ATLAS PIPELINE PARTNERS LP
Form 10-Q
November 07, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended 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

ATLAS PIPELINE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

DELAWARE	**23-3011077**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
1550 Coraopolis Heights Road	
Moon Township, Pennsylvania	**15108**
(Address of principal executive office)	**(Zip code)**

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

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

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

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

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

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

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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, 2011	December 31, 2010
ASSETS		
Current assets:		
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
Property, plant and equipment, net	1,481,441	1,341,002
Intangible assets, net	109,052	126,379
Investment in joint ventures	86,688	153,358
Long-term portion of derivative assets	26,950	
Other assets, net	21,841	29,068
Total assets	$ 1,880,313	$ 1,764,848
LIABILITIES AND EQUITY		
Current liabilities:		
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
Long-term portion of derivative liabilities		5,608
Long-term debt, less current portion	423,927	565,764
Other long-term liability	127	223
Commitments and contingencies		
Equity:		
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	1,270,318	1,041,647
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 September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
Revenue:				
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	379,780	226,118	986,828	682,498
Costs and expenses:				
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	331,307	241,003	925,130	711,961
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	50,258	(17,457)	300,732	(29,685)
Discontinued operations:				
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		305,927	(81)	320,684
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	$ 48,498	$ 287,154	$ 295,770	$ 287,421

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ATLAS PIPELINE PARTNERS, L.P. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS (Unaudited)

(in thousands, except per unit data)

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

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 Partner Units							
	Class C Preferred	Common	Class C Preferred Limited Partner	Common Limited Partners	General Partner	Accumulated Other Comprehensive Loss	Non-controlling Interest	Total
Balance at January 1, 2011	8,000	53,338,010	$ 8,000	$ 1,057,342	$ 20,066	$ (11,224)	$ (32,537)	$ 1,041,647
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	Nine Months Ended September 30, 2010
CASH FLOWS FROM OPERATING ACTIVITIES:		
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
CASH FLOWS FROM INVESTING ACTIVITIES:		
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
CASH FLOWS FROM FINANCING ACTIVITIES:		
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	(246,649)	(732,028)
Net change in cash and cash equivalents	3	(855)
Cash and cash equivalents, beginning of period	164	1,021
Cash and cash equivalents, end of period	$ 167	$ 166

See accompanying notes to consolidated financial statements

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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
Customer relationships:			
Gross carrying amount	$ 205,313	$ 205,313	7 10
Accumulated amortization	(96,261)	(78,934)	
Net carrying amount	$ 109,052	$ 126,379	

The Partnership amortizes intangible assets with finite useful lives over their estimated useful lives. If an intangible asset has a finite useful life, but the precise length of that life is not known, that intangible asset must be amortized over the best estimate of its useful life. At a minimum, the Partnership will assess the useful lives of all intangible assets on an annual basis to determine if adjustments are required. The estimated useful life for the Partnership s customer relationship intangible assets is based upon the estimated average length of non-contracted customer relationships in existence at the date of acquisition, adjusted for management s estimate of whether these individual relationships will continue in excess or less than the average length. 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 September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Continuing operations:				
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[(1)]	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)
Discontinued operations:				
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):

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	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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[1]	424		429	
Add effect of dilutive option incentive awards[2]				
Weighted average common limited partner units diluted	54,012	53,277	53,923	53,115

(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, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 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	48,498	287,154	295,770	287,421
Other comprehensive income:				
Adjustment for realized losses on derivatives reclassified to net income	1,714	14,122	5,118	35,555
Comprehensive income	$ 50,212	$ 301,276	$ 300,888	$ 322,976

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 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	$ 86,688	$ 153,358

	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	$ 1,785	$ 1,787	$ 2,934	$ 4,137

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	$	$ 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.

