PRENTISS PROPERTIES TRUST/MD
Form 8-K/A
April 20, 2005

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 8-K/A

CURRENT REPORT

PURSUANT TO SECTION 13 OR 15(d) OF THE

SECURITIES EXCHANGE ACT OF 1934

Date of report (Date of earliest event reported):

April 19, 2005

Prentiss Properties Trust

(Exact Name of Registrant as Specified in Charter)

Maryland	**1-14516**	**75-2661588**
(State or Other Jurisdiction of Incorporation)	**(Commission File Number)**	**(IRS Employer Identification No.)**

3890 W. Northwest Hwy., Suite 400

Dallas, Texas 75220

(Address and Zip Code of Principal Executive Offices)

(214) 654-0886

(Registrant s telephone number, including area code)

Not Applicable

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

¨ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

¨ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

¨ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

¨ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

EXPLANATORY NOTE

On April 19, 2005, we filed a Current Report on Form 8-K with the Securities and Exchange Commission (the SEC), which furnished to the SEC (a) the Press Release of Prentiss Properties Trust (the Company) dated April 18, 2005, announcing the results of operations of the Company for the quarter ended March 31, 2005, as Exhibit 99.1, and (b) Supplemental Operating & Financial Data of the Company for the quarter ended March 31, 2005, as Exhibit 99.2. Pages 23 through 31, 35 and 36 of the Supplemental Operating & Financial Data of the Company for the quarter ended March 31, 2005, attached as Exhibit 99.2 to the original Current Report on Form 8-K, were inadvertently omitted from such Exhibit 99.2. This Amendment to Form 8-K is being filed to correct that omission and refurnish to the SEC, in its entirety, the Supplemental Operating & Financial Data of the Company for the quarter ended March 31, 2005, including the previously omitted pages, and the Press Release of the Company dated April 18, 2005, announcing the results of operations of the Company for the quarter ended March 31, 2005. Other than including the previously omitted pages 23 through 31, 35 and 36 from the Supplemental Operating & Financial Data of the Company for the quarter ended March 31, 2005, this Form 8-K/A is unchanged from our previously filed Form 8-K, filed on April 19, 2005.

Item 2.02. Disclosure of Results of Operations and Financial Condition.

On April 18, 2005, we issued a press release regarding our results of operations for the quarter ended March 31, 2005. A copy of this press release is attached hereto as Exhibit 99.1. In addition, we posted on our web site supplemental information regarding our operations for the quarter ended March 31, 2005, a copy of which is attached hereto as Exhibit 99.2.

At 10:00 am central daylight savings time on April 19, 2005, we will hold our earnings conference call for the quarter ended March 31, 2005.

The information disclosed under this Item 2.02, including Exhibits 99.1 and 99.2, shall not be deemed filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the Exchange Act), nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, as amended, or the Exchange Act.

Item 9.01 EXHIBITS

Exhibit Number	**Description**
99.1	Press Release of the Company dated April 18, 2005, announcing the results of operations of the Company for the quarter ended March 31, 2005.
99.2	Supplemental Operating & Financial Data of the Company for the quarter ended March 31, 2005.

SIGNATURES

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

	Prentiss Properties Trust	
Date: April 20, 2005	By:	/s/ Gregory S. Imhoff
		Gregory S. Imhoff
		Senior Vice President and Secretary

EXHIBIT INDEX

Exhibit Number	Description
99.1	Press Release of the Company dated April 18, 2005, announcing the results of operations of the Company for the quarter ended March 31, 2005.
99.2	Supplemental Operating & Financial Data of the Company for the quarter ended March 31, 2005.

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PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED BALANCE SHEETS

(in thousands)

(Unaudited)

	September 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 24,266	$ 54,708
Accounts receivable	29,743	19,319
Current portion of derivative asset	6,518	13,801
Subscriptions receivable	8,495	34,455
Prepaid expenses and other	7,107	7,677
Total current assets	76,129	129,960
Property, plant and equipment, net	1,016,110	520,883
Goodwill and intangible assets, net	33,149	33,285
Long-term derivative asset	5,144	16,128
Other assets, net	8,410	857
	$ 1,138,942	$ 701,113
LIABILITIES AND PARTNERS CAPITAL/EQUITY		
Current liabilities:		
Accounts payable	$ 42,831	$ 36,731
Liabilities associated with drilling contracts	5,550	71,719
Current portion of derivative liability	280	
Current portion of derivative payable to Drilling Partnerships	13,363	20,900
Accrued well drilling and completion costs	50,169	17,585
Accrued liabilities	33,039	35,952
Total current liabilities	145,232	182,887
Long-term debt	222,000	
Long-term derivative liability	4,051	
Long-term derivative payable to Drilling Partnerships	4,483	15,272
Asset retirement obligations and other	54,428	45,779
Commitments and contingencies		
Partners Capital/Equity:		
General partner s interest	7,646	
Preferred limited partners interests	96,110	
Common limited partners interests	596,348	
Equity		427,246

Accumulated other comprehensive income	8,644	29,929
Total partners capital/equity	708,748	457,175
	$ 1,138,942	$ 701,113

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenues:				
Gas and oil production	$ 24,699	$ 16,305	$ 61,323	$ 51,654
Well construction and completion	36,317	35,657	92,277	64,336
Gathering and processing	4,134	4,431	10,311	14,048
Administration and oversight	4,440	2,337	8,586	5,073
Well services	5,086	4,910	15,344	15,051
Other, net	67	(50)	(4,952)	(115)
Total revenues	74,743	63,590	182,889	150,047
Costs and expenses:				
Gas and oil production	7,295	3,990	16,247	11,953
Well construction and completion	31,581	30,449	79,882	54,754
Gathering and processing	4,558	4,880	13,185	16,377
Well services	2,232	2,043	7,076	6,077
General and administrative	16,147	4,757	48,427	12,275
Chevron transaction expense	7,670		7,670	
Depreciation, depletion and amortization	13,918	8,071	33,848	24,019
Total costs and expenses	83,401	54,190	206,335	125,455
Operating income (loss)	(8,658)	9,400	(23,446)	24,592
Interest expense	(1,423)		(2,529)	
Gain (loss) on asset sales and disposal	2		(7,019)	48
Net income (loss)	(10,079)	9,400	(32,994)	24,640
Preferred limited partner dividends	(1,221)		(1,221)	
Net income (loss) attributable to owner s interest, common limited partners and the general partner	$ (11,300)	$ 9,400	$ (34,215)	$ 24,640
Allocation of net income (loss):				
Portion applicable to owner s interest (period prior to the transfer of assets on March 5, 2012)	$	$ 9,400	$ 250	$ 24,640
Portion applicable to common limited partners and the general partner s interests (period subsequent to the transfer of assets on March 5, 2012)	(11,300)		(34,465)	
Net income (loss) attributable to owner s interest, common limited partners and the general partner	$ (11,300)	$ 9,400	$ (34,215)	$ 24,640

Allocation of net loss attributable to common limited partners and the general partner:				
Common limited partners interest	$ (11,074)	$	$ (33,776)	$
General partner s interest	(226)		(689)	
Net loss attributable to common limited partners and the general partner	$ (11,300)	$	$ (34,465)	$
Net loss attributable to common limited partners per unit:				
Basic	$ (0.32)	$	$ (1.06)	$
Diluted	$ (0.32)	$	$ (1.06)	$
Weighted average common limited partner units outstanding:				
Basic	35,068		31,865	
Diluted	35,068		31,865	

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income (loss)	$ (10,079)	$ 9,400	$ (32,994)	$ 24,640
Income attributable to owner s interest (period prior to the transfer of assets on March 5, 2012)		(9,400)	(250)	(24,640)
Preferred limited partner dividends	(1,221)		(1,221)	
Net loss attributable to common limited partners and the general partner	(11,300)		(34,465)	
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	(19,487)	10,884	(5,832)	17,733
Less: reclassification adjustment for realized gains in net income (loss)	(6,114)	(279)	(15,453)	(9,588)
Total other comprehensive income (loss)	(25,601)	10,605	(21,285)	8,145
Comprehensive income (loss) attributable to owner s interest, common limited partners and the general partner	$ (36,901)	$ 20,005	$ (55,500)	$ 32,785
Comprehensive income (loss) attributable to owner s interest (period prior to the transfer of assets on March 5, 2012)	$	$ 20,005	$ (4,722)	$ 32,785
Comprehensive income (loss) attributable to common limited partners and the general partner s interests (period subsequent to the transfer of assets on March 5, 2012)	$ (36,901)	$	$ (50,778)	$

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENT OF PARTNERS CAPITAL/EQUITY

(in thousands, except unit data)

(Unaudited)

	General Partners Interest		Preferred Limited Partners Interests		Common Limited Partners Interests			Accumulated Other Comprehensive	Total Partners Capital/
	Class A Units	Amount	Units	Amount	Units	Amount	Equity	Income	Equity
Balance at January 1, 2012		$		$		$	$ 427,246	$ 29,929	$ 457,175
Net income attributable to owner s interest prior to the transfer of assets on March 5, 2012							250		250
Net investment from owner s interest prior to the transfer of assets on March 5, 2012							5,625		5,625
Net assets contributed by owner to Atlas Resource Partners, L.P.	534,694	8,662			26,200,114	424,459	(433,121)		
Issuance of units	279,826		3,841,719	94,889	9,869,664	214,192			309,081
Unissued common units under incentive plans						7,833			7,833
Distributions paid to common limited partners and the general partner		(327)				(16,035)			(16,362)
Distribution equivalent rights paid on unissued units under incentive plan						(325)			(325)
Net income (loss) attributable to common and preferred limited partners and the general partner subsequent to the transfer of assets on March 5, 2012		(689)		1,221		(33,776)			(33,244)
Other comprehensive income (loss)								(21,285)	(21,285)
Balance at September 30, 2012	814,520	$ 7,646	3,841,719	$ 96,110	36,069,778	$ 596,348	$	$ 8,644	$ 708,748

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (32,994)	$ 24,640
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	33,848	24,019
Non-cash (gain) loss on derivative value, net	(17,013)	43,472
(Gain)/loss on asset sales and disposal	7,019	(48)
Non-cash compensation expense	7,856	
Amortization of deferred financing costs	1,028	
Changes in operating assets and liabilities:		
Accounts receivable and prepaid expenses and other	16,105	(6,533)
Accounts payable and accrued liabilities	(30,836)	(44,003)
Net cash provided by (used in) operating activities	(14,987)	41,547
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(73,379)	(36,270)
Net cash paid for acquisitions	(264,558)	
Other	69	
Net cash used in investing activities	(337,868)	(36,270)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	264,000	
Repayments under credit facilities	(42,000)	
Net investment from owners	5,625	54,709
Distributions paid to unit holders	(16,362)	
Net proceeds from issuance of common limited partner units	119,389	
Deferred financing costs and other	(8,239)	
Net cash provided by financing activities	322,413	54,709
Net change in cash and cash equivalents	(30,442)	59,986
Cash and cash equivalents, beginning of year	54,708	
Cash and cash equivalents, end of period	$ 24,266	$ 59,986

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED COMBINED FINANCIAL STATEMENTS

September 30, 2012

(Unaudited)

NOTE 1 BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the Partnership) is a publicly traded Delaware master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas and oil with operations in basins across the United States. The Partnership sponsors and manages tax-advantaged investment partnerships, in which it coinvests, to finance a portion of its natural gas and oil production activities. At September 30, 2012, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units and incentive distribution rights through which it manages and effectively controls the Partnership, and an approximate 51.5% limited partnership interest (20,960,000 limited partner units) in the Partnership.

The Partnership was formed in October 2011 to own and operate substantially all of ATLS exploration and production assets (the Atlas Energy E&P Operations), which were transferred to the Partnership on March 5, 2012. In February 2012, the board of ATLS general partner approved the distribution of approximately 5.24 million of the Partnership s common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 of the Partnership s limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of the Partnership s limited partner units represented approximately 20% of the common limited partner units outstanding.

The accompanying consolidated combined financial statements, which are unaudited except that the balance sheet at December 31, 2011 is derived from audited financial statements, are presented in accordance with the requirements of Form 10-Q and accounting principles generally accepted in the United States for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management s opinion, all adjustments necessary for a fair presentation of the Partnership s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated combined financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2011. Certain amounts in the prior year s combined financial statements have been reclassified to conform to the current year presentation. The results of operations for the three and nine months ended September 30, 2012 may not necessarily be indicative of the results of operations for the full year ending December 31, 2012.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Combination

The Partnership s consolidated combined balance sheet at September 30, 2012, the statement of operations for the three months ended September 30, 2012, and the portion of the consolidated combined statement of operations for the nine months ended September 30, 2012 subsequent to the transfer of assets on March 5, 2012 include the accounts of the Partnership and its wholly-owned subsidiaries. The Partnership s combined balance sheet at December 31, 2011, the portion of the consolidated combined statements of operations for the nine months ended September 30, 2012 prior to the transfer of assets on March 5, 2012 and the combined statement of operations for the three and nine months ended September 30, 2011 were derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if the Partnership had been operated as an unaffiliated entity. Because a direct ownership relationship did not exist among all of the various entities comprising Atlas E&P Operations prior to the date of transfer, ATLS net investment is shown as equity in the combined financial statements. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated combined balance sheets and related consolidated combined statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management s best estimates, in order to derive the financial statements of the Partnership for the periods presented. Actual balances and results could be different from those estimates. Transactions between the Partnership and other ATLS operations have been identified in the consolidated combined statements as transactions between affiliates, where applicable.

On February 17, 2011, ATLS acquired certain natural gas and oil properties, the partnership management business, and other assets (the Transferred Business) from Atlas Energy, Inc. (AEI), the former owner of ATLS general partner (see Note 3). Management of ATLS determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the

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asset acquisition would have been allocated to identifiable assets and liabilities of the Transferred Business based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity on the Partnership s combined balance sheet. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in the Partnership s consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, the Partnership reflected the impact of the acquisition of the Transferred Business on its consolidated combined financial statements in the following manner:

Recognized the assets acquired and liabilities assumed from the Transferred Business at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity;

Retrospectively adjusted its consolidated combined financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect its results on a consolidated combined basis with the results of the Transferred Business as of or at the beginning of the respective period; and

Adjusted the presentation of its consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners and the general partner. The Transferred Business historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by AEI to the underlying business segments, including the Transferred Business. The Partnership has reviewed AEI s general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business historical financial statements prior to the date of acquisition and believes the methodology is reasonable and reflects the approximate general and administrative costs of its underlying business segments.

In accordance with established practice in the oil and gas industry, the Partnership s consolidated combined financial statements include its pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the energy partnerships in which the Partnership has an interest (the Drilling Partnerships). Such interests typically range from 20% to 41%. The Partnership s financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, the Partnership calculates these items specific to its own economics as further explained under the heading Property, Plant and Equipment elsewhere within this note.

Use of Estimates

The preparation of the Partnership s consolidated combined financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership s consolidated combined financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership s consolidated combined financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired. Such estimates included estimated allocations made from the historical accounting records of AEI in order to derive the historical financial statements of the Partnership. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months financial results were recorded using estimated volumes and contract market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented for the three and nine months ended September 30, 2012 and 2011 represent actual results in all material respects (see *Revenue Recognition* accounting policy for further description).

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Receivables

Accounts receivable on the consolidated combined balance sheets consist solely of the trade accounts receivable associated with the Partnership s operations. In evaluating the realizability of its accounts receivable, the Partnership s management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by management s review of the Partnership s customers credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At September 30, 2012 and December 31, 2011, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated combined balance sheets.

Inventory

The Partnership had $4.0 million and $3.9 million of inventory at September 30, 2012 and December 31, 2011, respectively, which were included within prepaid expenses and other current assets on the Partnership s consolidated combined balance sheets. The Partnership values inventories at the lower of cost or market. The Partnership s inventories, which consist of materials, pipes, supplies and other inventories, were principally determined using the average cost method.

Property, Plant and Equipment

Property, plant and equipment are stated at cost or, upon acquisition of a business, at the fair value of the assets acquired. Maintenance and repairs which generally do not extend the useful life of an asset for two years or more through the replacement of critical components are expensed as incurred. Major renewals and improvements which generally extend the useful life of an asset for two years or more through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset s estimated useful life. 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 follows the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and natural gas liquids (NGLs) are converted to gas equivalent basis (Mcfe) at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

The Partnership s depletion expense is determined on a field-by-field basis using the units-of-production method. Depletion rates for leasehold acquisition costs are based on estimated proved reserves, and depletion rates for well and related equipment costs are based on proved developed reserves associated with each field. Depletion rates are determined based on reserve quantity estimates and the capitalized costs of undeveloped and developed producing properties. Capitalized costs of developed producing properties in each field are aggregated to include the Partnership s costs of property interests in proportionately consolidated investment partnerships, joint venture wells, wells drilled solely by the Partnership for its interests, properties purchased and working interests with other outside operators.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Partnership s consolidated combined statements of operations. Upon the sale of an individual well, the Partnership credits the proceeds to accumulated depreciation and depletion within its consolidated combined balance sheets. Upon the Partnership s sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Partnership s consolidated combined statements of operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

Impairment of Long-Lived Assets

The Partnership reviews its long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset s estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

The review of the Partnership s oil and gas properties is done on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the

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Partnership s plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Partnership estimates prices based upon current contracts in place, adjusted for basis differentials and market related information including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results. In particular, the Partnership s reserve estimates for its investment in the Drilling Partnerships are based on its own assumptions rather than its proportionate share of the limited partnerships reserves. These assumptions include the Partnership s actual capital contributions, an additional carried interest (generally 5% to 10%), a disproportionate share of salvage value upon plugging of the wells and lower operating and administrative costs.

The Partnership s lower operating and administrative costs result from the limited partners in the Drilling Partnerships paying to the Partnership their proportionate share of these expenses plus a profit margin. These assumptions could result in the Partnership s calculation of depletion and impairment being different than its proportionate share of the Drilling Partnerships calculations for these items. In addition, reserve estimates for wells with limited or no production history are less reliable than those based on actual production. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information which could cause the assumptions to be modified. The Partnership cannot predict what reserve revisions may be required in future periods.

The Partnership s method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Partnership sponsors and owns an interest in but does not control. The Partnership s reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Partnership may be unable to recover due to the Drilling Partnerships legal structure. The Partnership may have to pay additional consideration in the future as a well or Drilling Partnership becomes uneconomic under the terms of the Drilling Partnership s agreement in order to recover these excess reserves and to acquire any additional residual interests in the wells held by other partnership investors. The acquisition of any well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership s agreement and in general, must be at fair market value supported by an appraisal of an independent expert selected by the Partnership.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2012 and 2011.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2011, the Partnership recognized $7.0 million of asset impairment related to gas and oil properties within property, plant and equipment on its combined balance sheet for its shallow natural gas wells in the Niobrara Shale. This impairment related to the carrying amount of these gas and oil properties being in excess of the Partnership s estimate of their fair value at December 31, 2011. The estimate of the fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement. There were no impairments of proved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2012 and 2011.

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 combined borrowed funds by the Partnership was 3.1% and 3.5% for the three and nine months ended September 30, 2012, respectively, and 2.4% for the nine months ended September 30, 2011. The aggregate amounts of interest capitalized by the Partnership were $0.6 million and $1.0 million for the three and nine months ended September 30, 2012, respectively, and $0.1 million for the nine months ended September 30, 2011. There was no interest capitalized during the three months ended September 30, 2011.

