$ 95,458	\$ 284,322	\$ –	\$ 379,780
Total costs and expenses	(3,857)	(81,241)	(246,209)	–	(331,307)
Equity income	53,613	40,460	–	(92,288)	1,785
Net income (loss)	<u>\$ 49,756</u>	<u>\$ 54,677</u>	<u>\$ 38,113</u>	<u>\$ (92,288)</u>	<u>\$ 50,258</u>

#### Three Months Ended September 30, 2010<sup>(1)</sup>

Total revenue and other income (loss), net	\$ –	\$ 36,959	\$ 189,159	\$ –	\$ 226,118
Total costs and expenses	(11,047)	(67,485)	(162,471)	–	(241,003)
Equity income	294,137	29,017	–	(321,367)	1,787
Loss on early extinguishment of debt	–	(4,359)	–	–	(4,359)
Income (loss) from continuing operations	283,090	(5,868)	26,688	(321,367)	(17,457)
Income from discontinued operations	–	305,927	–	–	305,927
Net income (loss)	<u>\$ 283,090</u>	<u>\$ 300,059</u>	<u>\$ 26,688</u>	<u>\$ (321,367)</u>	<u>\$ 288,470</u>

#### Nine Months Ended September 30, 2011

Total revenue and other income (loss), net	\$ –	\$ 202,637	\$ 784,191	\$ –	\$ 986,828
Total costs and expenses	(19,661)	(221,578)	(683,891)	–	(925,130)
Equity income	337,728	103,357	–	(438,151)	2,934
Gain on asset sales and other	–	255,674	–	–	255,674
Loss on early extinguishment of debt	(19,574)	–	–	–	(19,574)
Income (loss) from continuing operations	298,493	340,090	100,300	(438,151)	300,732
Loss from discontinued operations	–	(81)	–	–	(81)
Net income (loss)	<u>\$ 298,493</u>	<u>\$ 340,009</u>	<u>\$ 100,300</u>	<u>\$ (438,151)</u>	<u>\$ 300,651</u>

#### Nine Months Ended September 30, 2010<sup>(1)</sup>

Total revenue and other income (loss), net	\$ –	\$ 123,513	\$ 558,985	\$ –	\$ 682,498
Total costs and expenses	(32,951)	(200,806)	(478,204)	–	(711,961)
Equity income	316,616	84,488	–	(396,967)	4,137
Loss on early extinguishment of debt	–	(4,359)	–	–	(4,359)
Income (loss) from continuing operations	283,665	2,836	80,781	(396,967)	(29,685)
Income from discontinued operations	–	320,684	–	–	320,684
Net income (loss)	<u>\$ 283,665</u>	<u>\$ 323,520</u>	<u>\$ 80,781</u>	<u>\$ (396,967)</u>	<u>\$ 290,999</u>