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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For Quarter Ended	Date Cash Distribution Paid	Cash Distribution Per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners (in thousands)	Total Cash Distribution to the General Partner (in thousands)
March 31, 2010	None	$ 0.00	$	$
June 30, 2010	None	0.00		
September 30, 2010	November 14, 2010	0.35	18,660	363
December 31, 2010	February 14, 2011	0.37	19,735	398
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):

	September 30, 2011	December 31, 2010	Estimated Useful Lives in Years
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
	1,707,426	1,527,344	
Less accumulated depreciation	(225,985)	(186,342)	
	$ 1,481,441	$ 1,341,002	

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs are expensed as incurred. Major renewals and improvements that extend the useful lives of property are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset s estimated useful life. The Partnership follows the composite method of depreciation and has determined the composite groups to be the major asset classes of its gathering and processing systems. 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
	$ 21,841	$ 29,068

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):

	September 30, 2011	December 31, 2010
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)	$ 38,837	$ (10,172)

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

Balance Sheet Location	**September 30, 2011**	**December 31, 2010**
Asset Derivatives		
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
Liability Derivatives		
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)
Total Derivatives	$ 38,837	$ (10,172)

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

Production Period	Purchased/ Sold	Commodity	Volumes(1)	Average Fixed Price	Fair Value(2) Asset/ (Liability)
Natural Gas					
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
Natural Gas Liquids					
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
Crude Oil					
2011	Sold	Crude Oil	30	90.75	343
2012	Sold	Crude Oil	180	103.76	4,100
Total Fixed Price Swaps					$ 5,147

Options

Production Period	Purchased/ Sold	Type	Commodity	Volumes(1)	Average Strike Price	Fair Value(2) Asset/ (Liability)
Natural Gas Liquids						
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
Crude Oil						
2011	Purchased	Put	Crude Oil	93	99.45	1,911
2011	Sold	Call	Crude Oil	170	93.35	(208)
2011	Purchased(3)	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(3)	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.

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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):

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

(1) Hedges previously designated as cash flow hedges
(2) Dedesignated 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):

	Level 1	Level 2	Level 3	Total
September 30, 2011				
Assets				
Commodity swaps	$	$ 6,433	$ 2,564	$ 8,997
Commodity options		14,186	22,921	37,107
Total assets		20,619	25,485	46,104
Liabilities				
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
December 31, 2010				
Assets				
Commodity swaps	$	$ 1,225	$ 124	$ 1,349
Commodity options		2,327		2,327
Total assets		3,552	124	3,676
Liabilities				
Commodity swaps		(1,461)	(1,914)	(3,375)
Commodity options		(10,473)		(10,473)
Total liabilities		(11,934)	(1,914)	(13,848)
Total derivatives	$	$ (8,382)	$ (1,790)	$ (10,172)

The Partnership s Level 3 fair value amount relates to its derivative contracts on NGL fixed price swaps and NGL options. The following table provides a summary of changes in fair value of the Partnership s Level 3 derivative instruments for the nine months ended September 30, 2011 (in thousands):

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

(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):

	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

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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)
	$ 12,322	$ 1,092

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):

		Capital Lease Minimum Payments
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	$	9,605

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 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(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)	Number of Units	Fair Value(1)
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(2)	(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(3)(4)	389,765	$ 19.24	496,149	$ 12.43	389,765	$ 19.24	496,149	$ 12.43
Matured and not issued(5)	750	$ 11.12	250	$ 44.51	750	$ 11.12	250	$ 44.51
Non-cash compensation expense recognized (in thousands)(6)		$ 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.

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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(1)			(3,000)	6.24	(75,000)	6.24	(3,000)	6.24
Outstanding, end of period(2)(3)		$	97,000	$ 6.24		$	97,000	$ 6.24
Options exercisable, end of period(4)		$	22,000	$ 6.24		$	22,000	$ 6.24
Non-cash compensation expense recognized (in thousands)(5)		$		$ 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
Three Months Ended September 30, 2011:				
Revenue:				
Revenues third party[1]	$ 357,655	$	$ 22,046	$ 379,701
Revenues affiliates	79			79
Total revenue and other income (loss), net	357,734		22,046	379,780
Costs and Expenses:				
Operating costs and expenses	296,615	129		296,744
General and administrative[1] `			9,149	9,149
Other costs		8		8
Depreciation and amortization	19,471			19,471
Interest expense[1]			5,935	5,935
Total costs and expenses	316,086	137	15,084	331,307
Equity income		1,785		1,785
Net income	$ 41,648	$ 1,648	$ 6,962	$ 50,258
Three Months Ended September 30, 2010[2]:				
Revenue:				
Revenues third party[1]	$ 235,190	$	$ (9,213)	$ 225,977
Revenues affiliates	141			141
Total revenue and other income (loss), net	235,331		(9,213)	226,118
Costs and expenses:				
Operating costs and expenses	191,772			191,772
General and administrative[1]			7,578	7,578
Depreciation and amortization	18,566			18,566
Interest expense[1]			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