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Intangible Assets

The Partnership recorded its intangible assets with finite lives in connection with partnership management and operating contracts acquired through prior consummated acquisitions. The Partnership amortizes contracts acquired on a declining balance method over their respective estimated useful lives.

The following table reflects the components of intangible assets being amortized at September 30, 2012 and December 31, 2011 (in thousands):

	September 30, 2012	December 31, 2011	Estimated Useful Lives In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(12,979)	(12,843)	
Net Carrying Amount	$ 1,365	$ 1,501	

Amortization expense on intangible assets was $45,000 and $0.2 million for the three months ended September 30, 2012 and 2011, respectively, and $0.1 million and $0.5 million for the nine months ended September 30, 2012 and 2011, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2012 $0.2 million; 2013 $0.2 million; 2014 $0.1 million; 2015 $0.1 million; and 2016 $0.1 million.

Goodwill

At September 30, 2012 and December 31, 2011, the Partnership had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. There were no changes in the carrying amount of goodwill for the three and nine months ended September 30, 2012 and 2011.

The Partnership tests goodwill for impairment at each year end by comparing its reporting unit estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership s management must apply judgment in determining the estimated fair value of these reporting units. The Partnership s management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership s assets. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership s market capitalization. The observed market prices of individual trades of an entity s equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership s, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership s management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership s industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership s industry to determine whether those valuations appear reasonable in management s judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the three and nine months ended September 30, 2012 and 2011, no impairment indicators arose and no goodwill impairments were recognized by the Partnership.

Derivative Instruments

The Partnership enters into certain financial contracts to manage its exposure to movement in commodity prices and interest rates (see Note 8). The derivative instruments recorded in the consolidated combined balance sheets were measured as either an asset or liability at fair value. Changes in a derivative instrument s fair value are recognized currently in the Partnership s consolidated combined statements of operations unless specific hedge accounting criteria are met.

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Asset Retirement Obligations

The Partnership recognizes an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities (see Note 6). The Partnership recognizes a liability for its future asset retirement obligations in the current period if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

Stock-Based Compensation

The Partnership recognizes all share-based payments to employees, including grants of employee stock options, in the consolidated combined financial statements based on their fair values (see Note 14).

Other Assets

The Partnership had $8.4 million and $0.9 million of other assets at September 30, 2012 and December 31, 2011, respectively, which were included on the Partnership s consolidated combined balance sheets. Of the $8.4 million of other assets at September 30, 2012, $6.9 million related to deferred financing costs (net of $1.6 million of accumulated amortization) associated with the Partnership s credit facility, which are recorded at cost and amortized over the term of the respective debt agreement. The Partnership recorded $0.5 million and $1.0 million of amortization of deferred financing costs during the three and nine months ended September 30, 2012, respectively.

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, which is determined after the deduction of the general partner s and the preferred unitholders interests, 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 Class A units. The General Partner s interest in net income (loss) is calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 13), 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.

Prior to the transfer of assets to the Partnership on March 5, 2012 (see Note 1), the Partnership had no common units or General Partner Class A units outstanding. In addition, the Partnership had no net income (loss) attributable to common limited partners and the general partner prior to March 5, 2012.

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. Phantom unit awards, which consist of common units issuable under the terms of its long-term incentive plan (see Note 14), contain non-forfeitable rights to distribution equivalents of the Partnership. The participation rights would 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 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) allocated to the common limited partners for purposes of calculating net loss attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Net income (loss)	$ (10,079)	$ 9,400	$ (32,994)	$ 24,640
Income applicable to owner s interest (period prior to transfer of assets on March 5, 2012)		(9,400)	(250)	(24,640)
Preferred limited partner dividends	(1,221)		(1,221)	
Net loss attributable to common limited partners and the general partner	(11,300)		(34,465)	
Less: General partner s interest	226		689	
Net loss attributable to common limited partners	(11,074)		(33,776)	
Less: Net income attributable to participating securities phantom units				
Net loss utilized in the calculation of net loss attributable to common limited partners per unit	$ (11,074)	$	$ (33,776)	$

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership s long-term incentive plan (see Note 14).

The following table sets forth the reconciliation of the Partnership s weighted average number of common limited partner units used to compute basic net income (loss) attributable to common limited partners per unit with those used to compute diluted net income (loss) attributable to common limited partners per unit (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Weighted average number of common limited partner units basic	35,068		31,865	
Add effect of dilutive incentive awards(1)				
Add effect of dilutive convertible preferred limited partner units(1)				
Weighted average number of common limited partner units diluted	35,068		31,865	

(1) For the three and nine months ended September 30, 2012, approximately 898,000 and 575,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the three and nine months ended September 30, 2012, potential common limited partner units issuable upon conversion of the Partnership s Class B preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

Revenue Recognition

Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership contracts with the Drilling Partnerships to drill partnership wells. The contracts require that the Drilling Partnerships must pay the Partnership the full contract price upon execution. The income from a drilling contract is recognized as the services are performed using the percentage of completion method. The contracts are typically completed between 60 and 270 days. On an uncompleted contract, the Partnership classifies the difference between the contract payments it has received and the revenue earned as a current liability titled Liabilities Associated with Drilling Contracts on the Partnership s consolidated combined balance sheets. The Partnership recognizes well services revenues at the time the services are performed. The Partnership is also entitled to receive management fees according to the respective partnership agreements and recognizes such fees as income when earned, which are included in administration and oversight revenues within its consolidated combined statements of operations.

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The Partnership generally sells natural gas, crude oil and NGLs at prevailing market prices. Generally, the Partnership s sales contracts are based on pricing provisions that are tied to a market index, with certain fixed adjustments based on proximity to gathering and transmission lines and the quality of its natural gas. Generally, the market index is fixed 2 business days prior to the commencement of the production month. Revenue and the related accounts receivable are recognized when produced quantities are delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Revenues from the production of natural gas, crude oil and NGLs, in which the Partnership has an interest with other producers, are recognized on the basis of its percentage ownership of the working interest and/or overriding royalty.

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs, and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership s records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see *Use of Estimates* accounting policy for further description). The Partnership had unbilled revenues at September 30, 2012 and December 31, 2011 of $22.4 million and $12.6 million, respectively, which were included in accounts receivable within the Partnership s consolidated combined balance sheets.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under accounting principles generally accepted in the United States, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as other comprehensive income (loss) and for the Partnership include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges.

Recently Adopted Accounting Standards

In October 2012, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2012-04, *Technical Corrections and Improvements* (Update 2012-04). The amendments in this update are presented in two sections Technical Corrections and Improvements (Section A) and Conforming Amendments Related to Fair Value Measurements (Section B). The amendments in Section A correct differences between source literature and the Accounting Standards Codification (ASC), provide clarification of guidance through updating wording, correcting references, or a combination of both, and move guidance from its current location in the ASC to a more appropriate location. The amendments in Section B are intended to conform terminology and clarify certain guidance in various topics of the ASC to fully reflect the fair value measurement and disclosure requirements of Topic 820. The amendments do not introduce any new fair value measurements and are not intended to result in a change in the application of the requirements in Topic 820 or fundamentally change other principles of U.S. GAAP. The amendments in Update 2012-04 that do not have transition guidance are effective upon issuance and those amendments that are subject to the transition guidance will be effective for fiscal periods beginning after December 15, 2012. The Partnership adopted the requirements of Update 2012-04 on September 30, 2012, and it did not have a material impact on its financial position, results of operations or related disclosures. The Partnership also believes the transition guidance will have no impact on its financial position, results of operations or related disclosures upon its effective date of January 1, 2013.

In August 2012, the FASB issued ASU 2012-03, *Technical Amendments and Corrections to SEC Sections: Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 114, Technical Amendments Pursuant to SEC Release No. 33-9250, and Corrections Related to FASB Accounting Standards Update 2010-22 (SEC Update) (Update 2012-03)*. Update 2012-03 codified amendments and corrections to the ASC for various Securities and Exchange Commission (SEC) paragraphs pursuant or related to 1) the issuance of Staff Accounting Bulletin (SAB) 114; 2) the SEC s Final Rule, *Technical Amendments to Commission Rules and Forms Related to the FASB s Accounting Standards Codification*, Release No. 3350-9250, 34-65052, and IC-29748 August 8, 2011; 3) ASU 2010-22, *Accounting for Various Topics Technical Corrections to SEC Paragraphs (SEC Update);* and 4) other various Status Sections. The Partnership adopted the requirements of Update 2012-03 on September 30, 2012, and it did not have a material impact on its financial position, results of operations or related disclosures.

In December 2011, the FASB issued ASU 2011-12, *Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05* (Update 2011-12). The amendments in this update effectively defer the implementation of the changes made in Update 2011-05, *Comprehensive Income (Topic 220): Presentation of*

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Comprehensive Income (Update 2011-05), related to the presentation of reclassification adjustments out of accumulated other comprehensive income. Under Update 2011-05 which was issued by the FASB in June 2011, entities are provided the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. Under each methodology, an entity is required to present each component of net income along with a total net income, each component of other comprehensive income and a total amount for comprehensive income. Update 2011-05 eliminates the option to present the components of other comprehensive income as part of the statement of changes in stockholders equity. As a result of Update 2011-12, entities are required to disclose reclassifications out of accumulated other comprehensive income consistent with the presentation requirements in effect prior to Update 2011-05. All other requirements in Update 2011-05 are not affected by Update 2011-12. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. Accordingly, entities are not required to comply with presentation requirements of Update 2011-05 related to the disclosure of reclassifications out of accumulated other comprehensive income. The Partnership included consolidated combined statements of comprehensive income (loss) within this Form 10-Q upon the adoption of these ASUs on January 1, 2012. The adoption had no material impact on the Partnership s financial condition or results of operations.

In December 2011, the FASB issued ASU 2011-11, *Balance Sheet (Topic 210): Disclosure about Offsetting Assets and Liabilities* (Update 2011-11). The amendments in this update require an entity to disclose both gross and net information about both financial and derivative instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an enforceable master netting arrangement or similar agreement, irrespective of whether they are offset on the statement of financial position. An entity shall disclose at the end of a reporting period certain quantitative information separately for assets and liabilities that are within the scope of Update 2011-11, as well as provide a description of the rights of setoff associated with an entity s recognized assets and recognized liabilities subject to an enforceable master netting arrangement or similar agreement. Entities are required to implement the amendments for interim and annual reporting periods beginning after January 1, 2013 and such amendments shall be applied retrospectively for any period presented that begins before the date of initial application. The Partnership has elected to early adopt these requirements and updated its disclosures to meet these requirements effective January 1, 2012 (see Note 8). The adoption had no material impact on the Partnership s financial position or results of operations.

In September 2011, the FASB issued ASU 2011-08, *Intangibles-Goodwill and Other (Topic 350): Testing Goodwill for Impairment* (Update 2011-08). The amendments in Update 2011-08 allow an entity to first assess qualitative factors in determining the necessity of performing the two-step quantitative goodwill impairment test. If, after assessing qualitative factors, an entity determines it is not likely that the fair value of a reporting unit is less than its carrying amount, performing the two-step impairment test is unnecessary. Under the amendments in Update 2011-08, an entity has the option to bypass the qualitative assessment and proceed directly to performing the first step of the two-step impairment test. The amendments are effective for interim and annual goodwill impairment tests performed for fiscal years beginning after December 15, 2011. The Partnership adopted the amendments of Update 2011-08 upon its effective date of January 1, 2012. The adoption had no material impact on the Partnership s financial position or results of operations.

In May 2011, the FASB issued ASU 2011-04, *Fair Value Measurements (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs* (Update 2011-04). The amendments in Update 2011-04 revise the wording used to describe many of the requirements for measuring fair value and for disclosing information about fair value measurements in U.S. GAAP. For many of the amendments, the guidance is not necessarily intended to result in a change in the application of the requirements in Topic 820; rather it is intended to clarify the intent about the application of existing fair value measurement requirements. Other amendments change a particular principle or requirement for measuring fair value or for disclosing information about fair value measurements. As a result, Update 2011-04 aims to provide common fair value measurement and disclosure requirements in U.S. GAAP and International Financial Reporting Standards. These requirements are effective for interim and annual reporting periods beginning after December 15, 2011. The Partnership updated its disclosures to meet these requirements upon the adoption of Update 2011-04 on January 1, 2012 (see Note 9). The adoption had no material impact on the Partnership s financial position or results of operations.

Recently Issued Accounting Standards

In July 2012, the FASB issued ASU 2012-02, *Intangibles Goodwill and Other (Topic 350): Testing Indefinite-Lived Intangible Assets for Impairment* (Update 2012-02). The amendments in Update 2012-02 allow an entity to first assess qualitative factors to determine whether the existence of events and circumstances indicates that it is more likely than not that the indefinite-lived intangible asset is impaired. The more likely than not threshold is defined as having a likelihood of more than 50 percent. If, after assessing qualitative factors, an entity determines it is not likely that the indefinite-lived intangible asset is impaired, then no further action is required. If impairment is deemed more likely than not, the entity is required to determine the fair value of the indefinite-lived intangible asset and perform the quantitative impairment test by comparing the fair value with the carrying amount of the asset. Additionally, under the amendments in Update 2012-02, an entity has the option to bypass the qualitative assessment for any indefinite-lived intangible asset in any period and proceed directly to performing the quantitative impairment test. An entity will be able to resume performing the qualitative assessment in any subsequent period. The amendments are effective for annual and interim impairment tests performed for fiscal years beginning after September 15, 2012, with early adoption being permitted. The Partnership will apply the requirements of Update 2012-02 upon its effective date of January 1, 2013, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

NOTE 3 ATLAS ENERGY, L.P. ACQUISITION FROM ATLAS ENERGY, INC.

On February 17, 2011, ATLS acquired the Transferred Business from AEI, including the following exploration and production assets that were transferred to the Partnership on March 5, 2012:

- AEI s investment management business which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which the Partnership funds a portion of its natural gas and oil well drilling;

- proved reserves located in the Appalachian Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan and the Chattanooga Shale of northeastern Tennessee; and

- certain producing natural gas and oil properties, upon which the Partnership is the developer and producer.

Concurrent with ATLS acquisition of the Transferred Business, AEI was sold to Chevron Corporation (NYSE: CVX) (Chevron). In connection with the transaction, ATLS received $118.7 million with respect to a contractual cash transaction adjustment from AEI related to certain exploration and production liabilities assumed by ATLS. Including the cash transaction adjustment, the net book value of the Transferred Business was approximately $522.9 million. Certain amounts included within the contractual cash transaction adjustment were subject to a reconciliation period with Chevron following the consummation of the transaction. The reconciliation period was assumed by the Partnership on March 5, 2012, as certain amounts included within the contractual cash transaction adjustment remained in dispute between the parties. During the three months ended September 30, 2012, the Partnership recognized a $7.7 million charge on its consolidated combined statement of operations regarding its reconciliation process with Chevron, which was settled in October 2012 (see Note 11).

Management of ATLS determined that the acquisition of the Transferred Business constituted a transaction between entities under common control. As such, ATLS recognized the assets acquired and liabilities assumed at historical carrying value at the date of acquisition, with the difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital on its consolidated combined balance sheet. ATLS recognized a non-cash decrease of $261.0 million in partners capital on its consolidated combined balance sheet based on the excess net book value above the value of the consideration paid to AEI. The following table presents the historical carrying value of the assets acquired and liabilities assumed by ATLS, including the effect of cash transaction adjustments, as of February 17, 2011 (in thousands):

Cash	$ 153,350
Accounts receivable	18,090
Accounts receivable affiliate	45,682
Prepaid expenses and other	6,955
Total current assets	224,077
Property, plant and equipment, net	516,625
Goodwill	31,784
Intangible assets, net	2,107
Other assets, net	20,416

Total long-term assets	570,932
Total assets acquired	$ 795,009
Accounts payable	$ 59,202
Net liabilities associated with drilling contracts	47,929
Accrued well completion costs	39,552
Current portion of derivative payable to Drilling Partnerships	25,659
Accrued liabilities	25,283
Total current liabilities	197,625
Long-term derivative payable to Drilling Partnerships	31,719
Asset retirement obligations	42,791
Total long-term liabilities	74,510
Total liabilities assumed	$ 272,135
Historical carrying value of net assets acquired	$ 522,874

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The Partnership reflected the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which the Transferred Business was acquired and retrospectively adjusted its prior year financial statements to furnish comparative information (see Note 2).

NOTE 4 ACQUISITIONS

Titan Acquisition

On July 25, 2012, the Partnership completed the acquisition of Titan Operating, L.L.C. (Titan) in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had a collective value of $193.2 million, based upon the closing price of the Partnership s publicly traded units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Note 12). Through the acquisition of Titan, the Partnership acquired interests in approximately 52 proved developed natural gas wells and approximately 250 Bcfe of proved reserves and 700 Bcfe of proved, probable and possible reserves and associated assets in the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas. The cash paid at closing was funded through borrowings under the Partnership s credit facility. The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act) (see Note 12). The Partnership accounted for the issuance of common and preferred limited partner units in exchange for the Titan assets acquired as a non-cash item in its consolidated combined statement of cash flows for the nine months ended September 30, 2012.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common and preferred limited partner units associated with the acquisition, the Partnership recorded $3.4 million of transaction fees within common and preferred limited partners interests for the three and nine months ended September 30, 2012 on the Partnership s consolidated combined balance sheets. All other costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Assets:	
Cash and cash equivalents	$ 372
Accounts receivable	5,253
Prepaid expenses and other	131
Total current assets	5,756
Natural gas and oil properties	210,704
Other assets, net	131
	$ 216,591
Liabilities:	
Accounts payable	$ 676
Revenue distribution payable	3,091
Accrued liabilities	1,816
Total current liabilities	5,583
Asset retirement obligation and other	2,418
	8,001

Net assets acquired	$ 208,590

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Carrizo Acquisition

On April 30, 2012, the Partnership completed the acquisition of certain oil and natural gas assets from Carrizo Oil and Gas, Inc. (NASDAQ: CRZO; Carrizo) for approximately $187.0 million in cash. The assets acquired include interests in approximately 200 producing natural gas wells from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, proved undeveloped acres also in the Barnett Shale and gathering pipelines and associated gathering facilities that service certain of the acquired wells. The purchase price was funded through borrowings under the Partnership s credit facility and $119.5 million of net proceeds from the sale of 6.0 million of its common units at a negotiated purchase price per unit of $20.00, of which $5.0 million was purchased by certain executives of the Partnership. The common units were issued in a private transaction exempt from registration under Section 4(2) of the Securities Act (see Note 12).

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $1.1 million of transaction fees within common limited partners interests for the nine months ended September 30, 2012 on the Partnership s consolidated combined balance sheet. All other costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Assets:	
Natural gas and oil properties	$ 190,946
Liabilities:	
Asset retirement obligation	3,903
Net assets acquired	$ 187,043

Due to the commingled nature of the Partnership s acquisitions in the Barnett Shale, it was impractical to provide separate financial information for each of the acquisitions subsequent to their respective dates of acquisition included within the Partnership s consolidated combined statements of operations for the three and nine months ended September 30, 2012. Subsequent to their respective dates of acquisition and combined with the effect of the Partnership s additional capital expenditures incurred, the Titan and Carrizo acquisitions had combined total revenues of $11.3 million and net income of $0.5 million for the three months ended September 30, 2012, and total combined revenues of $15.4 million and net loss of $0.6 million for the nine months ended September 30, 2012.