**Statements of Cash Flows**

	<b>Parent</b>	<b>Guarantor Subsidiaries</b>	<b>Non- Guarantor Subsidiaries</b>	<b>Consolidating Adjustments</b>	<b>Consolidated</b>
<b><u>Nine Months Ended September 30, 2011</u></b>					
Net cash provided by (used in):					
Total operating activities	\$ (21,998)	\$ 34,831	\$ 164,961	\$ (97,136)	\$ 80,658
Continuing investing activities	268,195	292,617	(123,226)	(271,511)	166,075
Discontinued investing activities	–	(81)	–	–	(81)
Total investing activities	<u>268,195</u>	<u>292,536</u>	<u>(123,226)</u>	<u>(271,511)</u>	<u>165,994</u>
Total financing activities	<u>(246,197)</u>	<u>(327,364)</u>	<u>(41,735)</u>	<u>368,647</u>	<u>(246,649)</u>
Net change in cash and cash equivalents	–	3	–	–	3
Cash and cash equivalents, beginning of period	<u>–</u>	<u>164</u>	<u>–</u>	<u>–</u>	<u>164</u>
Cash and cash equivalents, end of period	<u>\$ –</u>	<u>\$ 167</u>	<u>\$ –</u>	<u>\$ –</u>	<u>\$ 167</u>
<b><u>Nine Months Ended September 30, 2010</u></b>					
Net cash provided by (used in):					
Continuing operating activities	\$ 361,840	\$ 15,291	\$ 144,031	\$ (444,367)	\$ 76,795
Discontinued operating activities	–	24,490	–	–	24,490
Total operating activities	<u>361,840</u>	<u>39,781</u>	<u>144,031</u>	<u>(444,367)</u>	<u>101,285</u>
Continuing investing activities	370,097	861,369	(26,580)	(1,242,603)	(37,717)
Discontinued investing activities	–	667,605	–	–	667,605
Total investing activities	<u>370,097</u>	<u>1,528,974</u>	<u>(26,580)</u>	<u>(1,242,603)</u>	<u>629,888</u>
Total financing activities	<u>(731,937)</u>	<u>(1,569,610)</u>	<u>(117,451)</u>	<u>1,686,970</u>	<u>(732,028)</u>
Net change in cash and cash equivalents	–	(855)	–	–	(855)
Cash and cash equivalents, beginning of period	<u>–</u>	<u>1,021</u>	<u>–</u>	<u>–</u>	<u>1,021</u>
Cash and cash equivalents, end of period	<u>\$ –</u>	<u>\$ 166</u>	<u>\$ –</u>	<u>\$ –</u>	<u>\$ 166</u>

(1) Restated to reflect the reclass of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

**Consolidated Statements Of  
Cash Flows (USD \$)  
In Thousands**

**9 Months Ended  
Sep. 30, Sep. 30,  
2011 2010**

**CASH FLOWS FROM OPERATING ACTIVITIES:**

<u>Net income</u>	\$ 300,651	\$ 290,999
<u>Less: Income (loss) from discontinued operations</u>	(81)	320,684
<u>Net income (loss) from continuing operations</u>	300,732	(29,685)

**Adjustments to reconcile net income (loss) from continuing operations to net cash provided by operating activities:**

<u>Depreciation and amortization</u>	57,499	55,647
<u>Equity income in joint ventures</u>	(2,934)	(4,137)
<u>Distributions received from joint ventures</u>	2,548	8,276
<u>Non-cash compensation expense</u>	2,507	2,810
<u>Amortization of deferred finance costs</u>	3,354	4,729
<u>Gain on asset sales</u>	(255,674)	0
<u>Loss on early extinguishment of debt</u>	19,574	4,359

**Change in operating assets and liabilities:**

<u>Accounts receivable, prepaid expenses and other</u>	(18,950)	19,106
<u>Accounts payable and accrued liabilities</u>	25,497	11,431
<u>Accounts payable and accounts receivable - affiliates</u>	(9,604)	8,348
<u>Derivative accounts payable and receivable</u>	(43,891)	(4,089)
<u>Net cash provided by continuing operating activities</u>	80,658	76,795
<u>Net cash provided by discontinued operating activities</u>	0	24,490
<u>Net cash provided by operating activities</u>	80,658	101,285

**CASH FLOWS FROM INVESTING ACTIVITIES:**

<u>Capital contribution to equity investment</u>	(12,250)	(6,914)
<u>Capital expenditures</u>	(148,144)	(31,194)
<u>Acquisition of equity investment</u>	(85,000)	0
<u>Net proceeds related to asset sales</u>	411,480	0
<u>Other</u>	(11)	391
<u>Net cash provided by (used in) continuing investing activities</u>	166,075	(37,717)
<u>Net cash provided by (used in) discontinued investing activities</u>	(81)	667,605
<u>Net cash provided by investing activities</u>	165,994	629,888