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	Gathering and Processing	Pipeline	Corporate and Other	Consolidated
Nine Months Ended September 30, 2011:				
Revenue:				
Revenues third party[1]	$ 982,739	$	$ 3,833	$ 986,572
Revenues affiliates	256			256
Total revenue and other income (loss), net	982,995		3,833	986,828
Costs and expenses:				
Operating costs and expenses	815,573	129		815,702
General and administrative[1]			26,821	26,821
Other costs		583		583
Depreciation and amortization	57,499			57,499
Interest expense[1]			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[2]:				
Revenue:				
Revenues third party[1]	$ 692,052	$	$ (10,026)	$ 682,026
Revenues affiliates	472			472
Total revenue and other income (loss), net	692,524		(10,026)	682,498
Costs and Expenses:				
Operating costs and expenses	558,708			558,708
General and administrative[1]			23,521	23,521
Depreciation and amortization	55,647			55,647
Interest expense[1]			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,

Capital Expenditures:	**2011**	**2010(2)**	**2011**	**2010(2)**
Gathering and Processing	$ 56,175	$ 11,340	$ 148,144	$ 32,078
Pipeline				
	$ 56,175	$ 11,340	$ 148,144	$ 32,078

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
Natural gas and liquids:				
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	$ 341,498	$ 220,478	$ 937,975	$ 641,978

(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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Balance Sheets September 30, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
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	$ 1,690,387	$ 2,535,238	$ 3,284,923	$ (5,630,235)	$ 1,880,313
Liabilities and Equity					
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	$ 1,690,387	$ 2,535,238	$ 3,284,923	$ (5,630,235)	$ 1,880,313

December 31, 2010	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
Assets					
Cash and cash equivalents	$	$ 164	$	$	$ 164
Accounts receivable affiliates	1,329,448			(1,329,448)	
Other current 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	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848
Liabilities and Equity					
Accounts payable affiliates	$	$ 1,173,729	$ 167,999	$ (1,329,448)	$ 12,280
Current portion of derivative liability		4,564			4,564
Other current liabilities	2,102	47,162	85,498		134,762
Total current liabilities	2,102	1,225,455	253,497	(1,329,448)	151,606

Long-term derivative liability		5,608			5,608
Long-term debt, less current portion	565,231		533		565,764
Other long-term liability		223			223
Equity	1,041,647	(1,440,864)	2,913,062	(1,472,198)	1,041,647
Total liabilities and equity	$ 1,608,980	$ (209,578)	$ 3,167,092	$ (2,801,646)	$ 1,764,848

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Statements of Operations Three Months Ended September 30, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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)	$ 49,756	$ 54,677	$ 38,113	$ (92,288)	$ 50,258
Three Months Ended September 30, 2010[1]					
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)	$ 283,090	$ 300,059	$ 26,688	$ (321,367)	$ 288,470
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)	$ 298,493	$ 340,009	$ 100,300	$ (438,151)	$ 300,651
Nine Months Ended September 30, 2010[1]					
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)	$ 283,665	$ 323,520	$ 80,781	$ (396,967)	$ 290,999

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Statements of Cash Flows Nine Months Ended September 30, 2011	Parent	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Consolidating Adjustments	Consolidated
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

Statements of Cash Flows Nine Months Ended September 30, 2010					
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

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
Pricing:						
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%
Operating data:						
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[1]:						
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):

	Three Months Ended September 30, 2011	2010	Variance	Percent Change
Revenues:				
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%
Total Revenues	$ 379,780	$ 226,118	$ 153,662	68.0%

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):

	Three Months Ended September 30, 2011	2010	Variance	Percent Change
Costs and Expenses:				
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)%
Total Costs and Expenses	$ 331,307	$ 241,003	$ 90,304	37.5%

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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 September 30,			
	2011	**2010**	**Variance**	**Percent Change**
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):

	Nine Months Ended September 30,			
	2011	2010	Change	Percent Change
Revenues:				
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%
Total Revenues	$ 986,828	$ 682,498	$ 304,330	44.6%

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 September 30, 2011	2010	Change	Percent Change
Costs and Expenses:				
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)%
Total Costs and Expenses	$ 925,130	$ 711,961	$ 213,169	29.9%

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 September 30, 2011	Nine Months Ended September 30, 2010	Change	Percent 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 September 30, 2011	Nine Months Ended September 30, 2010	Variance	Percent Change
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 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):

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

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 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.