The following data presents pro forma revenues, net income (loss) and basic and diluted net income (loss) per unit for the Partnership as if the Titan and Carrizo acquisitions, including the borrowings under the credit facility and issuance of common and preferred units, had occurred on January 1, 2011. The Partnership prepared these pro forma unaudited financial results for comparative purposes only; they may not be indicative of the results that would have occurred if the acquisitions had occurred on January 1, 2011 or the results that will be attained in future periods (in thousands, except per share data; unaudited):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
Total revenues and other	$ 74,743	$ 83,957	$ 196,899	$ 212,567
Net income (loss)	(10,079)	13,869	(44,591)	39,229
Net income (loss) attributable to common limited partners and the general partner	(11,300)		(46,039)	
Net income (loss) attributable to common limited partners per unit:				
Basic	$ (0.32)	$	$ (1.25)	$

Diluted	$ (0.32)	$	$ (1.25)	$

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Equal Acquisition

In April 2012, the Partnership acquired a 50% interest in approximately 14,500 net undeveloped acres in the oil and NGL area of the Mississippi Lime play in northwestern Oklahoma for $18.0 million from subsidiaries of Equal Energy, Ltd. (Equal) (NYSE: EQU; TSX: EQU). The transaction was funded through borrowings under the Partnership s revolving credit facility. Concurrent with the purchase of acreage, the Partnership and Equal entered into a participation and development agreement for future drilling in the Mississippi Lime play. The Partnership served as the drilling and completion operator, while Equal undertook production operations, including water disposal. In September 2012, the Partnership acquired Equal s remaining 50% interest in the undeveloped acres, as well as approximately 8 Mmcfed of net production in the Mississippi Lime region and salt water disposal infrastructure for $41.3 million, including $1.3 million related to certain post-closing adjustments. The additional acquisition was subject to certain post-closing adjustments and funded with available borrowings under the Partnership s revolving credit facility. As a result of the Partnership s acquisition of Equal s remaining interest in the undeveloped acres, the existing joint venture agreement between the Partnership and Equal in the Mississippi Lime position was terminated and all infrastructure associated with the assets, principally the salt water disposal system, is operated by the Partnership.

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2012	December 31, 2011	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 159,999	$ 61,587	
Pre-development costs	1,796	2,540	
Wells and related equipment	1,060,481	828,780	
Total proved properties	1,222,276	892,907	
Unproved properties	231,040	43,253	
Support equipment	11,800	9,413	
Total natural gas and oil properties	1,465,116	945,573	
Pipelines, processing and compression facilities	32,178	32,149	2 40
Rights of way	84	84	20 40
Land, buildings and improvements	6,790	4,822	3 40
Other	8,983	1,180	3 10
	1,513,151	983,808	
Less accumulated depreciation, depletion and amortization	(497,041)	(462,925)	
	$ 1,016,110	$ 520,883	

In March 2012, the Partnership recognized a $7.0 million loss on asset disposal, pertaining to its decision to terminate a farm out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm out agreement contained certain well drilling targets for the Partnership to maintain ownership of the South Knox processing plant, which the Partnership s management decided in 2012 to not achieve due to the current natural gas price environment. As a result, the Partnership s management forfeited its interest in the processing plant and related properties and recorded a loss related to the net book values of those assets during the nine months ended September 30, 2012.

During the year ended December 31, 2011, the Partnership recognized $7.0 million of asset impairment related to its gas and oil properties within property, plant and equipment, net on its combined balance sheet for its shallow natural gas wells in the Niobrara Shale. This impairment related to the carrying amount of gas and oil properties being in excess of the Partnership s estimate of their fair value at December 31, 2011. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

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NOTE 6 ASSET RETIREMENT OBLIGATIONS

The Partnership recognized an estimated liability for the plugging and abandonment of its gas and oil wells and related facilities. The Partnership also recognized a liability for its future asset retirement obligations if a reasonable estimate of the fair value of that liability can be made. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The Partnership also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability was based on the Partnership s historical experience in plugging and abandoning wells, estimated remaining lives of those wells based on reserve estimates, external estimates as to the cost to plug and abandon the wells in the future and federal and state regulatory requirements. The liability was discounted using an assumed credit-adjusted risk-free interest rate. Revisions to the liability could occur due to changes in estimates of plugging and abandonment costs or remaining lives of the wells, or if federal or state regulators enact new plugging and abandonment requirements. The Partnership has no assets legally restricted for purposes of settling asset retirement obligations. Except for its gas and oil properties, the Partnership determined that there were no other material retirement obligations associated with tangible long-lived assets.

A reconciliation of the Partnership s liability for well plugging and abandonment costs for the periods indicated is as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Asset retirement obligations, beginning of period	$ 51,046	$ 43,932	$ 45,779	$ 42,673
Liabilities incurred	2,424	276	6,516	369
Liabilities settled	(198)	(18)	(448)	(150)
Accretion expense	768	650	2,193	1,948
Asset retirement obligations, end of period	$ 54,040	$ 44,840	$ 54,040	$ 44,840

The above accretion expense was included in depreciation, depletion and amortization in the Partnership s consolidated combined statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations and other in the Partnership s consolidated combined balance sheets. During the three and nine months ended September 30, 2012, the Partnership incurred $2.0 million and $5.9 million, respectively, of future plugging and abandonment costs related to the acquisitions it consummated during the period (see Note 4).

NOTE 7 DEBT

Credit Facility

At September 30, 2012, the Partnership had a senior secured credit facility with a syndicate of banks with a borrowing base of $310.0 million with $222.0 million outstanding. Concurrent with the closing of the Titan acquisition on July 25, 2012, the Partnership expanded the borrowing base on its revolving credit line from $250.0 million to $310.0 million. The credit facility matures in March 2016 and the borrowing base will be redetermined semi-annually in May and November. Up to $20.0 million of the credit facility may be in the form of standby letters of credit which would reduce the Partnership s borrowing capacity, of which $0.6 million was outstanding at September 30, 2012, and was not reflected as borrowings on the Partnership s consolidated combined balance sheet. The Partnership s obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets. Additionally, obligations under the facility are guaranteed by substantially all of the Partnership s subsidiaries. Borrowings under the credit facility bear interest, at the Partnership s election, at either LIBOR plus an applicable margin between 2.00% and 3.00% or the base rate (which is the higher of the bank s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.00%. The Partnership is also required to pay a fee of 0.5% per annum on the unused portion of the borrowing base, which is included within interest expense on its consolidated combined statements of operations. At September 30, 2012, the weighted average interest rate was 2.7%.

The credit agreement contains customary covenants that limit the Partnership s ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of September 30, 2012. The credit agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the credit agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the credit agreement) not greater than 3.75 to 1.0 as of the last day of any fiscal quarter, a ratio of current assets (as defined in the credit agreement) to current liabilities (as defined in the credit agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter, and a ratio of four quarters (actual or annualized, as applicable) of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.5 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership s credit facility, its ratio of current assets to current liabilities was 1.1 to 1.0, its ratio of Total Funded Debt to EBITDA was 2.2 to 1.0 and its ratio of EBITDA to Consolidated Interest Expense was 35.1 to 1.0 at September 30, 2012.

NOTE 8 DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps, collars and options, in connection with their commodity and interest rate price risk management activities. Management enters into financial instruments to hedge forecasted commodity 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 commodities are sold. Under commodity-based swap agreements, the Partnership receives or pays a fixed price and receives or remits a floating price based on certain indices for the relevant contract period. Commodity-based put option instruments are contractual agreements that require the payment of a premium and grant the purchaser of the put option the right, but not the obligation, to receive the difference between a fixed, or strike, price and a floating price based on certain indices for the relevant contract period, if the floating price is lower than the fixed price. The put option instrument sets a floor price for commodity sales being hedged. Costless collars are a combination of a purchased put option and a sold call option, in which the premiums net to zero. The costless collar eliminates the initial cost of the purchased put, but places a ceiling price for commodity sales being hedged.

Management formally documents all relationships between the Partnership s hedging instruments and the items being hedged, including its risk management objective and strategy for undertaking the hedging transactions. This includes matching the commodity derivative contracts to the forecasted transactions. Management assesses, both at the inception of the derivative and on an ongoing basis, whether the derivative is effective in offsetting changes in the forecasted cash flow of the hedged item. If it is determined that a derivative is not effective as a hedge or that it has ceased to be an effective hedge due to the loss of adequate correlation between the hedging instrument and the underlying item being hedged, the Partnership will discontinue hedge accounting for the derivative and subsequent changes in the derivative fair value, which is determined by management of the Partnership through the utilization of market data, will be recognized immediately within other, net in the Partnership s consolidated combined statements of operations. For derivatives qualifying as hedges, the Partnership recognizes the effective portion of changes in fair value of derivative instruments as accumulated other comprehensive income and reclassifies the portion relating to commodity derivatives to gas and oil production revenues within the Partnership s consolidated combined statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, management recognized changes in fair value within gain on mark-to-market derivatives in the Partnership s consolidated combined statements of operations as they occur.

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership s consolidated combined balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership s consolidated combined balance sheets as the initial value of the options. The Partnership reflected net derivative assets on its consolidated combined balance sheets of $7.3 million and $29.9 million at September 30, 2012 and December 31, 2011, respectively. Of the $8.6 million of net gain in accumulated other comprehensive income within partners capital/equity on the Partnership s consolidated combined balance sheet related to derivatives at September 30, 2012, if the fair values of the instruments remain at current market values, the Partnership will reclassify $5.2 million of gains to gas and oil production revenue on its consolidated combined statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $3.4 million of gas and oil production revenues will be reclassified to the Partnership s consolidated combined statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future price changes.

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

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Combined Balance Sheets	Net Amount of Assets Presented in the Consolidated Combined Balance Sheets
As of September 30, 2012			
Current portion of derivative assets	$ 11,078	$ (4,560)	$ 6,518
Long-term portion of derivative assets	12,256	(7,112)	5,144
Current portion of derivative liabilities	8	(8)	
Long-term portion of derivative liabilities	2,764	(2,764)	
Total derivative assets	$ 26,106	$ (14,444)	$ 11,662
As of December 31, 2011			
Current portion of derivative assets	$ 14,146	$ (345)	$ 13,801
Long-term portion of derivative assets	21,485	(5,357)	16,128
Total derivative assets	$ 35,631	$ (5,702)	$ 29,929

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Combined Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Combined Balance Sheets
As of September 30, 2012			
Current portion of derivative assets	$ (4,560)	$ 4,560	$
Long-term portion of derivative assets	(7,112)	7,112	
Current portion of derivative liabilities	(288)	8	(280)
Long-term portion of derivative liabilities	(6,815)	2,764	(4,051)
Total derivative liabilities	$ (18,775)	$ 14,444	$ (4,331)
As of December 31, 2011			
Current portion of derivative liabilities	$ (345)	$ 345	$

Long-term portion of derivative liabilities	(5,357)	5,357	
Total derivative liabilities	$ (5,702)	$ 5,702	$

The following table summarizes the gain or loss recognized in the Partnership s consolidated combined statements of operations for effective derivative instruments for the periods indicated (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	**2011**	**2012**	**2011**
Gain (loss) recognized in accumulated OCI	$ (19,487)	$ 10,884	$ (5,832)	$ 17,733
Gain reclassified from accumulated OCI into income	$ (6,114)	$ (279)	$ (15,453)	$ (9,588)

The Partnership enters into commodity future option and collar contracts to achieve more predictable cash flows by hedging its exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Exchange (NYMEX) futures and options contracts and non-regulated over-the-counter futures contracts with qualified counterparties. NYMEX contracts are generally settled with offsetting positions, but may be settled by the physical delivery of the commodity. Crude oil contracts are based on a West Texas Intermediate (WTI) index. These contracts have qualified and been designated as cash flow hedges and recorded at their fair values.

In March 2012, the Partnership entered into contracts which provided the option to enter into swap contracts (swaptions) up through May 31, 2012 for production volumes related to wells acquired from Carrizo (see Note 4). In connection with the swaption contracts, the Partnership paid premiums of $4.6 million, which represented the fair value of contracts on the date of the transaction and was initially recorded as a derivative asset on the Partnership s consolidated combined balance sheet and was fully amortized as of June 30, 2012. For the nine months ended September 30, 2012, the Partnership recorded approximately $4.6 million of amortization expense in other, net on the Partnership s consolidated combined statements of operations related to the swaption contracts.

In June 2012, the Partnership received approximately $3.9 million in net proceeds from the early termination of natural gas and oil derivative positions for production periods from 2015 through 2016. In conjunction with the early termination of these derivatives, the Partnership entered into new derivative positions at prevailing prices at the time of the transaction. The net proceeds from the early termination of these derivatives were used to reduce indebtedness under the Partnership s credit facility (see Note 7). The gain recognized upon the early termination of these derivative positions will continue to be reported in accumulated other comprehensive income and will be reclassified into the Partnership s consolidated statements of operations in the same periods in which the hedged production revenues would have been recognized in earnings.

The Partnership recognized gains of $6.1 million and $0.3 million for the three months ended September 30, 2012 and 2011, respectively, and $15.5 million and $9.6 million for the nine months ended September 30, 2012 and 2011, respectively, on settled contracts covering commodity production. These gains were included within gas and oil production revenue in the Partnership s consolidated combined statements of operations. As the underlying prices and terms in the Partnership s derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three and nine months ended September 30, 2012 and 2011 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At September 30, 2012, the Partnership had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes (mmbtu)(1)		Average Fixed Price (per mmbtu)(1)		Fair Value Asset/(Liability) (in thousands)(2)
2012	5,591,000	$	3.378	$	328
2013	21,529,700	$	3.853		114
2014	16,233,000	$	4.215		562
2015	11,994,500	$	4.259		(1,346)
2016	9,866,300	$	4.334		(2,056)
2017	3,600,000	$	4.579		(549)
				$	(2,947)

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (mmbtu)(1)		Average Floor and Cap (per mmbtu)(1)		Fair Value Asset/(Liability) (in thousands)(2)
2012	Puts purchased	1,080,000	$	4.074	$	880
2012	Calls sold	1,080,000	$	5.279		(2)
2013	Puts purchased	5,520,000	$	4.395		4,297
2013	Calls sold	5,520,000	$	5.443		(446)
2014	Puts purchased	3,840,000	$	4.221		2,230
2014	Calls sold	3,840,000	$	5.120		(1,065)
2015	Puts purchased	3,480,000	$	4.234		2,049
2015	Calls sold	3,480,000	$	5.129		(1,469)
					$	6,474

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Natural Gas Put Options

Production Period Ending December 31,	Option Type	Volumes (mmbtu)[1]	Average Fixed Price (per mmbtu)[1]	Fair Value Asset (in thousands)[2]
2012	Puts purchased	1,470,000	$ 2.802	$ 16
2013	Puts purchased	3,180,000	$ 3.450	633
2014	Puts purchased	1,800,000	$ 3.800	621
2015	Puts purchased	1,440,000	$ 4.000	634
2016	Puts purchased	1,440,000	$ 4.150	776
				$ 2,680

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Asset (in thousands)[3]
2012	6,750	$ 103.804	$ 96
2013	18,600	$ 100.669	129
2014	36,000	$ 97.693	221
2015	45,000	$ 89.504	23
			$ 469

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]	Fair Value Asset/ (Liability) (in thousands)[3]
2012	Puts purchased	15,000	$ 90.000	$ 50
2012	Calls sold	15,000	$ 117.912	(11)
2013	Puts purchased	60,000	$ 90.000	495
2013	Calls sold	60,000	$ 116.396	(167)
2014	Puts purchased	41,160	$ 84.169	388
2014	Calls sold	41,160	$ 113.308	(221)
2015	Puts purchased	29,250	$ 83.846	315
2015	Calls sold	29,250	$ 110.654	(194)
				$ 655
Total net asset				$ 7,331

(1) Mmbtu represents million British Thermal Units; Bbl represents barrels.

(2) Fair value based on forward NYMEX natural gas prices, as applicable.

(3) Fair value based on forward WTI crude oil prices, as applicable.

Prior to its merger with Chevron on February 17, 2011, AEI monetized its derivative instruments, including those related to the future natural gas and oil production of the Transferred Business (see Note 3). AEI also monetized derivative instruments which were specifically related to the future natural gas and oil production of the limited partners of the Drilling Partnerships. At September 30, 2012, remaining hedge monetization cash proceeds of $15.3 million related to the amounts hedged on behalf of the Drilling Partnerships limited partners were included within cash and cash equivalents on the Partnership s consolidated combined balance sheet, and the Partnership will allocate the monetization net proceeds to the Drilling Partnerships limited partners based on their natural gas and oil production generated over the period of the original derivative contracts. The Partnership reflected the remaining hedge monetization proceeds within current and long-term portion of derivative payable to Drilling Partnerships on its consolidated combined balance sheets as of September 30, 2012 and December 31, 2011.

In June 2012, the Partnership entered into natural gas put option contracts which related to future natural gas production of the Drilling Partnerships. Therefore, a portion of any unrealized derivative gain or loss is allocable to the limited partners of the Drilling Partnerships based on their share of estimated gas production related to the derivatives not yet settled. At September 30, 2012, net unrealized derivative assets of $2.5 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

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The derivatives payable to the Drilling Partnerships related to both the hedge monetization proceeds and future natural gas production of the Drilling Partnerships at September 30, 2012 and December 31, 2011 were included in the Partnership s consolidated combined balance sheets as follows (in thousands):

	September 30, 2012	December 31, 2011
Current portion of derivative payable to Drilling Partnerships:		
Hedge monetization proceeds	$ (13,032)	$ (20,900)
Hedge contracts covering future natural gas production	(331)	
Long-term portion of derivative payable to Drilling Partnerships:		
Hedge monetization proceeds	(2,325)	(15,272)
Hedge contracts covering future natural gas production	(2,158)	
	$ (17,846)	$ (36,172)

At September 30, 2012, the Partnership had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships will have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under its senior secured credit facility (see Note 7), the Partnership is required to utilize this secured hedge facility for future commodity risk management activity for its equity production volumes within the participating Drilling Partnerships. Each participating Drilling Partnership s obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets and by a guarantee of the general partner of the Drilling Partnerships. The Partnership, as general partner of the Drilling Partnerships, will administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership s ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

NOTE 9 FAIR VALUE OF FINANCIAL INSTRUMENTS

Management has established a hierarchy to measure the Partnership s financial instruments at fair value which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. 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. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 Unobservable inputs that reflect the entity s own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The Partnership uses a market approach fair value methodology to value the assets and liabilities for its outstanding derivative contracts (see Note 8). The Partnership manages and reports the derivative assets and liabilities on the basis of its net exposure to market risks and credit risks by counterparty. The Partnership s commodity derivative contracts are valued based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 assets and liabilities within the same class of nature and risk. These derivative instruments are calculated by utilizing the NYMEX quoted prices for futures and options contracts traded on NYMEX that coincide with the underlying commodity, expiration period, strike price (if applicable) and pricing formula utilized in the derivative instrument.