**CASH FLOWS FROM FINANCING ACTIVITIES:**

<u>Borrowings under credit facility</u>	995,500	273,000
<u>Repayments under credit facility</u>	(867,000)	(587,000)
<u>Repayment of debt</u>	(279,557)	(433,504)
<u>Payment of premium on early retirement of debt</u>	(14,342)	0
<u>Principal payments on capital lease</u>	(452)	(92)
<u>Net proceeds from issuance of common limited partner units</u>	468	15,319
<u>Purchase and retirement of treasury units</u>	(984)	0
<u>Net proceeds from issuance of preferred limited partner units</u>	0	8,000
<u>Redemption of preferred limited partner units</u>	(8,000)	0

<u>Net distributions to non-controlling interest holders</u>	(1,820)	(4,125)
<u>Distributions paid to common limited partners, the General Partner and preferred limited partners</u>	(69,302)	0
<u>Other</u>	(1,160)	(3,626)
<u>Net cash used in financing activities</u>	(246,649)	(732,028)
<u>Net change in cash and cash equivalents</u>	3	(855)
<u>Cash and cash equivalents, beginning of period</u>	164	1,021
<u>Cash and cash equivalents, end of period</u>	\$ 167	\$ 166

**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 6.3% and 7.7% for the three months ended September 30, 2011 and 2010, respectively, and 7.2% and 7.5% for the nine months ended September 30, 2011 and 2010, respectively. The amount of interest capitalized was \$1.7 million and \$0.2 million for the three months ended September 30, 2011 and 2010, respectively, and \$3.0 million and \$0.6 million for the nine months ended September 30, 2011 and 2010, respectively.

*Capital Leases*

Leased property and equipment meeting capital lease criteria are capitalized based on the minimum payments required under the lease and are included within property plant and equipment on the Partnership's consolidated balance sheets. Obligations under capital leases are accounted for as current and noncurrent liabilities and are included within debt on the Partnership's consolidated balance sheets. Amortization is calculated on a straight-line method based upon the estimated useful lives of the assets.

*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 September 30, 2011 and December 31, 2010 (in thousands):

	<u>September 30,</u> <u>2011</u>	<u>December</u> <u>31,</u> <u>2010</u>	<u>Estimated</u> <u>Useful</u> <u>Lives</u> <u>In Years</u>
<b>Customer relationships:</b>			
Gross carrying amount	\$ 205,313	\$ 205,313	7–10
Accumulated amortization	(96,261)	(78,934)	
Net carrying amount	<u>\$ 109,052</u>	<u>\$ 126,379</u>	

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. The weighted-average amortization period for customer relationships is 9.1 years. The Partnership recorded amortization expense on intangible assets of \$5.8 million for both the three months ended September 30, 2011 and 2010, and \$17.3 million for both the nine months ended September 30, 2011 and 2010 on its consolidated statements of operations. Amortization expense related to intangible assets is estimated to be as follows for each of the next five calendar years: 2011 to 2013 - \$23.1 million per year; 2014 - \$19.5 million; 2015 - \$14.5 million.

*Stock-Based Compensation*

All share-based payments to employees, including grants of employee stock options, are recognized in the financial statements based on their fair values. Share-based awards, which have a cash option, are classified as liabilities on the Partnership's consolidated balance sheets. All other share-based awards are classified as equity on the Partnership's consolidated balance sheets. Compensation expense associated with share-based payments is recognized within general and administrative expenses on the Partnership's statements of operations from the date of the grant through the date

of vesting, amortized on a straight-line method. Generally, no expense is recorded for awards that do not vest due to forfeiture.

#### *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 6), with a priority allocation of net income to the General Partner's incentive distributions, if any, in accordance with the partnership agreement, and the remaining net income (loss) allocated with respect to the General Partner's and limited partners' ownership interests.