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.

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.

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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 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. Dubay 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. Dubay 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

Exhibit No.	Description
2.1	Securities Purchase Agreement, dated July 27, 2010, by and among Atlas Pipeline Mid-Continent, LLC, Atlas Pipeline Partners, L.P., Enbridge Pipelines (Texas Gathering) L.P. and Enbridge Energy Partners, L.P.(12)
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. (13)
3.1	Certificate of Limited Partnership(1)
3.2(a)	Second Amended and Restated Agreement of Limited Partnership(2)
3.2(b)	Amendment No. 1 to Second Amended and Restated Agreement of Limited Partnership(3)
3.2(c)	Amendment No. 2 to Second Amended and Restated Agreement of Limited Partnership(4)
3.2(d)	Amendment No. 3 to Second Amended and Restated Agreement of Limited Partnership(5)
3.2(e)	Amendment No. 4 to Second Amended and Restated Agreement of Limited Partnership(6)
3.2(f)	Amendment No. 5 to Second Amended and Restated Agreement of Limited Partnership(8)
3.2(g)	Amendment No. 6 to Second Amended and Restated Agreement of Limited Partnership(9)
3.2(h)	Amendment No. 7 to Second Amended and Restated Agreement of Limited Partnership(14)
3.2(i)	Amendment No. 8 to Second Amended and Restated Agreement of Limited Partnership(15)
4.1	Common unit certificate(1)
4.2	8 3/4% Senior Notes Indenture dated June 27, 2008(7)
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(16)
10.1(a)	Amendment No. 1 to the Amended and Restated Credit Agreement dated as of April 19, 2011(22)
10.1(b)	Incremental Joinder Agreement to the Amended and Restated Credit Agreement dated as of July 8, 2011(23)
10.2	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Pipeline Operating Partnership, L.P.(14)
10.3	Long-Term Incentive Plan(21)
10.4	Amended and Restated 2010 Long-Term Incentive Plan(22)
10.5	Form of Grant of Phantom Units in Exchange for Bonus Units(17)
10.6	Form of 2010 Long-Term Incentive Plan Phantom Unit Grant Letter(18)
10.7	Form of Grant of Phantom Units to Non-Employee Managers(19)
10.8	Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan(21)
10.9	Form of Atlas Pipeline Mid-Continent, LLC 2009 Equity-Indexed Bonus Plan Grant Agreement(21)
10.10	Employment Agreement, dated as of January 15, 2009, between Atlas America, Inc. and Eugene N. Dubay(10)
10.11	Letter Agreement, dated as of August 31, 2009, between Atlas America, Inc. and Eric Kalamaras(11)
10.12	Phantom Unit Grant Agreement between Atlas Pipeline Mid-Continent, LLC and Eric Kalamaras, dated September 14, 2009(11)
10.13	Letter Agreement, by and between Atlas Pipeline Partners, L.P. and Atlas Pipeline Holdings, L.P., dated November 8, 2010(13)
10.14	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010(20)

10.15	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010[(20)]

10.16	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[24]
10.17	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[24]
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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Exhibit No.	Description
32.2	Section 1350 Certification
101.INS	XBRL Instance Document(25)
101.SCH	XBRL Schema Document(25)
101.CAL	XBRL Calculation Linkbase Document(25)
101.LAB	XBRL Label Linkbase Document(25)
101.PRE	XBRL Presentation Linkbase Document(25)
101.DEF	XBRL Definition Linkbase Document(25)

(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.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	ATLAS PIPELINE PARTNERS, L.P. By: Atlas Pipeline Partners GP, LLC, its General Partner
Date: 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