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Information for assets and liabilities measured at fair value at September 30, 2012 and December 31, 2011 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
As of September 30, 2012				
Derivative assets, gross				
Commodity swaps	$	$ 12,722	$	$ 12,722
Commodity puts		2,679		2,679
Commodity options		10,705		10,705
Total derivative assets, gross		26,106		26,106
Derivative liabilities, gross				
Commodity swaps		(15,201)		(15,201)
Commodity puts				
Commodity options		(3,574)		(3,574)
Total derivative liabilities, gross		(18,775)		(18,775)
Total derivatives, fair value, net	$	$ 7,331	$	$ 7,331
As of December 31, 2011				
Derivative assets, gross				
Commodity swaps	$	$ 20,908	$	$ 20,908
Commodity puts				
Commodity options		14,723		14,723
Total derivative assets, gross		35,631		35,631
Derivative liabilities, gross				
Commodity swaps				
Commodity puts				
Commodity options		(5,702)		(5,702)
Total derivative liabilities, gross		(5,702)		(5,702)
Total derivatives, fair value, net	$	$ 29,929	$	$ 29,929

Other Financial Instruments

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

The Partnership s other current assets and liabilities on its consolidated combined balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair values of outstanding borrowings under the revolving credit facility, which bear interest at a variable interest rate, approximate their estimated fair values and thus are categorized as Level 1.

Assets and Liabilities Measured at Fair Value on a Non-Recurring Basis

Management estimates the fair value of its asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors at the date of establishment of an asset retirement obligation such as: amounts and timing of settlements, the credit-adjusted risk-free rate of the Partnership and estimated inflation rates. Information for assets and liabilities that were measured at fair value on a nonrecurring basis for the three and nine months ended September 30, 2012 and 2011 were as follows (in thousands):

	Three Months Ended September 30,			
	2012		**2011**	
	Level 3	**Total**	**Level 3**	**Total**
Asset retirement obligations	$ 2,424	$ 2,424	$ 276	$ 276
Total	$ 2,424	$ 2,424	$ 276	$ 276

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	Nine Months Ended September 30,			
	2012		2011	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$ 6,516	$ 6,516	$ 369	$ 369
Total	$ 6,516	$ 6,516	$ 369	$ 369

Management estimates the fair value of the Partnership s long-lived assets in connection with reviewing these assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions and judgments regarding such events or circumstances. For the year ended December 31, 2011, the Partnership recognized a $7.0 million impairment of long-lived assets which was defined as a Level 3 fair value measurement (see Note 2 *Impairment of Long-Lived Assets*). No impairments were recognized for the three and nine months ended September 30, 2012 and 2011 (see Note 5).

During the nine months ended September 30, 2012, the Partnership completed the acquisitions of certain oil and gas assets from Carrizo and certain proved reserves and associated assets from Titan (see Note 4). The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of natural gas and oil properties were measured using a discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, future operating and development costs of the assets, as well as the respective natural gas, oil and natural gas liquids forward price curves. The fair values of the asset retirement obligations were measured under the Partnership s existing methodology for recognizing an estimated liability for the plugging and abandonment of its gas and oil wells (see Note 6). These inputs require significant judgments and estimates by the Partnership s management at the time of the valuation and are subject to change.

NOTE 10 CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

The Partnership conducts certain activities through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership serves as general partner and operator of the Drilling Partnerships and assumes customary rights and obligations for the Drilling Partnerships. As the general partner, the Partnership is liable for the Drilling Partnerships liabilities and can be liable to limited partners if it breaches its responsibilities with respect to the operations of the Drilling Partnerships. The Partnership is entitled to receive management fees, reimbursement for administrative costs incurred, and to share in the Drilling Partnership s revenue and costs and expenses according to the respective partnership agreements.

NOTE 11 COMMITMENTS AND CONTINGENCIES

General Commitments

The Partnership is the managing general partner of the Drilling Partnerships, and has agreed to indemnify each investor partner from any liability that exceeds such partner s share of Drilling Partnership assets. Subject to certain conditions, investor partners in certain Drilling Partnerships have the right to present their interests for purchase by the Partnership, as managing general partner. The Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year. Based on its historical experience, the management of the Partnership believes that any liability incurred would not be material. Also, the Partnership has agreed to subordinate a portion of its share of net partnership revenues from the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% per year determined on a cumulative basis, over a specific period, typically the first five to seven years, in accordance with the terms of the partnership agreements. For the three months ended September 30, 2012 and 2011, $1.8 million and $0.9 million, respectively, of the Partnership s revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships. For the nine months ended September 30, 2012 and 2011, $3.6 million of the Partnership s revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships.

Immediately following the acquisition of the Transferred Business, ATLS received from Chevron $118.7 million related to a contractual cash transaction adjustment related to certain liabilities of the Transferred Business at February 17, 2011. Following the closing of the acquisition of the Transferred Business, ATLS entered into a reconciliation process with Chevron to determine the final cash adjustment amount pursuant to the transaction agreement. The reconciliation process was assumed by the Partnership on March 5, 2012, as certain amounts included within the contractual cash transaction adjustment remained in dispute between the parties. During the three months ended September 30, 2012, the Partnership recognized a $7.7 million charge on its consolidated combined statement of operations regarding its reconciliation process with Chevron, which was settled in October 2012. At September 30, 2012, the Partnership had a $13.5 million liability included within accrued liabilities on its consolidated combined balance sheet related to the settlement of this matter.

The Partnership is party to employment agreements with certain executives that provide compensation and certain other benefits. The agreements also provide for severance payments under certain circumstances.

As of September 30, 2012, the Partnership is committed to expend approximately $20.4 million, principally on drilling and completion expenditures.

Legal Proceedings

A subsidiary of the Partnership entered into two agreements with the United States Environmental Protection Agency (the EPA), effective on September 25, 2012, to settle alleged violations in connection with a fire that occurred at a natural gas well and associated well pad site in Washington County, Pennsylvania in 2010. The EPA alleged non-compliance with the Clean Air Act, including with respect to the storage and handling of the natural gas condensate as well as non-compliance with the Emergency Planning and Community Right-to-Know Act of 1986. The subsidiary agreed to a civil penalty of $84,506 under a consent agreement and agreed to upgrade its facility pursuant to an administrative settlement agreement.

On August 3, 2011, CNX Gas Company LLC filed a lawsuit in the United States District Court for the Eastern District of Tennessee at Knoxville styled *CNX Gas Company LLC vs. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC, and Scott Boruff*, No. 3:11-cv-00362. On April 16, 2012 Atlas Energy Tennessee, LLC, an indirect wholly-owned subsidiary of the Partnership, was brought in to the lawsuit by way of Amended Complaint. On April 23, 2012, the Court dismissed Chevron Appalachia, LLC as a party on the grounds of lack of subject matter jurisdiction over that entity.

The lawsuit alleges that CNX entered into a Letter of Intent with Miller Energy for the purchase by CNX of certain leasehold interests containing oil and natural gas rights, representing around 30,000 acres in East Tennessee. The lawsuit also alleges that Miller Energy breached the Letter of Intent by refusing to close by the date provided and by allegedly entertaining offers from third parties for the same leasehold interests. Allegations of inducement of breach of contract and related claims are made by CNX against the remaining defendants, on the theory that these parties knew of the terms of the Letter of Intent and induced Miller Energy to breach the Letter of Intent. CNX is seeking $15.5 million in damages. The Partnership asserts that it acted in good faith and believes that the outcome of the litigation will be resolved in its favor.

The Partnership is also a party to various routine legal proceedings arising out of the ordinary course of its business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on the Partnership s financial condition or results of operations.

NOTE 12 ISSUANCES OF UNITS

Titan Acquisition

On July 25, 2012, the Partnership completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million Partnership common units and 3.8 million newly-created convertible Class B preferred units (which have a collective value of $193.2 million, based upon the closing price of the Partnership s publicly traded common units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Note 4). The preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike price of $26.03 plus all unpaid preferred distributions per unit, and will be mandatorily converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

The Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC by January 25, 2013 to register the resale of the common units issued on the acquisition closing date and those issuable upon conversion of the preferred units. The Partnership agreed to use its commercially reasonable efforts to have the registration statement declared effective by March 31, 2013, and to cause the registration statement to be continuously effective until the earlier of (i) the date as of which all such common units registered thereunder are sold by the holders and (ii) one year after the date of effectiveness. On September 19, 2012, the Partnership filed a registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement and the registration statement was declared effective by the SEC on October 2, 2012.

Carrizo Acquisition

On April 30, 2012, the Partnership completed the acquisition of certain oil and gas assets from Carrizo (see Note 4). To partially fund the acquisition, the Partnership sold 6.0 million of its common units in a private placement at a negotiated purchase price per unit of $20.00, for gross proceeds of $120.6 million, of which $5.0 million was purchased by certain executives of the Partnership. The common units issued by the Partnership are subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that the Partnership would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, the Partnership filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of one of the requirements of the registration rights agreement noted previously. On August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of these limited partner units represented approximately 20.0% of the common limited partner units outstanding (see Note 1).

NOTE 13 CASH DISTRIBUTIONS

The Partnership has a cash distribution policy under which it distributes, within 45 days following the end of each calendar quarter, all of its available cash (as defined in the partnership agreement) for that quarter to its common unitholders and general partner. If the Partnership s common unit distributions in any quarter exceed specified target levels, ATLS will receive between 13% and 48% of such distributions in excess of the specified target levels.

Date Cash Distribution Paid	For Quarter Ended	Cash Distribution per Common Limited Partner Unit	Total Cash Distribution to Common Limited Partners	Total Cash Distribution to the General Partner s Class A Units
				(in thousands)
May 15, 2012	March 31, 2012	$ 0.12[(1)]	$ 3,144	$ 64
August 14, 2012	June 30, 2012	$ 0.40	$ 12,891	$ 263

(1) Represents a pro-rated cash distribution of $0.40 per common limited partner unit for the period from March 5, 2012, the date ATLS exploration and production assets were transferred to the Partnership, to March 31, 2012.

On October 25, 2012, the Partnership declared a cash distribution of $0.43 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2012. The $17.5 million distribution, including $0.4 million and $1.7 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2012 to unitholders of record at the close of business on November 5, 2012.

NOTE 14 BENEFIT PLAN

2012 Long-Term Incentive Plan

The Partnership s 2012 Long-Term Incentive Plan (2012 LTIP), effective March 2012, provides incentive awards to officers, employees and directors and employees of the general partner and its affiliates, consultants and joint venture partners (collectively, the Participants) who perform services for the Partnership. The 2012 LTIP is administered by the board of the general partner, a committee of the board or the board (or committee of the board) of an affiliate (the LTIP Committee). Under the 2012 LTIP, the LTIP Committee may grant awards of phantom units, restricted units or unit options for an aggregate of 2,900,000 common limited partner units. At September 30, 2012, the Partnership had 2,454,476 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 445,524 phantom units, restricted units and unit options available for grant.

Upon a change in control , as defined in the 2012 LTIP, all unvested awards held by directors will immediately vest in full. In the case of awards held by eligible employees, upon the eligible employee s termination of employment without cause , as defined in the 2012 LTIP, or upon any other type of termination specified in the eligible employee s applicable award agreement(s), in any case following a change in control, any unvested award will immediately vest in full and, in the case of options, become exercisable for the one-year period following the date of termination of employment, but in any case not later than the end of the original term of the option.

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In connection with a change in control, the LTIP Committee, in its sole and absolute discretion and without obtaining the approval or consent of the unitholders or any participant, but subject to the terms of any award agreements and employment agreements to which the general partner (or any affiliate) and any participant are party, may take one or more of the following actions (with discretion to differentiate between individual participants and awards for any reason):

cause awards to be assumed or substituted by the surviving entity (or affiliate of such surviving entity);

accelerate the vesting of awards as of immediately prior to the consummation of the transaction that constitutes the change in control so that awards will vest (and, with respect to options, become exercisable) as to the common units that otherwise would have been unvested so that participants (as holders of awards granted under the new equity plan) may participate in the transaction;

provide for the payment of cash or other consideration to participants in exchange for the cancellation of outstanding awards (in an amount equal to the fair market value of such cancelled awards);

terminate all or some awards upon the consummation of the change-in-control transaction, but only if the LTIP Committee provides for full vesting of awards immediately prior to the consummation of such transaction; and

make such other modifications, adjustments or amendments to outstanding awards or the new equity plan as the LTIP Committee deems necessary or appropriate.

Phantom Units

Phantom units represent rights to receive a common unit, an amount of cash or other securities or property based on the value of a common unit, or a combination of common units and cash or other securities or property. Phantom units are subject to terms and conditions determined by the LTIP Committee, which may include vesting restrictions. In tandem with phantom unit grants, the LTIP Committee may grant distribution equivalent rights (DERs), which are the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by the Partnership with respect to a common unit during the period that the underlying phantom unit is outstanding. Through September 30, 2012, phantom units granted under the 2012 LTIP generally will vest 25% of the original granted amount on each of the next four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at September 30, 2012, 210,993 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at September 30, 2012 include DERs. During the three and nine months ended September 30, 2012, respectively, the Partnership paid $0.3 million with respect to the 2012 LTIP s DERs. No amounts were paid during the three and nine months ended September 30, 2011, respectively, with respect to the DERs. These amounts were recorded as reductions of partners capital on the Partnership s consolidated combined balance sheet.

The following table sets forth the 2012 LTIP phantom unit activity for the periods indicated:

	Three Months Ended September 30,			
	2012		2011	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of period	810,476	$ 24.69		$
Granted	129,500	25.23		
Vested[(1)]				
Forfeited	(1,000)	24.67		

Outstanding, end of period[(2)(3)]	938,976	$ 24.76	$
Non-cash compensation expense recognized (in thousands)		$ 2,915	$

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	Nine Months Ended September 30,			
	2012		2011	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year		$		$
Granted	939,976	24.76		
Vested[(1)]				
Forfeited	(1,000)	24.67		
Outstanding, end of period[(2)(3)]	938,976	$ 24.76		$
Non-cash compensation expense recognized (in thousands)		$ 4,655		$

(1) No phantom unit awards vested during the three and nine months ended September 30, 2012 and 2011.

(2) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2012 was $24.0 million.

(3) There was $23,000 classified within accrued liabilities on the Partnership s consolidated combined balance sheet at September 30, 2012, representing 3,476 units, due to the option of the participants to settle in cash instead of units. No amounts were classified within accrued liabilities on the Partnership s consolidated combined balance sheet at December 31, 2011. The respective weighted average grant date fair value for these units was $28.75 at September 30, 2012.

At September 30, 2012, the Partnership had approximately $8.6 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards.

Unit Options

A unit option is the right to purchase a Partnership common unit in the future at a predetermined price (the exercise price). The exercise price of each option is determined by the LTIP Committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The LTIP Committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method by which the exercise price may be paid by the Participant. Unit option awards expire 10 years from the date of grant. Through September 30, 2012, unit options granted under the 2012 LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. There were 378,875 unit options outstanding under the 2012 LTIP at September 30, 2012 that will vest within the following twelve months. No cash was received from the exercise of options for the three and nine months ended September 30, 2012 and 2011.

The following table sets forth the 2012 LTIP unit option activity for the periods indicated:

	Three Months Ended September 30,			
	2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	1,499,500	$ 24.67		$
Granted	18,000	25.18		
Exercised[(1)]				
Forfeited	(2,000)	24.67		
Outstanding, end of period[(2)(3)]	1,515,500	$ 24.68		$
Options exercisable, end of period[(4)]		$		$

Non-cash compensation expense recognized (in thousands)	$ 1,927	$

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	Nine Months Ended September 30, 2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of year		$		$
Granted	1,517,500	24.68		
Exercised[(1)]				
Forfeited	(2,000)	24.67		
Outstanding, end of period[(2)(3)]	1,515,500	$ 24.68		$
Options exercisable, end of period[(4)]		$		$
Non-cash compensation expense recognized (in thousands)		$ 3,201		$

(1) No options were exercised during the three and nine months ended September 30, 2012 and 2011.
(2) The weighted average remaining contractual life for outstanding options at September 30, 2012 was 9.6 years.
(3) The aggregate intrinsic value of options outstanding at September 30, 2012 was approximately $1.3 million.
(4) No options were exercisable at September 30, 2012.

At September 30, 2012, the Partnership had approximately $11.6 million in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards. The Partnership used the Black-Scholes option pricing model to estimate the weighted average fair value of options granted. The following weighted average assumptions were used for the periods indicated:

	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Expected dividend yield	2.5%	1.5%
Expected unit price volatility	46.0%	47.0%
Risk-free interest rate	0.8%	1.0%
Expected term (in years)	6.25	6.25
Fair value of unit options granted	$ 8.72	$ 9.78

Restricted Units

Restricted units are actual common units issued to a participant that are subject to vesting restrictions and evidenced in such manner as the LTIP Committee may deem appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the LTIP Committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both. A holder of restricted units will have certain rights of holders of common units in general, including the right to vote the restricted units. However, during the period during which the restricted units are subject to vesting restrictions, the holder will not be permitted to sell, assign, transfer, pledge or otherwise encumber the restricted units.

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NOTE 15 OPERATING SEGMENT INFORMATION

The Partnership s operations include three reportable operating segments. These operating segments reflect the way the Partnership manages its operations and makes business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Gas and oil production:				
Revenues	$ 24,699	$ 16,305	$ 61,323	$ 51,654
Operating costs and expenses	(7,295)	(3,990)	(16,247)	(11,953)
Depreciation, depletion and amortization expense	(12,576)	(6,882)	(29,663)	(20,626)
Segment income	$ 4,828	$ 5,433	$ 15,413	$ 19,075
Well construction and completion:				
Revenues	$ 36,317	$ 35,657	$ 92,277	$ 64,336
Operating costs and expenses	(31,581)	(30,449)	(79,882)	(54,754)
Segment income	$ 4,736	$ 5,208	$ 12,395	$ 9,582
Other partnership management:(1)				
Revenues	$ 13,727	$ 11,628	$ 29,289	$ 34,057
Operating costs and expenses	(6,790)	(6,923)	(20,261)	(22,454)
Depreciation, depletion and amortization expense	(1,342)	(1,189)	(4,185)	(3,393)
Segment income	$ 5,595	$ 3,516	$ 4,843	$ 8,210
Reconciliation of segment income to net income (loss):				
Segment income:				
Gas and oil production	$ 4,828	$ 5,433	$ 15,413	$ 19,075
Well construction and completion	4,736	5,208	12,395	9,582
Other partnership management	5,595	3,516	4,843	8,210
Total segment income	15,159	14,157	32,651	36,867
General and administrative expenses(2)	(16,147)	(4,757)	(48,427)	(12,275)
Chevron transaction expense(2)	(7,670)		(7,670)	
Gain (loss) on asset sales and disposal(2)	2		(7,019)	48
Interest expense(2)	(1,423)		(2,529)	
Net income (loss)	$ (10,079)	$ 9,400	$ (32,994)	$ 24,640
Capital expenditures				
Gas and oil production	$ 25,703	$ 20,581	$ 65,882	$ 29,053
Other partnership management	242	776	1,260	3,207
Corporate and other	1,782	531	6,237	4,010
Total capital expenditures	$ 27,727	$ 21,888	$ 73,379	$ 36,270

	September 30, 2012	December 31, 2011
Balance sheet		
Goodwill:		
Gas and oil production	$ 18,145	$ 18,145
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	$ 31,784	$ 31,784
Total assets:		
Gas and oil production	$ 1,040,213	$ 593,320
Well construction and completion	7,097	6,987
Other partnership management	53,969	44,981
Corporate and other	37,663	55,825
	$ 1,138,942	$ 701,113

(1) Includes revenues and expenses from well services, gathering and processing, administration and oversight and other, net that do not meet the quantitative threshold for reporting segment information.