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

Unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and are included in the computation of earnings per unit pursuant to the two-class method. The Partnership's phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plans and incentive compensation agreements (see Note 13), 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		Nine Months Ended	
	September 30,		September 30,	
	2011	2010	2011	2010
<b>Continuing operations:</b>				
Net income (loss)	\$ 50,258	\$ (17,457)	\$ 300,732	\$ (29,685)
Income attributable to non-controlling interest	(1,760)	(1,076)	(4,492)	(3,338)
Preferred unit dividends	—	(240)	(389)	(240)
Net income (loss) attributable to common limited partners and the General Partner	48,498	(18,773)	295,851	(33,263)
General Partner's cash incentive distributions paid	441	—	441	—
General Partner's ownership interest	966	(358)	5,938	(636)
Net income (loss) attributable to the General Partner's ownership interests	1,407	(358)	6,379	(636)
Net income (loss) attributable to common limited partners	47,091	(18,415)	289,472	(32,627)
Net income attributable to participating securities – phantom units <sup>(1)</sup>	369	—	2,301	—
Net income (loss) utilized in the calculation of net income (loss) from continuing operations attributable to common limited partners per unit	\$ 46,722	\$ (18,415)	\$ 287,171	\$ (32,627)
<b>Discontinued operations:</b>				
Net income (loss)	\$ —	\$ 305,927	\$ (81)	\$ 320,684

Net income (loss) attributable to the General Partner's ownership interests	—	5,842	(2)	6,125
Net income (loss) utilized in the calculation of net income from discontinued operations attributable to common limited partners per unit	\$ —	\$ 300,085	\$ (79)	\$ 314,559

(1) Net income attributable to common limited partners' ownership interest is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three and nine months ended September 30, 2010, net loss attributable to common limited partners' ownership interest is not allocated to approximately 532,000 and 234,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, plus income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding plus the dilutive effect of outstanding participating securities and unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership's long-term incentive plans (see Note 13).

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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Weighted average number of common limited partner units – basic	53,588	53,277	53,494	53,115
Add effect of participating securities – phantom units <sup>(1)</sup> ...	424	—	429	—
Add effect of dilutive option incentive awards <sup>(2)</sup>	—	—	—	—
Weighted average common limited partner units – diluted	<u>54,012</u>	<u>53,277</u>	<u>53,923</u>	<u>53,115</u>

(1) For the three and nine months ended September 30, 2010, approximately 532,000 and 234,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such phantom units would have been anti-dilutive.

(2) For the three and nine months ended September 30, 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. There were no unit options outstanding for the three and nine months ended September 30, 2011.

### Comprehensive Income

Comprehensive income 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" 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 9). The following table sets forth the calculation of the Partnership's comprehensive income (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Net income	\$ 50,258	\$ 288,470	\$ 300,651	\$ 290,999
Income attributable to non-controlling interests	(1,760)	(1,076)	(4,492)	(3,338)
Preferred unit dividends	—	(240)	(389)	(240)
Net income attributable to common limited partners and the General Partner	<u>48,498</u>	<u>287,154</u>	<u>295,770</u>	<u>287,421</u>

Other comprehensive income:

Adjustment for realized losses on derivatives reclassified to net income	1,714	14,122	5,118	35,555
Comprehensive income	<u>\$ 50,212</u>	<u>\$ 301,276</u>	<u>\$ 300,888</u>	<u>\$ 322,976</u>

### Revenue Recognition

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

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

*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 the Partnership paid for the unprocessed natural gas. In order to help mitigate the risk associated with Keep-Whole contracts the Partnership generally imposes a fee to gather the gas that is settled under this arrangement. Also, because the natural gas volumes contracted under some Keep-Whole agreements is 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 September 30, 2011 and December 31, 2010 of \$66.1 million and \$57.8 million, respectively, which are included in accounts receivable within its consolidated balance sheets.

### Recently Issued Accounting Standards

In May 2011, the FASB issued Accounting Standards Update ("ASU") 2011-04, "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," which, among other changes, requires (1) additional disclosures for fair value measurements categorized within Level 2 and Level 3 of the fair value hierarchy; and (2) additional disclosures for items not measured at fair value in the Partnership's consolidated balance sheets but for which the fair value is required to be disclosed. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. Early adoption is prohibited. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and results of operations.

In June 2011, the FASB issued ASU 2011-05, "Comprehensive Income (Topic 220) – Presentation of Comprehensive Income," which, among other changes, eliminates the option to present components of other comprehensive income as part of the statement of changes in equity. The amendments in this update require "all nonowner changes in equity be presented either in a single continuous statement of comprehensive income or in two separate but consecutive statements." The update does not change the components of comprehensive income that must be presented. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. Early adoption is permitted. The Partnership will apply these requirements upon the adoption of this ASU on January 1, 2012. The Partnership does not expect the adoption to have a material impact on its financial position and results of operations.

## Debt

9 Months Ended  
Sep. 30, 2011

[Debt \[Abstract\]](#)

[Debt](#)

### NOTE 11 — DEBT

Total debt consists of the following (in thousands):

	September 30, 2011	December 31, 2010
Revolving credit facility	\$ 198,500	\$ 70,000
8.125% Senior notes – due 2015	–	272,181
8.75% Senior notes – due 2018	215,822	223,050
Capital lease obligations	11,659	743
Total debt	425,981	565,974
Less current maturities	(2,054)	(210)
Total long term debt	\$ 423,927	\$ 565,764

Cash payments for interest related to debt, excluding payments related to early retirement of debt and net of capitalized interest, were \$3 thousand and \$11.4 million for the three months ended September 30, 2011 and 2010, respectively, and \$17.2 million and \$65.9 million for the nine months ended September 30, 2011 and 2010, respectively.

#### *Revolving Credit Facility*

At September 30, 2011, the Partnership had a \$450.0 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 weighted average interest rate for borrowings on the revolving credit facility, at September 30, 2011, was 3.2%. Up to \$50.0 million of the revolving credit facility may be utilized for letters of credit, of which \$1.1 million was outstanding at September 30, 2011. These outstanding letter of credit amounts were not reflected as borrowings on the Partnership's consolidated balance sheets. At September 30, 2011, the Partnership had \$250.4 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 the Partnership's property and that of its subsidiaries, except for the assets owned by WestOK and WestTX joint ventures; and by the guaranty of each of the Partnership's consolidated subsidiaries other than the joint venture companies. The revolving credit facility contains customary covenants, including 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 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 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 September 30, 2011, the Partnership was in compliance with all covenants under the revolving credit facility.

### *Senior Notes*

At September 30, 2011, the Partnership had \$215.8 million principal amount outstanding of 8.75% senior unsecured notes due on June 15, 2018 ("8.75% Senior Notes"). Interest on the 8.75% Senior Notes is payable semi-annually in arrears on June 15 and December 15. The 8.75% Senior Notes are redeemable at any time after June 15, 2013, at certain redemption prices, together with accrued and unpaid interest to the date of redemption. The 8.75% Senior Notes are subject to repurchase by the Partnership at a price equal to 101% of their principal amount, plus accrued and unpaid interest, upon a change of control or upon certain asset sales if the Partnership does not reinvest the net proceeds within 360 days. The 8.75% Senior Notes are junior in right of payment to the Partnership's secured debt, including the Partnership's obligations under its revolving credit facility.

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

The indenture governing the 8.75% Senior Notes contains covenants, including limitations of the Partnership's ability to: incur certain liens; engage in sale/leaseback transactions; incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all its assets. The Partnership is in compliance with these covenants as of September 30, 2011.

On April 8, 2011, the Partnership redeemed all of the 8.125% senior unsecured notes due on December 15, 2015 ("8.125% Senior Notes"). The redemption price was determined in accordance with the indenture for the 8.125% Senior Notes, plus accrued and unpaid interest thereon to the redemption date. The Partnership paid \$293.7 million to redeem the \$275.5 million principal plus \$11.2 million premium and \$7.0 million accrued interest. There were no 8.125% Senior Notes outstanding at September 30, 2011.