(2) The Partnership notes that gain (loss) on asset sales and disposal, general and administrative expenses, Chevron transaction expense and interest expense have not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

NOTE 16 SUBSEQUENT EVENTS

Cash Distribution. On October 25, 2012, the Partnership declared a cash distribution of $0.43 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2012. The $17.5 million distribution, including $0.4 million and $1.7 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2012 to unitholders of record at the close of business on November 5, 2012.

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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. Risk Factors , in our annual report on Form 10-K for the year ended December 31, 2011. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

BUSINESS OVERVIEW

We are a publicly-traded Delaware master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas and oil, with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships, in which we coinvest, to finance a portion of our natural gas and oil production activities.

At September 30, 2012, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of our general partner Class A units and incentive distribution rights through which it manages and effectively controls us, and an approximate 51.5% limited partnership ownership interest (20,960,000 limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS exploration and production assets (the Atlas Energy E&P Operations), which were transferred to us on March 5, 2012. In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million of our common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 of our limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of our limited partner units represented approximately 20% of the common limited partner units outstanding.

On February 17, 2011, ATLS acquired certain assets and liabilities (the Transferred Business) from Atlas Energy, Inc. (AEI), the former owner of ATLS general partner. These assets principally included the following exploration and production assets which were included within Atlas Energy s E&P Operations:

AEI s investment management business, which sponsors tax-advantaged direct investment natural gas and oil partnerships, through which we fund a portion of our natural gas and oil well drilling;

proved reserves located in the Appalachia Basin, the Niobrara formation in Colorado, the New Albany Shale of west central Indiana, the Antrim Shale of northern Michigan, and the Chattanooga Shale of northeastern Tennessee; and

certain producing natural gas and oil properties, upon which we are developers and producers.

FINANCIAL PRESENTATION

Our consolidated combined balance sheet at September 30, 2012, the statement of operations for the three months ended September 30, 2012, and the portion of the consolidated combined statement of operations for the nine months ended September 30, 2012 subsequent to the transfer of assets on March 5, 2012 include our accounts and our wholly-owned subsidiaries. Our combined balance sheet at December 31, 2011, the portion of the consolidated combined statements of operations for the nine months ended September 30, 2012 prior to the transfer of assets on March 5, 2012 and the combined statement of operations for the three and nine months ended September 30, 2011 were derived from the separate records maintained by ATLS and may not necessarily be indicative of the conditions that would have existed if we had been operated as an unaffiliated entity. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated combined balance sheets and related consolidated combined statements of operations. Such estimates included allocations made from the historical accounting records of ATLS, based on management s best estimates, in order to derive our financial statements for the periods presented prior to the transfer of assets. Actual balances and results could be different from those estimates.

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Upon the acquisition of the Transferred Business on February 17, 2011, ATLS management determined that the acquisition constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable assets and liabilities of the Transferred Business with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the Transferred Business would have been included in our consolidated combined financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect of the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior year financial statements to furnish comparative information. As such, we reflected the impact of the acquisition of the Transferred Business on our consolidated combined financial statements in the following manner:

Recognized the assets acquired and liabilities assumed from the Transferred Business at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners capital/equity;

Retrospectively adjusted our consolidated combined financial statements for any date prior to February 17, 2011, the date of acquisition, to reflect our results on a consolidated combined basis with the results of the Transferred Business as of or at the beginning of the respective period; and

Adjusted the presentation of our consolidated combined statements of operations for any date prior to February 17, 2011 to reflect the results of operations attributable to the Transferred Business as a reduction of net income (loss) to determine income (loss) attributable to common limited partners and the general partner. The Transferred Business historical financial statements prior to the date of acquisition reflect an allocation of general and administrative expenses determined by AEI to the underlying business segments, including the Transferred Business. We have reviewed AEI s general and administrative expense allocation methodology, which is based on the relative total assets of AEI and the Transferred Business, for the Transferred Business historical financial statements prior to the date of acquisition and believe the methodology is reasonable and reflects the approximate general and administrative costs of our underlying business segments.

SUBSEQUENT EVENTS

Cash Distribution. On October 25, 2012, we declared a cash distribution of $0.43 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2012. The $17.5 million distribution, including $0.4 million and $1.7 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2012 to unitholders of record at the close of business on November 5, 2012.

RECENT DEVELOPMENTS

Acquisition of Titan Operating, L.L.C. On July 25, 2012, we completed the acquisition of Titan Operating, L.L.C. (Titan) in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had a collective value of $193.2 million, based upon the closing price of our publicly traded units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Issuance of Units). Through the acquisition of Titan, we acquired interests in approximately 52 proved developed natural gas wells and approximately 250 Bcfe of proved reserves and 700 Bcfe of proved, probable and possible reserves and associated assets in the Barnett Shale, located in the Bend Arch Fort Worth Basin in North Texas. Also, we entered into an amendment to our senior secured revolving credit facility on July 26, 2012 to increase the borrowing base from $250.0 million to $310.0 million. The cash paid at closing was funded through borrowings under our credit facility (see Credit Facility). The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act) (see Issuance of Units).

Acquisition of Assets from Carrizo Oil & Gas, Inc. On April 30, 2012, we acquired certain oil and natural gas assets from Carrizo Oil & Gas, Inc. (NASDAQ: CRZO; Carrizo) for approximately $187.0 million in cash. The assets acquired include interests in approximately 200 producing natural gas wells from the Barnett Shale, located in Bend Arch Fort Worth Basin in North Texas, proved undeveloped acres also in the Barnett Shale and gathering pipelines and associated gathering facilities that service certain of the acquired wells. The purchase price was funded through borrowing under our credit

facility and $119.5 million of net proceeds from the sale of 6.0 million of our common units at a negotiated purchase price per unit of $20.00, of which $5.0 million was purchased by certain of our executives. The common units were issued in a private transaction exempt from registration under Section 4 (2) of the Securities Act (see Issuance of Units).

Equal Acquisition. In April 2012, we acquired a 50% interest in approximately 14,500 net undeveloped acres in the oil and NGL area of the Mississippi Lime play in northwestern Oklahoma for $18.0 million from subsidiaries of Equal Energy, Ltd. (Equal) (NYSE: EQU; TSX: EQU). The transaction was funded through borrowings under our revolving credit facility (see Credit Facility). Concurrent with the purchase of acreage, we and Equal entered into a participation and development agreement for future drilling in the Mississippi Lime play. We served as the drilling and completion operator, while Equal undertook production operations, including water disposal. In September 2012, we acquired Equal s remaining 50% interest in the undeveloped acres, as well as approximately 8 Mmcfed of net production in the Mississippi Lime region and salt water disposal infrastructure for $41.3 million, including $1.3 million related to certain post-closing adjustments. The additional acquisition was subject to certain post-closing adjustments and funded with available borrowings under our revolving credit facility (see Credit Facility). As a result of our acquisition of Equal s remaining interest in the undeveloped acres, the existing joint venture agreement between us and Equal in the Mississippi Lime position was terminated and all infrastructure associated with the assets, principally the salt water disposal system, is operated by us.

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. We market the majority of our natural gas production to gas utility companies, gas marketers, local distribution companies and industrial or other end-users. The sales price of natural gas produced is a function of the market in the area and typically tied to a regional index. The production area and pricing indexes are as follows: Appalachian Basin and Mississippi Lime, primarily the NYMEX spot market price; Barnett Shale, primarily the Waha spot market price; New Albany Shale and Antrim Shale, primarily the Texas Gas Zone SL and Chicago Hub spot market prices; and Niobrara formation, primarily the Cheyenne Hub spot market price.

Crude Oil. Crude oil produced from our wells flows directly into storage tanks where it is picked up by an oil company, a common carrier or pipeline companies acting for an oil company, which is purchasing the crude oil. We sell any oil produced at the prevailing spot market price in each region.

Natural Gas Liquids. Natural gas liquids (NGL s) are extracted from the natural gas stream by processing and fractionation plants enabling the remaining dry gas (low BTU content) to meet pipeline specifications for long-haul transport to end users. We sell our NGL production at the prevailing spot market price for NGLs.

We do not have delivery commitments for fixed and determinable quantities of natural gas, oil or NGLs in any future periods under existing contracts or agreements.

Investment Partnerships. We generally have funded a portion of our drilling activities through sponsorship of tax-advantaged investment drilling partnerships. In addition to providing capital for our drilling activities, our investment partnerships are a source of fee-based revenues, which are not directly dependent on commodity prices. As managing general partner of the investment partnerships, we receive the following fees:

- *Well construction and completion.* For each well that is drilled by an investment partnership, we receive a 15% to 18% mark-up on those costs incurred to drill and complete the well;

- *Administration and oversight.* For each well drilled by an investment partnership, we receive a fixed fee between $15,000 and $400,000, depending on the type of well drilled. Additionally, the partnership pays us a monthly per well administrative fee of $75 for the life of the well. Because we coinvest in the partnerships, the net fee that we receive is reduced by our proportionate interest in the well;

- *Well services*. Each partnership pays us a monthly per well operating fee, currently $100 to $2,000, for the life of the well. Because we coinvest in the partnerships, the net fee that we receive is reduced by our proportionate interest in the wells; and

Gathering. Each royalty owner, partnership and certain other working interest owners pay us a gathering fee, which generally ranges from $0.35 per Mcf to the amount of the competitive gathering fee, currently defined as 13% of the gross sales price of the natural gas. In general, pursuant to gathering agreements we have with a third-party gathering system which gathers the majority of our natural gas, we must also pay an additional amount equal to the excess of the gathering fees collected from the investment partnerships up to an amount equal to approximately 16% of the realized natural gas sales price (adjusted for the settlement of natural gas derivative instruments). As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from investment partnerships by approximately 3%.

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GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by the following key trends. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about or interpretations of available information prove to be incorrect, our actual results may vary materially from our expected results.

The areas in which we operate are experiencing a significant increase in natural gas, oil and NGL production related to new and increased drilling for deeper natural gas formations and the implementation of new exploration and production techniques, including horizontal and multiple fracturing techniques. The increase in the supply of natural gas has put a downward pressure on domestic prices. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments by third parties in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, our ability to make payments on our revolving credit facility and our ability to make distributions to our unitholders, including ATLS, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas and oil prices. As initial reservoir pressures are depleted, natural gas production from particular wells decreases. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce.

RESULTS OF OPERATIONS

GAS AND OIL PRODUCTION

Production Profile. Currently, we have focused our natural gas and oil production operations in various shale plays throughout the United States. As part of ATLS agreement with AEI to acquire the Transferred Business on February 17, 2011, we have certain agreements which restrict our ability to drill additional wells in certain areas of Pennsylvania, New York and West Virginia, including portions of the Marcellus Shale. Through September 30, 2012, we have established production positions in the following areas:

- the Appalachia basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas; the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region; and the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone;

- the Barnett Shale in the Bend Arch Fort Worth Basin in northern Texas, a hydro-carbon producing shale in which we established a position following our acquisitions of assets from Carrizo and Titan during 2012 (see Recent Developments);

- the Mississippi Lime play in northwestern Oklahoma, an oil and natural gas liquids rich area, in which we established a position following our acquisitions from Equal during 2012 (see Recent Developments);

- the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas;

- the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; and

- the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale.

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The following table presents the number of wells we drilled, both gross and for our interest, and the number of gross wells we turned in line during the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Gross wells drilled:				
Appalachia	8	9	22	12
Barnett	9		9	
Mississippi Lime	2		4	
Niobrara		33	51	50
	19	42	86	62
Our share of gross wells drilled[1]:				
Appalachia	2	2	6	3
Barnett	8		8	
Mississippi Lime			1	
Niobrara		6	15	12
	10	8	30	15
Gross wells turned in line:				
Appalachia	13		46	1
Barnett	3		3	
Mississippi Lime	2		2	
New Albany/Antrim				13
Niobrara	26	7	98	37
	44	7	149	51

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in our investment partnerships.

Production Volumes. The following table presents our total net natural gas, oil, and natural gas liquids production volumes and production per day for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Production:[1][2]				
Appalachia:[3]				
Natural gas (MMcf)	3,642	2,492	9,661	7,689
Oil (000 s Bbls)	25	27	79	81
Natural gas liquids (000 s Bbls)	38	38	116	122

Total (MMcfe)	4,022	2,880	10,832	8,910
Barnett:[4]				
Natural gas (MMcf)	4,055		5,830	
Oil (000 s Bbls)				
Natural gas liquids (000 s Bbls)	60		63	
Total (MMcfe)	4,417		6,210	
Mississippi Lime:[5]				
Natural gas (MMcf)	59		59	
Oil (000 s Bbls)				
Natural gas liquids (000 s Bbls)				
Total (MMcfe)	59		59	
New Albany/Antrim:				
Natural gas (MMcf)	286	283	837	866
Total (MMcfe)	286	283	837	866
Niobrara:				
Natural gas (MMcf)	73	42	198	95
Total (MMcfe)	73	42	198	95
Total:				
Natural gas (MMcf)	8,115	2,818	16,586	8,651
Oil (000 s Bbls)	25	27	80	81
Natural gas liquids (000 s Bbls)	98	38	179	122
Total (MMcfe)	8,857	3,206	18,136	9,871

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Production per day: [1][2]				
Appalachia:[3]				
Natural gas (Mcfd)	39,583	27,088	35,260	28,166
Oil (Bpd)	275	294	290	297
Natural gas liquids (Bpd)	414	408	422	448
Total (Mcfed)	43,716	31,304	39,533	32,637
Barnett:[4]				
Natural gas (Mcfd)	49,440		21,278	
Oil (Bpd)	2		1	
Natural gas liquids (Bpd)	865		230	
Total (Mcfed)	54,642		22,663	
Mississippi Lime:[5]				
Natural gas (Mcfd)	7,391		216	
Oil (Bpd)				
Natural gas liquids (Bpd)				
Total (Mcfed)	7,391		216	
New Albany/Antrim:				
Natural gas (Mcfd)	3,111	3,081	3,054	3,172
Total (Mcfed)	3,111	3,081	3,054	3,172
Niobrara:				
Natural gas (Mcfd)	792	461	723	349
Total (Mcfed)	792	461	723	349
Total: [4][5]				
Natural gas (Mcfd)	88,208	30,629	60,531	31,687
Oil (Bpd)	277	294	291	297
Natural gas liquids (Bpd)	1,067	408	652	448
Total (Mcfed)	96,275	34,845	66,189	36,158

(1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the investment partnerships in which we have an interest, based on our equity interest in each such partnership and based on each partnership s proportionate net revenue interest in these wells.

(2) MMcf represents million cubic feet; MMcfe represent million cubic feet equivalents; Mcfd represents thousand cubic feet per day; Mcfed represents thousand cubic feet equivalents per day; and Bbls and Bpd represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately six Mcf s to one barrel.

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia and Tennessee.

(4) Volumetric production per day for Barnett for the three months ended September 30, 2012 includes production per day associated with the Titan operational assets for the 68-day period from July 25, 2012, the date of acquisition, through September 30, 2012. Total Barnett production per day for the nine months ended September 30, 2012 represents Barnett volume production for the full 274-day period. Total production per day represents total production volume over the 92 and 274 days within the three and nine months ended September 30, 2012, respectively.

(5)

Volumetric production per day for Mississippi Lime for the three months ended September 30, 2012 includes production per day associated with the acquisition of the remaining 50% interest in Equal s operational assets for the 7-day period from September 24, 2012, the date of acquisition, through September 30, 2012. Total Mississippi Lime production per day for the nine months ended September 30, 2012 represents volume production for the full 274-day period. Total production per day represents total production volume over the 92 and 274 days within the three and nine months ended September 30, 2012, respectively.

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Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas, which comprised 94% of our proved reserves on an energy equivalent basis at December 31, 2011. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the three and nine months ended September 30, 2012 and 2011, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Production revenues (in thousands):				
Appalachia:[1]				
Natural gas revenue	$ 8,776	$ 10,726	$ 29,993	$ 33,888
Oil revenue	2,223	2,255	7,601	7,341
Natural gas liquids revenue	895	1,861	4,148	5,930
Total revenues	$ 11,894	$ 14,842	$ 41,742	$ 47,159
Barnett:				
Natural gas revenue	$ 9,666	$	$ 13,606	$
Oil revenue	16		18	
Natural gas liquids revenue	1,620		1,767	
Total revenues	$ 11,302	$	$ 15,391	$
Mississippi Lime:				
Natural gas revenue	$ 112	$	$ 112	$
Oil revenue				
Natural gas liquids revenue				
Total revenues	$ 112	$	$ 112	$
New Albany/Antrim:				
Natural gas revenue	$ 1,108	$ 1,272	$ 3,398	$ 4,041
Total revenues	$ 1,108	$ 1,272	$ 3,398	$ 4,041
Niobrara:				
Natural gas revenue	$ 283	$ 191	$ 680	$ 454
Total revenues	$ 283	$ 191	$ 680	$ 454
Total:				
Natural gas revenue	$ 19,945	$ 12,189	$ 47,789	$ 38,383
Oil revenue	2,239	2,255	7,619	7,341
Natural gas liquids revenue	2,515	1,861	5,915	5,930
Total revenues	$ 24,699	$ 16,305	$ 61,323	$ 51,654
Average sales price:[2]				
Natural gas (per Mcf):				
Total realized price, after hedge[3]	$ 3.01	$ 5.10	$ 3.42	$ 5.24
Total realized price, before hedge[3]	$ 2.46	$ 4.90	$ 2.60	$ 4.69

Oil (per Bbl):				
Total realized price, after hedge	$ 87.86	$ 83.34	$ 95.70	$ 90.65
Total realized price, before hedge	$ 84.30	$ 81.85	$ 93.38	$ 89.79
Natural gas liquids (per Bbl) total realized price:	$ 25.61	$ 49.52	$ 33.09	$ 48.43
Production costs (per Mcfe):[2]				
Appalachia:[1]				
Lease operating expenses[4]	$ 0.95	$ 1.11	$ 0.94	$ 1.03
Production taxes	0.07	0.05	0.08	0.05
Transportation and compression	0.39	0.51	0.34	0.49
	$ 1.41	$ 1.67	$ 1.36	$ 1.57
Barnett:				
Lease operating expenses	$ 0.55	$	$ 0.51	$
Production taxes	0.18		0.19	
Transportation and compression	0.15		0.19	
	$ 0.88	$	$ 0.88	$
Mississippi Lime:				
Lease operating expenses	$	$	$	$
Production taxes				
Transportation and compression				
	$	$	$	$
New Albany/Antrim:				
Lease operating expenses	$ 1.08	$ 1.13	$ 1.11	$ 1.19
Production taxes	0.10	0.14	0.10	0.12
Transportation and compression	0.02	(0.11)	0.03	0.03
	$ 1.20	$ 1.15	$ 1.23	$ 1.35
Niobrara:				
Lease operating expenses	$ 0.73	$ 1.51	$ 1.04	$ 1.02
Production taxes	0.03	0.02	0.12	0.02
Transportation and compression	0.41	0.73	0.40	0.46
	$ 1.17	$ 2.27	$ 1.56	$ 1.50
Total:				
Lease operating expenses[4]	$ 0.75	$ 1.12	$ 0.80	$ 1.05
Production taxes	0.13	0.06	0.12	0.05
Transportation and compression	0.25	0.46	0.27	0.45
	$ 1.13	$ 1.63	$ 1.19	$ 1.55

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(1) Appalachia includes our operations located in Pennsylvania, Ohio, New York, West Virginia and Tennessee.