### *Capital Leases*

On July 15, 2011, the Partnership amended an operating lease for eight natural gas compressors to include a mandatory purchase of the equipment at the end of the lease term, thereby converting the agreement to a capital lease upon the effective date of the amendment. As a result, the Partnership recorded an asset of \$11.4 million within property, plant and equipment and recorded an offsetting liability within long term debt on the Partnership's consolidated balance sheets. This amount was based on the minimum payments required under the lease and the Partnership's incremental borrowing rate. During the nine months ended September 30, 2010, the Partnership entered into capital lease arrangements having obligations of \$0.9 million at inception, which were recorded within property, plant and equipment with an offsetting liability recorded within long term debt on the Partnership's consolidated balance sheets.

The following is a summary of the leased property under capital leases, which are included within property, plant and equipment (see Note 7) (in thousands):

	<b>September 30, 2011</b>	<b>December 31, 2010</b>
Pipelines, processing and compression facilities.	\$ 12,507	\$ 1,139
Less – accumulated depreciation	(185)	(47)
	<u>\$ 12,322</u>	<u>\$ 1,092</u>

Amortization expense for leased properties was \$109 thousand and \$14 thousand for the three months ended September 30, 2011 and 2010, respectively, and \$137 thousand and \$33 thousand for the nine months ended September 30, 2011 and 2010, respectively, which is included within depreciation and amortization expense on the Partnership's consolidated statements of operations (see Note 7).

As of September 30, 2011, future minimum lease payments related to the capital leases are as follows (in thousands):

	<b>Capital Lease Minimum Payments</b>
2011	\$ 671
2012	2,685
2013	9,376
2014	64
2015	–
Thereafter	–
Total minimum lease payments	<u>12,796</u>
Less amounts representing interest	<u>(1,137)</u>
Present value of minimum lease payments	11,659
Less current capital lease obligations	<u>(2,054)</u>
Long-term capital lease obligations	<u>\$ 9,605</u>

## Segment Information

9 Months Ended

Sep. 30, 2011

[Segment Information](#)

[\[Abstract\]](#)

[Segment Information](#)

### NOTE 15 — SEGMENT INFORMATION

On February 17, 2011, the Partnership sold its 49% interest in Laurel Mountain, which was reported as part of the Partnership's previous Appalachia segment (see Note 3). On May 11, 2011, the Partnership acquired a 20% interest in WTLPG (see Note 3). As a result of these two transactions, the Partnership realigned the reportable segments into two new segments: Gathering and Processing; and Pipeline Transportation ("Pipeline"). These reportable segments reflect the way the Partnership will manage its operations going forward. The Partnership has adjusted its segment presentation from the amounts previously presented to reflect the realignment of the segments.