(2) Mcf represents thousand cubic feet; Mcfe represents thousand cubic feet equivalents; and Bbl represents barrels.

(3) Excludes the impact of subordination of our production revenue to investor partners within our investment partnerships for the three and nine months ended September 30, 2012 and 2011. Including the effect of this subordination, the average realized gas sales price was $2.46 per Mcf ($1.91 per Mcf before the effects of financial hedging) and $4.33 per Mcf ($4.13 per Mcf before the effects of financial hedging) for the three months ended September 30, 2012 and 2011, respectively, and $2.88 per Mcf ($2.07 per Mcf before the effects of financial hedging) and $4.44 per Mcf ($3.89 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2012 and 2011, respectively.

(4) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our investment partnerships for the three and nine months ended September 30, 2012 and 2011. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.29 per Mcfe ($0.75 per Mcfe for total production costs) and $0.68 per Mcfe ($1.24 per Mcfe for total production costs) for the three months ended September 30, 2012 and 2011, respectively, and $0.45 per Mcfe ($0.87 per Mcfe for total production costs) and $0.66 per Mcfe ($1.19 per Mcfe for total production costs) for the nine months ended September 30, 2012 and 2011, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $0.45 per Mcfe ($0.83 per Mcfe for total production costs) and $0.73 per Mcfe ($1.24 per Mcfe for total production costs) for three months ended September 30, 2012 and 2011, respectively, and were $0.51 per Mcfe ($0.90 per Mcfe for total production costs) and $0.71 per Mcfe ($1.21 per Mcfe for total production costs) for the nine months ended September 30, 2012 and 2011, respectively.

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Total natural gas revenues were $19.9 million for the three months ended September 30, 2012, an increase of $7.7 million from $12.2 million for the three months ended September 30, 2011. This increase consisted of a $14.0 million increase attributable to higher production volumes, including $9.7 million associated with the newly acquired Barnett Shale assets, partially offset by a $4.0 million decrease attributable to lower realized natural gas prices for production volume on legacy systems wells and a $2.3 million increase in gas revenues subordinated to the investor partners within our investment partnerships for the three months ended September 30, 2012 compared with the prior year period. Total oil revenues were $2.2 million for the three months ended September 30, 2012, comparable with the prior year period. Total natural gas liquids revenues were $2.5 million for the three months ended September 30, 2012, an increase of $0.6 million from $1.9 million for the comparable prior year period due primarily to a $1.6 million increase attributable to liquids production associated with the newly acquired Barnett Shale assets, partially offset by a $1.0 million decrease due primarily to lower average natural gas liquids realized prices associated with legacy systems natural gas liquids production.

Appalachia production costs were $3.0 million for the three months ended September 30, 2012, a decrease of $0.6 million from $3.6 million for the three months ended September 30, 2011. This decrease was principally due to a $1.5 million increase in our credit received against lease operating expenses pertaining to the subordination of our revenue within our investment partnerships, partially offset by a $0.9 million increase in water hauling and disposal costs and other production costs due to timing of costs incurred. Production costs associated with our newly acquired Barnett Shale assets were $3.9 million for the three months ended September 30, 2012.

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Total natural gas revenues were $47.8 million for the nine months ended September 30, 2012, an increase of $9.4 million from $38.4 million for the nine months ended September 30, 2011. This increase consisted of a $24.3 million increase attributable to higher production volumes, including $13.6 million associated with the newly acquired Barnett Shale assets, partially offset by a $13.0 million decrease attributable to lower realized natural gas prices for production volume on legacy systems wells and a $1.9 million increase in gas revenues subordinated to the investor partners within our investment partnerships for the nine months ended September 30, 2012 compared with the prior year period. Total oil revenues were $7.6 million for the nine months ended September 30, 2012, an increase of $0.3 million from $7.3 million for the comparable prior year period due primarily to higher average oil realized prices during the current year period. Total natural gas liquids revenues were $5.9 million for the nine months ended September 30, 2012, comparable with the prior year period.

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Appalachia production costs were $9.4 million for the nine months ended September 30, 2012, a decrease of $1.3 million from $10.7 million for the nine months ended September 30, 2011. This decrease was principally due to a $1.9 million increase in our credit received against lease operating expenses pertaining to the subordination of our revenue within our investment partnerships, partially offset by a $0.3 million increase in water hauling and disposal costs due to timing of costs incurred and a $0.3 million increase in labor and other costs. Production costs associated with our newly acquired Barnett Shale assets were $5.5 million for the nine months ended September 30, 2012.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our investment partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. The following table presents the amounts of drilling partnership investor capital raised and deployed (in thousands), as well as the number of gross and net development wells we drilled for our investment partnerships during the three and nine months ended September 30, 2012 and 2011. There were no exploratory wells drilled during the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Drilling partnership investor capital:				
Raised	$ 23,110	$ 32,459	$ 26,110	$ 32,459
Deployed	$ 36,317	$ 35,657	$ 92,277	$ 64,336
Gross partnership wells drilled:				
Appalachia	8	9	22	12
Mississippi Lime	2		4	
Niobrara		33	51	50
Total	10	42	77	62
Net partnership wells drilled:				
Appalachia	8	8	22	11
Mississippi Lime	2		3	
Niobrara		33	51	50
Total	10	41	76	61

Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for investment partnerships we sponsor. The following table sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Average construction and completion:				
Revenue per well	$ 6,701	$ 1,198	$ 1,099	$ 1,075
Cost per well	5,827	1,023	951	915
Gross profit per well	$ 874	$ 175	$ 148	$ 160

Gross profit margin	$ 4,736	$ 5,208	$ 12,395	$ 9,582
Partnership net wells associated with revenue recognized[(1)]:				
Appalachia	3	5	18	8
Mississippi Lime	2		3	
New Albany/Antrim				3
Niobrara		25	63	49
	5	30	84	60

(1) Consists of partnership net wells for which well construction and completion revenue was recognized on a percentage of completion basis.

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Well construction and completion segment margin was $4.7 million for the three months ended September 30, 2012, a decrease of $0.5 million from $5.2 million for the three months ended September 30, 2011. This decrease consisted of a $4.3 million decrease related to a decreased number of wells recognized for revenue within our investment partnerships, partially offset by a $3.8 million increase associated with higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed in Appalachia for Marcellus Shale and Utica Shale wells within the drilling partnerships during third quarter 2012. As our drilling contracts with the investment partnerships are on a cost-plus basis, an increase or decrease in the average cost per well also results in a proportionate increase or decrease in the average revenue per well, which directly affects the number of wells we drill.

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Well construction and completion segment margin was $12.4 million for the nine months ended September 30, 2012, an increase of $2.8 million from $9.6 million for the nine months ended September 30, 2011. This increase consisted of a $3.6 million increase related to an increased number of wells recognized for revenue within our investment partnerships, partially offset by a $0.8 million decrease associated with lower gross profit margin per well. Average revenue and cost per well increased between periods due to higher capital deployed for Marcellus Shale and Utica Shale wells within the drilling partnerships during the first nine months of 2012. In addition, the increase in well construction and completion margin was due to the deployment of funds raised from our Fall 2011 drilling program in comparison to the Fall 2010 drilling program, which was cancelled following AEI s announcement of the acquisition of the Transferred Business in November 2010.

Our consolidated combined balance sheet at September 30, 2012 includes $5.6 million of liabilities associated with drilling contracts for funds raised by our investment partnerships that have not been applied to the completion of wells due to the timing of drilling operations, and thus had not been recognized as well construction and completion revenue on our consolidated combined statements of operations. We expect to recognize this amount as revenue during the remainder of 2012 and the first half of 2013.

Administration and Oversight

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our investment partnerships.

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Administration and oversight fee revenues were $4.4 million for the three months ended September 30, 2012, an increase of $2.1 million from $2.3 million for the three months ended September 30, 2011. This increase was primarily due to horizontal wells drilled in both the Mississippi Lime Shale and Utica Shale, which have higher fees per well, during the current year period.

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Administration and oversight fee revenues were $8.6 million for the nine months ended September 30, 2012, an increase of $3.5 million from $5.1 million for the nine months ended September 30, 2011. This increase was primarily due to horizontal wells drilled in both the Mississippi Lime Shale and Utica Shale during the current year period and an increase in the number of Marcellus Shale and Niobrara Shale wells drilled during the current year period in comparison to the prior year period, primarily as a result of the wells drilled as part of our Fall 2011 drilling program compared with the Fall 2010 drilling program. The planned Fall 2010 drilling program was cancelled following AEI s announcement of the acquisition of the Transferred Business in November 2010.

Well Services

Well service revenue and expenses represent the monthly operating fees we charge and the work our service company performs for our investment partnership wells during the drilling and completing phase as well as ongoing maintenance of these wells and other wells in which we serve as operator.

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Well services revenues were $5.1 million for the three months ended September 30, 2012, an increase of $0.2 million from $4.9 million for three months ended September 30, 2011. Well services expenses were $2.2 million for the three months ended September 30, 2012, an increase of $0.2 million from $2.0 million for the three months ended September 30, 2011. The increase in well services revenue is primarily related to higher equipment rental revenue during the three months ended September 30, 2012 as compared with the comparable prior year period. The increase in well services expenses is primarily related to higher well labor costs.

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Well services revenues were $15.3 million for the nine months ended September 30, 2012, an increase of $0.2 million from $15.1 million for the nine months ended September 30, 2011. Well services expenses were $7.1 million for the nine months ended September 30, 2012, an increase of $1.0 million from $6.1 million for the nine months ended September 30, 2011. The increase in well services revenue is primarily related to higher equipment rental revenue during the nine months ended September 30, 2012 as compared with the comparable prior year period. The increase in well services expenses is primarily related to higher well labor costs.

Gathering and Processing

Gathering and processing margin includes gathering fees we charge to our investment partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. The gathering fees charged to our Drilling Partnership wells generally range from $0.35 per Mcf to the amount of the competitive gathering fee, currently defined as 13% of the gross sales price of the natural gas. In general, pursuant to gathering agreements we have with a third-party gathering system which gathers the majority of our natural gas, we must also pay an additional amount equal to the excess of the gathering fees collected from the investment partnerships up to an amount equal to approximately 16% of the realized natural gas sales price (adjusted for the settlement of natural gas derivative instruments). However, in most of our Drilling Partnerships, we collect a gathering fee of 13% of the realized natural gas sales price per the respective partnership agreement. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the investment partnerships by approximately 3%.

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Our net gathering and processing expense for the three months ended September 30, 2012 was $0.4 million, which was comparable with the three months ended September 30, 2011 as current year period increases in natural gas volume in the Appalachian Basin were offset by a decrease in our average realized natural gas price between the periods.

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Our net gathering and processing expense for the nine months ended September 30, 2012 was $2.9 million compared with $2.3 million for the nine months ended September 30, 2011. This increase was principally due to an increase in natural gas volume in the Appalachian Basin between the periods, partially offset by a decrease in our average realized natural gas price.

Other, net

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Other, net income was $0.1 million for the three months ended September 30, 2012 compared with expense of $0.1 million for the three months ended September 30, 2011.

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Other, net expenses were $5.0 million for the nine months ended September 30, 2012 compared with $0.1 million for the nine months ended September 30, 2011. The $4.9 million increase was primarily due to the premium amortization associated with derivative contracts for production volumes related to wells recently acquired from Carrizo (see Recent Developments).

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Total general and administrative expenses increased to $16.1 million for the three months ended September 30, 2012 compared with $4.8 million for the three months ended September 30, 2011. This increase was primarily due to a $4.8 million increase in non-cash compensation expense, a $4.0 million unfavorable movement related to a decrease in net reimbursements we received in association with our transition services agreement with Chevron, which expired during the first quarter of 2012, and a $2.3 million increase in non-recurring transaction costs related to our 2012 acquisition activity that included our consummated acquisitions of assets from Carrizo, Titan and Equal (see Recent Developments).

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Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Total general and administrative expenses increased to $48.4 million for the nine months ended September 30, 2012 compared with $12.3 million for the nine months ended September 30, 2011. This increase was primarily due to a $15.0 million unfavorable movement related to a decrease in net reimbursements we received in association with our transition services agreement with Chevron, which expired during the first quarter of 2012, a $13.5 million increase in non-recurring transaction costs related to our 2012 acquisition activity that included our consummated acquisitions of assets from Carrizo, Titan and Equal (see Recent Developments), and a $7.9 million increase in non-cash compensation expense.

Chevron Transaction Expense

During the three months ended September 30, 2012, we recognized a $7.7 million charge regarding our reconciliation process with Chevron related to certain amounts included within the contractual cash transaction adjustment, which was settled in October 2012 (see *Item 1: Financial Statements*).

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to $13.9 million for the three months ended September 30, 2012 compared with $8.1 million for the comparable prior year period primarily due to a $5.7 million increase in our depletion expense.

Total depreciation, depletion and amortization increased to $33.8 million for the nine months ended September 30, 2012 compared with $24.0 million for the comparable prior year period primarily due to a $9.1 million increase in our depletion expense.

The following table presents a summary of our depreciation, depletion and amortization expense and our depletion expense per Mcfe for our operations for the respective periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Depreciation, depletion and amortization:				
Depletion expense	$ 12,576	$ 6,882	$ 29,663	$ 20,626
Depreciation and amortization expense	1,342	1,189	4,185	3,393
	$ 13,918	$ 8,071	$ 33,848	$ 24,019
Depletion expense (in thousands):				
Total	$ 12,576	$ 6,882	$ 29,663	$ 20,626
Depletion expense as a percentage of gas and oil production revenue	51%	42%	48%	40%
Depletion per Mcfe	$ 1.42	$ 2.15	$ 1.64	$ 2.09

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties. For the three months ended September 30, 2012, depletion expense increased $5.7 million to $12.6 million compared with $6.9 million for the three months ended September 30, 2011. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 51% for the three months ended September 30, 2012, compared with 42% for the three months ended September 30, 2011, an increase which was primarily due to a decrease in realized natural gas prices and an increase in production volumes between periods. Depletion expense per Mcfe was $1.42 for the three months ended September 30, 2012, a decrease of $0.73 per Mcfe from $2.15 for the three months ended September 30, 2011, primarily related to lower depletion expense per Mcfe for the assets acquired from Carrizo and Titan (see Recent Developments) and the addition of reserves for new Marcellus Shale wells, which began production during the nine months ended September 30, 2012. Depletion expense increased between periods principally due to an overall increase in production volume.

For the nine months ended September 30, 2012, depletion expense was $29.7 million, an increase of $9.1 million in comparison with $20.6 million for the nine months ended September 30, 2011. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 48% for the nine months ended September 30, 2012, compared with 40% for the nine months ended September 30, 2011, an increase which was primarily due to a decrease in realized natural gas prices and an increase in production volumes between periods. Depletion expense per Mcfe was $1.64 for the nine months

ended September 30, 2012, a decrease of $0.45 per Mcfe from $2.09 for the nine months ended September 30, 2011, primarily related to lower depletion expense per Mcfe for the assets acquired from Carrizo and Titan (see Recent Developments) and the addition of reserves for new Marcellus Shale wells, which began production during the nine months ended September 30, 2012. Depletion expense increased between periods principally due to an overall increase in production volume.

Interest expense

Three Months Ended September 30, 2012 Compared with the Three Months Ended September 30, 2011. Interest expense for the three months ended September 30, 2012 was $1.4 million, which was associated with outstanding borrowings under our credit facility and amortization of deferred financing costs associated with the credit facility (see Credit Facility).

Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011. Interest expense for the nine months ended September 30, 2012 was $2.5 million, which was associated with outstanding borrowings under our credit facility and amortization of deferred financing costs associated with the credit facility (see Credit Facility).

Gain (Loss) on Asset Sales and Disposal

During the nine months ended September 30, 2012, we recognized a $7.0 million loss on asset sales and disposal, which pertained to management s decision to terminate a farm-out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm-out agreement contained certain well drilling milestones which needed to be met in order for us to maintain ownership of the South Knox processing plant. During 2012, management decided not to continue progressing towards these milestones due to the current natural gas price environment. As a result, we forfeited our interest in the processing plant and recorded a loss related to the net book value of the assets during the nine months ended September 30, 2012.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our investment partnerships, and borrowings under our credit facility (see Credit Facility). Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and quarterly distributions to our common limited partners 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 cash generated from operations, additional borrowings and capital raised through investment partnerships; and

- Debt principal payments through additional borrowings as they become due or by the issuance of additional common units or asset sales.

We rely on cash flow from operations and our credit facility to execute our growth strategy and to meet our financial commitments and other short-term liquidity needs. We cannot be certain that additional capital will be available to us to the extent required and on acceptable terms. We believe that we will have sufficient liquid assets, cash from operations and borrowing capacity to meet our financial commitments, debt service obligations, contingencies and anticipated capital expenditures for at least the next twelve month period. However, we are subject to business, operational and other risks that could adversely affect our cash flow. We may supplement our cash generation with proceeds from financing activities, including borrowings under our credit facility and other borrowings, the issuance of additional common units, the sale of assets and other transactions.

Cash Flows Nine Months Ended September 30, 2012 Compared with the Nine Months Ended September 30, 2011

Net cash used in operating activities of $15.0 million for the nine months ended September 30, 2012 represented an unfavorable movement of $56.5 million from net cash provided by operating activities of $41.5 million for the comparable prior year period. The $56.5 million unfavorable movement in net cash provided by operating activities resulted from a $92.3 million unfavorable movement in net income excluding non-cash items, partially offset by a $35.8 million favorable

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movement in working capital. The $92.3 million unfavorable movement in net income excluding non-cash items included a $60.5 million unfavorable movement in non-cash (gain) loss on derivative value and a $57.6 million decrease in net income, partially offset by a $9.8 million increase in depreciation, depletion and amortization expense, a $7.9 million increase in non-cash stock compensation, a $7.1 million increase in loss on asset disposal, and a $1.0 million increase in amortization of deferred financing costs relating to our credit facility assumed by us from ATLS. The $60.5 million unfavorable movement in non-cash (gain) loss on derivative value is primarily related to a $43.5 million non-cash loss on derivative value during the nine months ended September 30, 2011 resulting from the monetization of hedges prior to the acquisition of the Transferred Business from AEI and a $17.0 million non-cash gain on derivative value for the nine months ended September 30, 2012 related to a decline in natural gas prices during the period. The $35.8 million favorable movement in working capital was principally due to a $22.6 million favorable movement in accounts receivable and other current assets primarily due to a decrease in subscriptions receivable for funds raised during our Fall 2011 drilling program, as well as a $13.2 million favorable movement in accounts payable and other current liabilities primarily due to an increase in liabilities associated with well drilling and completion costs, partially offset by a decrease in liabilities associated with drilling contracts resulting from funds deployed related to our Fall 2011 drilling program during the nine months ended September 30, 2012.

Net cash used in investing activities of $337.9 million for the nine months ended September 30, 2012 represented an unfavorable movement of $301.6 million from net cash used in investing activities of $36.3 million for the comparable prior year period. This unfavorable movement was principally due to a $264.6 million unfavorable movement in net cash paid for acquisitions related to the Carrizo, Titan and Equal acquisitions as well as a $37.1 million unfavorable movement in capital expenditures, partially offset by a favorable movement of $0.1 million in other assets. See further discussion of capital expenditures under Management s Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Capital Requirements .