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

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

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

	<b>Gathering and Processing</b>	<b>Pipeline</b>	<b>Corporate and Other</b>	<b>Consolidated</b>
<b>Three Months Ended September 30, 2011:</b>				
<b>Revenue:</b>				
Revenues – third party <sup>(1)</sup>	\$ 357,655	\$ –	\$ 22,046	\$ 379,701
Revenues – affiliates	79	–	–	79
Total revenue and other income (loss), net	<u>357,734</u>	<u>–</u>	<u>22,046</u>	<u>379,780</u>
<b>Costs and Expenses:</b>				
Operating costs and expenses	296,615	129	–	296,744
General and administrative <sup>(1)</sup>	–	–	9,149	9,149
Other costs	–	8	–	8
Depreciation and amortization	19,471	–	–	19,471
Interest expense <sup>(1)</sup>	–	–	5,935	5,935
Total costs and expenses	<u>316,086</u>	<u>137</u>	<u>15,084</u>	<u>331,307</u>
Equity income	–	1,785	–	1,785
Net income	<u>\$ 41,648</u>	<u>\$ 1,648</u>	<u>\$ 6,962</u>	<u>\$ 50,258</u>
<b>Three Months Ended September 30, 2010<sup>(2)</sup>:</b>				
<b>Revenue:</b>				
Revenues – third party <sup>(1)</sup>	\$ 235,190	\$ –	\$ (9,213)	\$ 225,977
Revenues – affiliates	141	–	–	141
Total revenue and other income (loss), net	<u>235,331</u>	<u>–</u>	<u>(9,213)</u>	<u>226,118</u>
<b>Costs and expenses:</b>				
Operating costs and expenses	191,772	–	–	191,772
General and administrative <sup>(1)</sup>	–	–	7,578	7,578
Depreciation and amortization	18,566	–	–	18,566
Interest expense <sup>(1)</sup>	–	–	23,087	23,087

Total costs and expenses	210,338	–	30,665	241,003
Equity income	1,787	–	–	1,787
Loss on early extinguishment of debt	–	–	(4,359)	(4,359)
Net income (loss) from continuing operations	26,780	–	(44,237)	(17,457)
Income from discontinued operations	–	–	305,927	305,927
Net income	\$ 26,780	\$ –	\$ 261,690	\$ 288,470

	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
<b>Nine Months Ended September 30, 2011:</b>				
<b>Revenue:</b>				
Revenues – third party <sup>(1)</sup>	\$ 982,739	\$ –	\$ 3,833	\$ 986,572
Revenues – affiliates	256	–	–	256
Total revenue and other income (loss), net	982,995	–	3,833	986,828
<b>Costs and expenses:</b>				
Operating costs and expenses	815,573	129	–	815,702
General and administrative <sup>(1)</sup>	–	–	26,821	26,821
Other costs	–	583	–	583
Depreciation and amortization	57,499	–	–	57,499
Interest expense <sup>(1)</sup>	–	–	24,525	24,525
Total costs and expenses	873,072	712	51,346	925,130
Equity income	462	2,472	–	2,934
Gain on sale of assets	255,674	–	–	255,674
Loss on early extinguishment of debt	–	–	(19,574)	(19,574)
Net income (loss) from continuing operations	366,059	1,760	(67,087)	300,732
Loss from discontinued operations	–	–	(81)	(81)
Net income (loss)	\$ 366,059	\$ 1,760	\$ (67,168)	\$ 300,651

**Nine Months Ended September 30,  
2010<sup>(2)</sup>:**

<b>Revenue:</b>				
Revenues – third party <sup>(1)</sup>	\$ 692,052	\$ –	\$ (10,026)	\$ 682,026
Revenues – affiliates	472	–	–	472
Total revenue and other income (loss), net	692,524	–	(10,026)	682,498
<b>Costs and Expenses:</b>				
Operating costs and expenses	558,708	–	–	558,708
General and administrative <sup>(1)</sup>	–	–	23,521	23,521
Depreciation and amortization	55,647	–	–	55,647
Interest expense <sup>(1)</sup>	–	–	74,085	74,085
Total costs and expenses	614,355	–	97,606	711,961
Equity income	4,137	–	–	4,137
Loss on early extinguishment of debt	–	–	(4,359)	(4,359)
Net income (loss) from continuing operations	82,306	–	(111,991)	(29,685)
Income from discontinued operations	–	–	320,684	320,684
Net income	\$ 82,306	\$ –	\$ 208,693	\$ 290,999

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010 <sup>(2)</sup>	2011	2010 <sup>(2)</sup>
<b>Capital Expenditures:</b>				
Gathering and Processing	\$ 56,175	\$ 11,340	\$ 148,144	\$ 32,078
Pipeline	–	–	–	–
	\$ 56,175	\$ 11,340	\$ 148,144	\$ 32,078