Net cash provided by financing activities of $322.4 million for the nine months ended September 30, 2012 represented a favorable movement of $267.7 million from net cash provided by financing activities of $54.7 million for the comparable prior year period. This movement was principally due to an increase of $264.0 million in borrowings under our credit facility and a $119.4 increase in net proceeds from issuance of common limited partner units, partially offset by an increase of $42.0 million in repayments under our credit facility, a net decrease of $49.1 million in the net investment from owners prior to March 5, 2012, an $8.2 million unfavorable movement in deferred financing costs and other resulting from the cash paid for credit facility financing costs and a $16.4 million increase in cash distributions paid to unitholders. The net decrease in the net investment from owners was due to an increase of $5.6 million for the investment received from ATLS in 2012, partially offset by a decrease of $54.7 million in the net investment received in from AEI in 2011. The gross amount of borrowings and repayments under our credit facility included within net cash provided by financing activities in the consolidated combined statements of cash flows, which are generally in excess of net borrowings or repayments during the period or at period end, reflect the timing of cash receipts, which generally occur at specific intervals during the period and are utilized to reduce borrowings under our credit facility, and payments, which generally occur throughout the period and increase borrowings under our credit facility, which is generally common practice for our industry.

Our July 2012 acquisition of Titan in exchange for 3.8 million common units and 3.8 million newly created convertible Class B preferred units (which had a collective value of $193.2 million, based upon the closing price of our publicly traded units as of the acquisition close date) represented a non-cash transaction during the nine months ended September 30, 2012 (see Recent Developments).

Capital Requirements

Our capital requirements consist primarily of:

- maintenance capital expenditures capital expenditures we make on an ongoing basis to maintain our current levels of production over the long term; and
- expansion capital expenditures capital expenditures we make to increase our current levels of production for longer than the short-term and includes new leasehold interests and the development and exploitation of existing leasehold interests through acquisitions and investments in our drilling partnerships.

The following table summarizes our 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,	
	2012	2011	2012	2011
Maintenance capital expenditures	$ 3,350	$ 2,300	$ 6,850	$ 7,533
Expansion capital expenditures	24,377	19,588	66,529	28,737
Total	$ 27,727	$ 21,888	$ 73,379	$ 36,270

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During the three months ended September 30, 2012, our $27.7 million of total capital expenditures consisted primarily of $20.7 million for well costs, which consist principally of our investments in the Drilling Partnerships, compared with $19.4 million for the prior year comparable period, $5.0 million of leasehold acquisition costs compared with $1.2 million for the prior year comparable period, $0.2 million of gathering and processing costs compared with $0.8 million for the prior year comparable period and $1.8 million of corporate and other compared with $0.5 million for the prior year comparable period. The increase in investments in the investment partnerships was the result of the cancellation of the Fall 2010 drilling program and the resulting reduction of partnership capital deployed during 2011. The net increase in leasehold acquisition costs principally related to additional Mississippi Lime acreage acquired during the three months ended September 30, 2012.

During the nine months ended September 30, 2012, our $73.4 million of total capital expenditures consisted primarily of $38.3 million for well costs compared with $26.5 million for the prior year comparable period, $27.6 million of leasehold acquisition costs compared with $2.6 million for the prior year comparable period, $1.3 million of gathering and processing costs compared with $3.2 million for the prior year comparable period and $6.2 million of corporate and other compared with $4.0 million for the prior year comparable period. The increase in well costs was principally the result of the cancellation of the Fall 2010 drilling program and the resulting reduction of partnership capital deployed during 2011. The net increase in leasehold acquisition costs principally related to additional Marcellus Shale and Utica Shale acreage acquisitions and Barnett Shale acreage acquired through subsequent leasehold acquisitions in the region during the nine months ended September 30, 2012.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisition, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of September 30, 2012, we are committed to expend approximately $20.4 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our investment partnerships and borrowings under our credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of September 30, 2012, our off-balance sheet arrangements were limited to our letters of credit outstanding of $0.6 million and commitments to spend $20.4 million related to our drilling and completion and capital expenditures.

CASH DISTRIBUTION POLICY

Our partnership agreement requires that we distribute 100% of available cash to our common unitholders and general partner within 45 days following the end of each calendar quarter in accordance with their respective percentage interests. Available cash consists generally of all of our cash receipts, less cash disbursements and net additions to reserves, including any reserves required under debt instruments for future principal and interest payments. Our general partner is granted discretion under the 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.

Available cash will initially be 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. The incentive distribution rights will entitle our general partner to receive the following increasing percentage of cash distributed by us as it reaches certain target distribution levels:

- 13.0% of all cash distributed in any quarter after each common unit has received $0.46 for that quarter;

- 23.0% of all cash distributed in any quarter after each common unit has received $0.50 for that quarter; and

- 48.0% of all cash distributed in any quarter after each common unit has received $0.60 for that quarter.

CREDIT FACILITY

At September 30, 2012, we had a senior secured credit facility with a syndicate of banks with a borrowing base of $310.0 million with $222.0 million outstanding. Concurrent with the closing of the Titan acquisition on July 25, 2012, we expanded the borrowing base on our revolving credit line from $250.0 million to $310.0 million. The credit facility matures in March 2016 and the borrowing base will be redetermined semi-annually in May and November. Up to $20.0 million of the credit facility may be in the form of standby letters of credit which would reduce our borrowing capacity, of which $0.6 million was outstanding at September 30, 2012, and was not reflected as borrowings on our consolidated combined balance sheet. Our obligations under the facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets, including all of our ownership interests in a majority of our material operating subsidiaries. Additionally, obligations under the facility are guaranteed by substantially all of our subsidiaries. Borrowings under the credit facility bear interest, at our election, at either LIBOR plus an applicable margin between 2.00% and 3.00% per annum or the base rate (which is the higher of the bank s prime rate, the Federal funds rate plus 0.5% or one-month LIBOR plus 1.00%) plus an applicable margin between 1.00% and 2.00% per annum. The applicable margin will fluctuate based on the utilization of the facility. Interest is generally payable quarterly for ABR loans and at the applicable maturity date for LIBOR loans. We are also required to pay a fee of 0.5% per annum on the unused portion of the borrowing base, which is included within interest expense on our consolidated combined statements of operations. At September 30, 2012, the weighted average interest rate was 2.7%.

The credit agreement contains customary covenants that limit our ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of our assets. We were in compliance with these covenants as of September 30, 2012. The credit agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the credit agreement) to four quarters (actual or annualized, as applicable) of EBITDA (as defined in the credit agreement) not greater than 3.75 to 1.0 as of the last day of any fiscal quarter, a ratio of current assets (as defined in the credit agreement) to current liabilities (as defined in the credit agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter, and a ratio of four quarters (actual or annualized, as applicable) of EBITDA to Consolidated Interest Expense (as defined in the credit agreement) of not less than 2.5 to 1.0 as of the last day of any fiscal quarter.

SECURED HEDGE FACILITY

At September 30, 2012, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships will have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our senior secured credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as general partner of the Drilling Partnerships, will administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership s ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

In addition, it will be an event of default under our credit facility if we, as general partner of the Drilling Partnerships, breach an obligation governed by the secured hedge facility and the effect of such breach is to cause amounts owing under swap agreements governed by the secured hedge facility to become immediately due and payable.

ISSUANCE OF UNITS

Titan Acquisition

On July 25, 2012, we completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million of our common units and 3.8 million of our newly-created convertible Class B preferred units (which had a collective value of $193.2 million, based upon the closing price of our publicly traded common units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Recent

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Developments). The preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike price of $26.03 plus all unpaid preferred distributions per unit, and will be mandatorily converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

We entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the Securities and Exchange Commission (SEC) by January 25, 2013 to register the resale of the common units issued on the acquisition closing date and those issuable upon conversion of the preferred units. We agreed to use our commercially reasonable efforts to have the registration statement declared effective by March 31, 2013, and to cause the registration statement to be continuously effective until the earlier of (i) the date as of which all such common units registered thereunder are sold by the holders and (ii) one year after the date of effectiveness. On September 19, 2012, we filed a registration statement with the SEC in satisfaction of the registration requirements of the registration rights agreement and the registration statement was declared effective by the SEC on October 2, 2012.

Carrizo Acquisition

On April 30, 2012, we completed the acquisition of certain oil and gas assets from Carrizo (see Recent Developments). To partially fund the acquisition, we sold 6.0 million of our common units in a private placement at a negotiated purchase price per unit of $20.00, for gross proceeds of $120.6 million, of which $5.0 million was purchased by certain of our executives. The common units issued by us are subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that we would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, we filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of one of the requirements of the registration rights agreement noted previously. On August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 limited partner units for each of ATLS common units owned on the record date of February 28, 2012. The distribution of these limited partner units represented approximately 20.0% of the common limited partner units outstanding (see Business Overview).

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires making estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of actual revenue and expenses during the reporting period. Although we base our estimates on historical experience and various other assumptions that we believe to be reasonable under the circumstances, actual results may differ from the estimates on which our financial statements are prepared at any given point of time. Changes in these estimates could materially affect our financial position, results of operations or cash flows. Significant items that are subject to such estimates and assumptions include revenue and expense accruals, depletion, 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 combined financial statements was included in our Annual Report on Form 10-K for the year ended December 31, 2011 and we summarize our significant accounting policies within our consolidated combined financial statements included in Note 2 under Item 1: Financial Statements included in this report. The critical accounting policies and estimates we have identified are discussed below.

Depreciation and Impairment of Long-Lived Assets and Goodwill

Long-Lived Assets. The cost of property, plant and equipment, less estimated salvage value, is generally depreciated on a straight-line basis over the estimated useful lives of the assets. Useful lives are based on historical experience and are adjusted when changes in planned use, technological advances or other factors indicate that a different life would be more appropriate. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively.

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Long-lived assets, other than goodwill and intangibles with infinite lives, generally consist of natural gas and oil properties and pipeline, processing and compression facilities and are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable. A long-lived asset, other than goodwill and intangibles with infinite lives, is considered to be impaired when the undiscounted net cash flows expected to be generated by the asset are less than its carrying amount. The undiscounted net cash flows expected to be generated by the asset are based upon our estimates that rely on various assumptions, including natural gas and oil prices, production and operating expenses. Any significant variance in these assumptions could materially affect the estimated net cash flows expected to be generated by the asset. As discussed in General Trends and Outlook within this section, recent increases in natural gas drilling has driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas prices may result in additional impairment charges in future periods.

There were no impairments of proved or unproved gas and oil properties recorded by us for the three and nine months ended September 30, 2012 and 2011. During the year ended December 31, 2011, we recognized a $7.0 million asset impairment related to gas and oil properties within property, plant and equipment on our consolidated combined balance sheet for shallow natural gas wells in the Niobrara Shale. This impairment related to the carrying amount of these gas and oil properties being in excess of our estimate of their fair value at December 31, 2011. The estimate of fair value of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

Events or changes in circumstances that would indicate the need for impairment testing include, among other factors: operating losses; unused capacity; market value declines; technological developments resulting in obsolescence; changes in demand for products manufactured by others utilizing our services or for our products; changes in competition and competitive practices; uncertainties associated with the United States and world economies; changes in the expected level of environmental capital, operating or remediation expenditures; and changes in governmental regulations or actions. Additional factors impacting the economic viability of long-lived assets are discussed under Item 1A: Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2011.

Goodwill and Intangibles with Infinite Lives. Goodwill and intangibles with infinite lives must be tested for impairment annually or more frequently if events or changes in circumstances indicate that the related asset might be impaired. An impairment loss should be recognized if the carrying value of an entity s reporting units exceeds its estimated fair value.

There were no goodwill impairments recognized by us during the three and nine months ended September 30, 2012 and 2011, respectively.

Fair Value of Financial Instruments

We have established a hierarchy to measure our financial instruments at fair value which requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

Level 2 Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 Unobservable inputs that reflect the entity s own assumptions about the assumptions market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

We use a fair value methodology to value the assets and liabilities for our outstanding derivative contracts. Our commodity hedges are calculated based on observable market data related to the change in price of the underlying commodity and are therefore defined as Level 2 fair value measurements.

Liabilities that are required to be measured at fair value on a nonrecurring basis include our asset retirement obligations (ARO s) that are defined as Level 3. Estimates of the fair value of ARO s are based on discounted cash flows using numerous estimates, assumptions, and judgments regarding the cost, timing of settlement, our credit-adjusted risk-free rate and inflation rates.

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Reserve Estimates

Our estimates of proved natural gas and oil reserves and future net revenues from them are based upon reserve analyses that rely upon various assumptions, including those required by the SEC, as to natural gas and oil prices, drilling and operating expenses, capital expenditures and availability of funds. The accuracy of these reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions, and the judgments of the individuals preparing the estimates. As discussed in Item 2: Properties of our Annual Report on Form 10-K for the year ended December 31, 2011, we engaged Wright and Company, Inc., an independent third-party reserve engineer, to prepare a report of our proved reserves.

Any significant variance in the assumptions utilized in the calculation of our reserve estimates could materially affect the estimated quantity of our reserves. As a result, our estimates of proved natural gas and oil reserves are inherently imprecise. Actual future production, natural gas and oil prices, revenues, development expenditures, operating expenses and quantities of recoverable natural gas and oil reserves may vary substantially from our estimates or estimates contained in the reserve reports and may affect our ability to pay amounts due under our credit facility or cause a reduction in our credit facility. In addition, our proved reserves may be subject to downward or upward revision based upon production history, results of future exploration and development, prevailing natural gas and oil prices, mechanical difficulties, governmental regulation and other factors, many of which are beyond our control. Our reserves and their relation to estimated future net cash flows impact the calculation of impairment and depletion of oil and gas properties. Adjustments to quarterly depletion rates, which are based upon a units of production method, are made concurrently with changes to reserve estimates. Generally, an increase or decrease in reserves without a corresponding change in capitalized costs will have a corresponding inverse impact to depletion expense.

Asset Retirement Obligations

On an annual basis, we estimate the cost of future dismantlement, restoration, reclamation and abandonment of our operating assets. We also estimate the salvage value of equipment recoverable upon abandonment. For the three and nine months ended September 30, 2012 and 2011, the estimate of salvage values was greater than or equal to our estimate of the costs of future dismantlement, restoration, reclamation and abandonment. Projecting future retirement cost estimates is difficult as it involves the estimation of many variables such as economic recoveries of reserves, future labor and equipment rates, future inflation rates and our subsidiaries credit adjusted risk free rate. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Since there are many variables in estimating asset retirement obligations, we attempt to limit the impact of management s judgment on certain of these variables by developing a standard cost estimate based on historical costs and industry quotes updated annually. To the extent future revisions to these assumptions impact the fair value of our existing asset retirement obligation, a corresponding adjustment is made to our gas and oil properties and other property, plant and equipment. A decrease in salvage values or an increase in dismantlement, restoration, reclamation and abandonment costs from those we and our subsidiaries have estimated, or changes in their estimates or costs, could reduce our gross profit from operations.

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 commodity prices. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonable possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of the market risk sensitive instruments were entered into for purposes other than trading.

General

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

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 financial instruments such as forward contracts and swap agreements. 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, 2012. Only the potential impact of hypothetical assumptions was 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 related to our commodity derivative contracts are banking institutions or their affiliates, who also participate in our revolving credit facilities. The creditworthiness of our counterparties is constantly monitored, and we currently believe them to be financially viable. We are not aware of any inability on the part of our counterparties to perform under their contracts and believe our exposure to non-performance is remote.

Interest Rate Risk. At September 30, 2012, we had $222.0 million of borrowings under our revolving credit facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would have a $2.2 million impact on our consolidated combined interest expense for the twelve month period ending September 30, 2013.

Commodity Price Risk. Our market risk exposure to commodities is due to the fluctuations in the commodity prices and the impact those price movements have on our financial results. To limit our exposure to changing commodity prices, we use financial derivative instruments, including financial swap and option instruments, to hedge portions of our future production. The swap instruments are contractual agreements between counterparties to exchange obligations of money as the underlying commodities are sold. Under these swap agreements, we receive or pay a fixed price and receive or remit a floating price based on certain indices for the relevant contract period. Option instruments are contractual agreements that grant the right, but not the obligation, to purchase or sell commodities at a fixed price for the relevant period.

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in the average commodity prices would result in a change to our consolidated combined operating income for the twelve-month period ending September 30, 2013 of approximately $6.5 million.

At September 30, 2012, we had the following commodity derivatives:

Natural Gas Fixed Price Swaps

Production Period Ending December 31,	Volumes (mmbtu)(1)	Average Fixed Price (per mmbtu)(1)
2012	5,591,000	$ 3.378
2013	21,529,700	$ 3.853
2014	16,233,000	$ 4.215
2015	11,994,500	$ 4.259
2016	9,866,300	$ 4.334
2017	3,600,000	$ 4.579

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (mmbtu)(1)	Average Floor and Cap (per mmbtu)(1)
2012	Puts purchased	1,080,000	$ 4.074
2012	Calls sold	1,080,000	$ 5.279
2013	Puts purchased	5,520,000	$ 4.395
2013	Calls sold	5,520,000	$ 5.443
2014	Puts purchased	3,840,000	$ 4.221
2014	Calls sold	3,840,000	$ 5.120
2015	Puts purchased	3,480,000	$ 4.234
2015	Calls sold	3,480,000	$ 5.129

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Natural Gas Put Options

Production Period Ending December 31,	Option Type	Volumes (mmbtu)[1]	Average Fixed Price (per mmbtu)[1]
2012	Puts purchased	1,470,000	$ 2.802
2013	Puts purchased	3,180,000	$ 3.450
2014	Puts purchased	1,800,000	$ 3.800
2015	Puts purchased	1,440,000	$ 4.000
2016	Puts purchased	1,440,000	$ 4.150

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]
2012	6,750	$ 103.804
2013	18,600	$ 100.669
2014	36,000	$ 97.693
2015	45,000	$ 89.504

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]
2012	Puts purchased	15,000	$ 90.000
2012	Calls sold	15,000	$ 117.912
2013	Puts purchased	60,000	$ 90.000
2013	Calls sold	60,000	$ 116.396
2014	Puts purchased	41,160	$ 84.169
2014	Calls sold	41,160	$ 113.308
2015	Puts purchased	29,250	$ 83.846
2015	Calls sold	29,250	$ 110.654

(1) Mmbtu represents million British Thermal Units; Bbl represents barrels.

ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Securities Exchange Act of 1934 reports is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms, and that such information is accumulated and communicated to our management, including our general partner s Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. In designing and evaluating the disclosure controls and procedures, our management recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and our management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

Under the supervision of our general partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our general partner s Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2012, our disclosure controls and procedures were effective at the reasonable assurance level.

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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.

In April and July 2012, we acquired certain assets from Carrizo and Titan, respectively (see Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments). We are continuing to integrate these systems historical internal controls over financial reporting with our existing internal controls over financial reporting. This integration may lead to changes in our or the acquired systems historical internal controls over financial reporting in future fiscal reporting periods.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

One of our subsidiaries entered into two agreements with the United States Environmental Protection Agency (the EPA), effective on September 25, 2012, to settle alleged violations in connection with a fire that occurred at a natural gas well and associated well pad site in Washington County, Pennsylvania in 2010. The EPA alleged non-compliance with the Clean Air Act, including with respect to the storage and handling of the natural gas condensate as well as non-compliance with the Emergency Planning and Community Right-to-Know Act of 1986. Our subsidiary agreed to a civil penalty of $84,506 under a consent agreement and agreed to upgrade its facility pursuant to an administrative settlement agreement.