<b>Balance Sheet</b>	<b>September 30, 2011</b>	<b>December 31, 2010</b>
<b>Investment in joint ventures:</b>		
Gathering and Processing	\$ —	\$ 153,358
Pipeline	86,688	—
	<u>\$ 86,688</u>	<u>\$ 153,358</u>
<b>Total assets:</b>		
Gathering and Processing	\$ 1,735,445	\$ 1,738,493
Pipeline	86,915	—
Corporate other	57,953	26,355
	<u>\$ 1,880,313</u>	<u>\$ 1,764,848</u>

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

<b>Natural gas and liquids:</b>	<b>Three Months Ended</b>		<b>Nine Months Ended</b>	
	<b>September 30,</b>		<b>September 30,</b>	
	<b>2011</b>	<b>2010</b>	<b>2011</b>	<b>2010</b>
Natural gas	\$ 112,909	\$ 72,421	\$ 299,566	\$ 226,806
NGLs	209,941	134,294	582,806	383,962
Condensate	19,070	12,526	56,268	30,895
Other	(422)	1,237	(665)	315
Total	<u>\$ 341,498</u>	<u>\$ 220,478</u>	<u>\$ 937,975</u>	<u>\$ 641,978</u>

- (1) The Partnership notes derivative contracts are carried at the corporate level and interest and general and administrative expenses have not been allocated to its reportable segments as it would be unfeasible to reasonably do so for the periods presented.
- (2) Restated to reflect the realignment of the segments due to the sale of Laurel Mountain and the acquisition of WTLPG (see Note 3) and to reflect the reclass of accelerated amortization of deferred financing costs from interest expense to loss on early extinguishment of debt (see Note 1).

**Consolidated Balance Sheets****(USD \$)****Sep. 30, 2011 Dec. 31, 2010****In Thousands****ASSETS**

<u>Cash and cash equivalents</u>	\$ 167	\$ 164
<u>Accounts receivable</u>	117,978	99,759
<u>Notes receivable</u>	8,500	0
<u>Current portion of derivative assets</u>	11,887	0
<u>Prepaid expenses and other</u>	15,809	15,118
<u>Total current assets</u>	154,341	115,041
<u>Property, plant and equipment, net</u>	1,481,441	1,341,002
<u>Intangible assets, net</u>	109,052	126,379
<u>Investment in joint ventures</u>	86,688	153,358
<u>Long-term portion of derivative assets</u>	26,950	0
<u>Other assets, net</u>	21,841	29,068
<u>Total assets</u>	1,880,313	1,764,848

**LIABILITIES AND EQUITY**

<u>Current portion of long-term debt</u>	2,054	210
<u>Accounts payable affiliates</u>	2,676	12,280
<u>Accounts payable</u>	45,279	29,382
<u>Accrued liabilities</u>	40,378	30,013
<u>Accrued interest payable</u>	5,896	1,921
<u>Current portion of derivative liabilities</u>	0	4,564
<u>Accrued producer liabilities</u>	89,658	72,996
<u>Distribution payable</u>	0	240
<u>Total current liabilities</u>	185,941	151,606
<u>Long-term portion of derivative liabilities</u>	0	5,608
<u>Long-term debt, less current portion</u>	423,927	565,764
<u>Other long-term liability</u>	127	223

**Commitments and contingencies****Equity:**

<u>General Partner's interest</u>	24,639	20,066
<u>Class C preferred limited partner's interest</u>	0	8,000
<u>Common limited partners' interests</u>	1,281,650	1,057,342
<u>Accumulated other comprehensive loss</u>	(6,106)	(11,224)
<u>Total partners' capital</u>	1,300,183	1,074,184
<u>Non-controlling interest</u>	(29,865)	(32,537)
<u>Total equity</u>	1,270,318	1,041,647
<u>Total liabilities and equity</u>	\$ 1,880,313	\$ 1,764,848