On August 3, 2011, CNX Gas Company LLC filed a lawsuit in the United States District Court for the Eastern District of Tennessee at Knoxville styled *CNX Gas Company LLC vs. Miller Energy Resources, Inc., Chevron Appalachia, LLC as successor in interest to Atlas America, LLC, Cresta Capital Strategies, LLC, and Scott Boruff*, No. 3:11-cv-00362. On April 16, 2012 Atlas Energy Tennessee, LLC, an indirect wholly-owned subsidiary, was brought in to the lawsuit by way of Amended Complaint. On April 23, 2012, the Court dismissed Chevron Appalachia, LLC as a party on the grounds of lack of subject matter jurisdiction over that entity.

The lawsuit alleges that CNX entered into a Letter of Intent with Miller Energy for the purchase by CNX of certain leasehold interests containing oil and natural gas rights, representing around 30,000 acres in East Tennessee. The lawsuit also alleges that Miller Energy breached the Letter of Intent by refusing to close by the date provided and by allegedly entertaining offers from third parties for the same leasehold interests. Allegations of inducement of breach of contract and related claims are made by CNX against the remaining defendants, on the theory that these parties knew of the terms of the Letter of Intent and induced Miller Energy to breach the Letter of Intent. CNX is seeking $15.5 million in damages. We assert that we acted in good faith and believe that the outcome of the litigation will be resolved in our favor.

We are also a party to various routine legal proceedings arising out of the ordinary course of our business. Management believes that none of these actions, individually or in the aggregate, will have a material adverse effect on our financial condition or results of operations.

ITEM 1A: RISK FACTORS

Regulations promulgated by the Commodities Futures Trading Commission could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act is intended to change fundamentally the way swap transactions are entered into, transforming an over-the-counter market in which parties negotiate directly with each other into a regulated market in which most swaps are to be executed on registered exchanges or swap execution facilities and cleared through central counterparties. These statutory requirements must be implemented through regulation, primarily through rules to be adopted by the Commodities Futures Trading Commission, or CFTC. Many market participants will be newly regulated as swap dealers or major swap participants, with new regulatory capital requirements and other regulations that impose business conduct rules and mandate how they hold collateral or margin for swap transactions. All market participants will be subject to new reporting and recordkeeping requirements. The new regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our existing or future derivative activities. As a commercial end-user which uses swaps to hedge or mitigate commercial risk, rather than for speculative purposes, we are permitted to opt out of the clearing and exchange trading requirements. However, we could be exposed to greater liquidity and credit risk with respect to our hedging transactions if we do not use cleared and exchange-traded swaps. Counterparties to our derivative instruments which are federally insured depository institutions are required to spin off some of their derivatives activities to separate entities, which may not be as creditworthy as the current counterparties. The new regulations could significantly increase the cost of derivative contracts; materially alter the terms of derivative contracts; reduce the availability of derivatives to protect against risks we encounter; reduce our ability to monetize or restructure our derivative contracts in existence at that time; and increase our exposure to less creditworthy counterparties. If we reduce or change the way we use derivative instruments as a result of the legislation or regulations, our results of operations may become more volatile and cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on our combined financial position, results of operations and/or cash flows.

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Federal legislation and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions or by state environmental agencies.

Some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. For example:

New York has imposed a *de facto* moratorium on the issuance of permits for high volume, horizontal hydraulic fracturing until state administered environmental studies are finalized. The public comment period for proposed regulations closed in January 2012. Final Regulations have not yet been issued. In October 2012, the New York Department of Environmental Conservation asked the New York Health Department to assess the health impacts of high volume hydraulic fracturing. If regulations are not issued by November 29, 2012, that is, one year from the last public hearing, and/or an extension is not granted, then the rulemaking process must be reopened.

Pennsylvania has adopted a variety of regulations limiting how and where fracturing can be performed. In February 2012, legislation was passed in Pennsylvania requiring, among other things, disclosure of chemicals used in hydraulic fracturing. To implement the new legislative requirements, in August of 2012 the Pennsylvania Department of Environmental Protection issued proposed conceptual changes to its environmental regulations governing oil and gas operations. The conceptual changes would include requiring secondary containment for tanks associated with hydraulic fracturing and the submission of increased water withdrawal information necessary to secure required Water Management Plans.

In June 2012, Ohio passed legislation that made several significant amendments to the state s oil and gas law, including additional permitting requirements, chemical disclosure requirements, and site investigation requirements for horizontal wells.

In September 2012, the Texas Railroad Commission approved new proposed regulations relating to the commercial recycling of produced water and/or hydraulic fracturing flowback fluid.

In June 2012, the West Virginia Department of Environmental Protection introduced a proposed legislative rule titled Rules Governing Horizontal Well Development, which imposes more stringent regulation of horizontal drilling. The proposed rule was developed to provide further direction in the implementation and administration of the Natural Gas Horizontal Well Control Act that became effective on December 14, 2011.

In addition to state law, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. If state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. Generally, Federal, state and local restrictions and requirements are applied consistently to similar types of producers (e.g., conventional, unconventional, etc.), regardless of size of the producing company.

Although, to date, the hydraulic fracturing process has not generally been subject to regulation at the federal level, there are certain governmental reviews either under way or being proposed that focus on environmental aspects of hydraulic fracturing practices, and some federal regulation has taken place. A few of these initiatives are listed here, although others may exist now or be implemented in the future. In April 2012, President Obama established an Interagency Working Group to Support Safe and Responsible Development of Unconventional Domestic Natural Gas Resources with the purpose of coordinating the policies and activities of agencies regarding unconventional gas development. The Environmental Protection Agency, which we refer to as the EPA, has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel as an additive under the Safe Drinking Water Act. In May 2012, the EPA issued draft

permitting guidance for oil and gas hydraulic fracturing activities using diesel fuel. After reviewing comments submitted on the draft guidance in September 2012, the EPA is considering withdrawing the draft guidance and reissuing the policies contained therein as a proposed rulemaking. In addition, legislation that would provide for increased federal regulation of hydraulic fracturing and require disclosure of the chemicals used in the hydraulic fracturing process could be introduced in the future. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. For example, the EPA is currently studying the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a progress report expected to be available by late 2012 and final draft report for public comment and peer review expected to be available by 2014. The EPA is also proposing to issue a draft criteria document updating the water quality criteria for chloride in early 2013, and a proposed rule regarding effluent limitation guidelines for natural gas extraction from shale gas in 2014. On May 4, 2012, the U.S. Department of the Interior, Bureau of Land Management proposed a rule that includes provisions requiring disclosure of chemicals used in hydraulic fracturing and construction standards for hydraulic fracturing on federal lands.

Certain members of U.S. Congress have called upon the U.S. Government Accountability Office to investigate how hydraulic fracturing might adversely affect water resources, and Congress has asked the SEC to investigate the natural gas industry and any possible misleading of investors or the public regarding the economic feasibility of pursuing natural gas deposits in shales by means of hydraulic fracturing. In addition, Congress requested the U.S. Energy Information Administration to provide a better understanding of that agency s estimates regarding natural gas reserves, including reserves from shale formations, as well as uncertainties associated with those estimates. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could result in initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or one or more other regulatory mechanisms. If new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform hydraulic fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could be significantly affected. Some of the potential effects of changes in Federal, state or local regulation of hydraulic fracturing operations could include, but are not limited to, the following: additional permitting requirements, permitting delays, increased costs, changes in the way operations, drilling and/or completion must be conducted, increased recordkeeping and reporting, and restrictions on the types of additives that can be used, among other potential effects that are not listed here. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Recently promulgated rules regulating air emissions from oil and natural gas operations could cause us to incur increased capital expenditures and operating costs.

In August 2012, the EPA published final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA s rule package includes New Source Performance Standards, which we refer to as the NSPS, to address emissions of sulfur dioxide and volatile organic compounds, which we refer to as VOCs, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The NSPS require operators, starting in 2015, to reduce VOC emissions from oil and natural gas production facilities by conducting green completions for hydraulic fracturing, that is, recovering rather than venting the gas and natural gas liquids that come to the surface during completion of the fracturing process. The NSPS also establish specific requirements regarding emissions from compressors, dehydrators, storage tanks, and other production equipment. In addition, effective in 2012, the rules establish new notification requirements before conducting hydraulic fracturing and more stringent leak detection requirements for natural gas processing plants. The NSPS became effective October 15, 2012 and will likely require a number of modifications to our operations, including the installation of new equipment. Compliance with the new rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

States are also proposing more stringent requirements in air permits for well sites and compressor stations. For example, Pennsylvania has proposed to revise a list of sources exempt from air permitting requirements such that certain sources associated with oil and gas exploration and production would be required to obtain an air permit. In conjunction with this proposal, Pennsylvania has proposed to revise its General Permit for Natural Gas Production Facilities to include well sites. Ohio is also considering revising its current General Permit for Natural Gas Production Operations to cover emissions from completion activities.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for our services.

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Both houses of U.S. Congress have actively considered legislation to reduce emissions of greenhouse gases, and almost half of the states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of allowances available for purchase reduced each year until the overall greenhouse gas emission reduction goal is achieved. The adoption of any legislation or regulations that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce.

In response to findings that emissions of carbon dioxide, methane, and other greenhouse gases present a danger to public health and the environment because emissions of such gases are contributing to the warming of the earth s atmosphere and other climate changes, the EPA has adopted regulations under existing provisions of the Clean Air Act that require entities that produce certain gases to inventory, monitor and report such gases. On November 30, 2010, the EPA published a final greenhouse gas emissions reporting rule relating to natural gas processing, transmission, storage, and distribution activities, which required reporting by September 28, 2012 for emissions occurring in 2011. Additionally, in 2010, the EPA issued rules to regulate greenhouse gas emissions through traditional major source construction and operating permit programs. The EPA confirmed the permitting thresholds established in the 2010 rule in July 2012. These permitting programs require consideration of and, if deemed necessary, implementation of best available control technology to reduce greenhouse gas emissions. As a result, our operations could face additional costs for emissions control and higher costs of doing business.

Our drilling and production operations require adequate sources of water to facilitate the fracturing process and the disposal of that water. If we are unable to dispose of the water we use or remove from the strata at a reasonable cost and within applicable environmental rules, our ability to produce gas commercially and in commercial quantities could be impaired.

A significant portion of our natural gas extraction activity utilizes hydraulic fracturing, which results in water that must be treated and disposed of in accordance with applicable regulatory requirements. Environmental regulations governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing may increase operating costs and cause delays, interruptions or termination of operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial performance. For example, Pennsylvania requires the development of a Water Management Plan before hydraulically fracturing an unconventional well. The requirements of these plans continue to be modified by state laws and Pennsylvania Department of Environmental Protection, which we refer to as the PADEP, policies. In June 2012, Ohio passed legislation that established a water withdrawal and consumptive use permit program in the Lake Erie watershed. If certain withdrawal thresholds are triggered due to our water needs for a particular project, we will be required to develop a Water Conservation Plan and obtain a withdrawal permit for that project.

Our ability to collect and dispose of water will affect our production, and potential increases in the cost of water treatment and disposal may affect our profitability. The imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct hydraulic fracturing or disposal of produced water, drilling fluids and other substances associated with the exploration, development and production of gas and oil. For example, in July 2012, the Ohio Department of Natural Resources promulgated emergency amendments to the regulations governing disposal wells in Ohio. The emergency rules provide the Department with the authority to require certain testing as part of the process for obtaining a permit for the underground injection of produced water, and require all new disposal wells to be equipped with continuous pressure monitors and automatic shut off devices.

Impact fees and severance taxes could materially increase our liabilities.

In an effort to offset budget deficits and fund state programs, many states have imposed impact fees and/or severance taxes on the natural gas industry. In February 2012, Pennsylvania implemented an impact fee for unconventional wells drilled in the counties that elect to impose the fee. An unconventional gas well is a well that is drilled into an unconventional formation, which is defined as a geologic shale formation below the base of the Elk Sandstone or its geologic equivalent where natural gas generally cannot be produced except by horizontal or vertical well bores stimulated by hydraulic fracturing, which would include the Marcellus Shale. The fee, which changes from year to year, is based on the average annual price of natural gas as determined by the NYMEX price, as reported by the Wall Street Journal for the last trading day of each calendar month. For example, based upon natural gas prices for 2011, the impact fee for qualifying unconventional horizontal wells spudded by the end of 2011 was $50,000 per well, while the impact fee for unconventional vertical wells was reduced to twenty percent of the horizontal well fee. The payment structure for the impact fee makes the fee due the year after an unconventional well is spudded, and the fee will continue for 15 years for a horizontal well and 10 years for a vertical well.

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The impact fee for our wells including the wells in our Drilling Partnerships was approximately $2.8 million for the year ended December 31, 2011. In total, the natural gas industry paid more than $200 million to the Commonwealth of Pennsylvania, which will be distributed between state agencies, local entities and other related groups.

Ohio Governor John Kasich has proposed a severance tax on shale gas, shale oil, and natural gas liquids recovered through hydraulic fracturing. Under the proposed tax plan, oil and natural gas liquids recovered through hydraulic fracturing in the Utica and Marcellus shales would be taxed at 1.5% of annual gross sales in the first year and 4% afterward. Dry gas would be taxed yearly at 1% of gross sales, rather than the $0.03/Mcf the state currently charges. The proposed plan also levies a $25,000 fee on each well drilled.

President Obama s Fiscal Year 2013 Budget Proposal also includes provisions with significant tax consequences. If enacted, U.S. tax laws would be amended to eliminate the immediate deduction for intangible drilling and development costs and to eliminate the deduction from income for domestic production activities relating to oil and natural-gas exploration and development.

Because we handle natural gas and oil, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of substances into the environment.

How we plan, design, drill, install, operate and abandon natural gas wells and associated facilities are matters subject to stringent and complex federal, state and local environmental laws and regulations. These include, for example:

- The federal Clean Air Act and comparable state laws and regulations that impose obligations related to air emissions;

- The federal Clean Water Act and comparable state laws and regulations that impose obligations related to spills, releases, streams, wetlands and discharges of pollutants into regulated bodies of water;

- The federal Resource Conservation and Recovery Act, which we refer to as RCRA, and comparable state laws that impose requirements for the handling and disposal of waste, including produced waters, from our facilities;

- The federal Comprehensive Environmental Response, Compensation, and Liability Act, which we refer to as CERCLA, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us and AEI or at locations to which we and AEI have sent waste for disposal; and

- Wildlife protection laws and regulations such as the Migratory Bird Treaty Act that requires operators to cover reserve pits during the cleanup phase of the pit, if the pit is open more than 90 days.

Complying with these requirements is expected to increase costs and prompt delays in natural gas production. There can be no assurance that we will be able to obtain all necessary permits and, if obtained, that the costs associated with obtaining such permits will not exceed those that previously had been estimated. It is possible that the costs and delays associated with compliance with such requirements could cause us to delay or abandon the further development of certain properties.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. These enforcement actions may be handled by the EPA and/or the appropriate state agency. In some cases, the EPA has taken a heightened role in oil and gas enforcement activities. For example, in 2011, EPA Region III requested the lead on all oil and gas related violations in the United States Army Corps of Engineers Pittsburgh District. We also understand that the EPA has taken an increased interest in assessing operator compliance with the Spill Prevention, Control and Countermeasures regulations, set forth at 40 CFR Part 112.

Certain environmental statutes, including RCRA, CERCLA, the federal Oil Pollution Act and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where certain substances have been disposed of or otherwise released, whether caused by our operations, the past operations of our predecessors or third parties. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

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There is an inherent risk that we and our subsidiaries may incur environmental costs and liabilities due to the nature of our and our subsidiaries businesses and the substances we and our subsidiaries handle. For example, an accidental release from one of our or our subsidiaries wells could subject us, or the applicable subsidiary, to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines or penalties for related violations of environmental laws or regulations. Moreover, the possibility exists that stricter laws, regulations or enforcement policies may be enacted or adopted and could significantly increase our and our subsidiaries compliance costs and the cost of any remediation that may become necessary. We or the applicable subsidiary may not be able to recover remediation costs under our respective insurance policies.

We are subject to comprehensive federal, state, local and other laws and regulations that could increase the cost and alter the manner or feasibility of us doing business.

Our operations are regulated extensively at the federal, state and local levels. The regulatory environment in which we operate includes, in some cases, legal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing drilling and production activities. In addition, our activities will be subject to the regulations regarding conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could inhibit our ability to develop our respective properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase the financial and managerial costs of compliance with these laws and regulations and, consequently, reduce our profitability. For example, Pennsylvania s General Assembly approved legislation in February 2012 that imposes significant, costly requirements on the natural gas industry, including the imposition of increased bonding requirements and impact fees for gas wells, based on the price of natural gas and the age of the well. Regulations associated with this legislation are being conceptually discussed by the PADEP and, if finalized, will impact how natural gas operations are conducted in Pennsylvania. Similarly, West Virginia has proposed regulations associated with its existing Horizontal Well Control Act and is signaling that additional regulations are on the horizon. We may be put at a competitive disadvantage to larger companies in our industry that can spread these additional costs over a greater number of wells and these increased regulatory hurdles over a larger operating staff.

ITEM 6. EXHIBITS

Exhibit No.	Description
2.1	Separation and Distribution Agreement, dated February 23, 2012, by and among Atlas Energy, L.P., Atlas Energy GP, LLC, Atlas Resource Partners, L.P. and Atlas Resource Partners GP, LLC. The schedules to the Separation and Distribution Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.(1)
2.2	Purchase and Sale Agreement, dated as of March 15, 2012, among ARP Barnett, LLC, Carrizo Oil & Gas, Inc., CLLR, Inc., Hondo Pipeline, Inc. and Mescalero Pipeline, Inc. The schedules to the Purchase and Sale Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted schedules will be furnished to the U.S. Securities and Exchange Commission supplementally upon request.(11)
2.3	Merger Agreement dated as of May 17, 2012 among Atlas Resource Partners, L.P., Titan Merger Sub, LLC and Titan Operating, L.L.C. The annexes, schedules and exhibits to the Merger Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted annexes, schedules and exhibits will be furnished to the U.S. Securities and Exchange Commission upon request.(12)
3.1	Certificate of Limited Partnership of Atlas Resource Partners, L.P.(2)
3.2(a)	Amended and Restated Limited Partnership Agreement of Atlas Resource Partners, L.P.(4)

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3.2(b)	Amendment No. 1 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of July 25, 2012(13)
3.3	Certificate of Formation of Atlas Resource Partners GP, LLC.(2)
3.4	Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC.(8)
10.1	Pennsylvania Operating Services Agreement dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.), Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, L.P.) and Atlas Resources, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.2	Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.3	Amendment No. 1 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of January 6, 2011.(5)
10.4	Amendment No. 2 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of February 2, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.5	Transaction Confirmation, Supply Contract No. 0001, under Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated February 17, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.6	Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)
10.7	Gas Gathering Agreement for Natural Gas on the Expansion Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission.(5)

10.8	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010.[6]
10.9	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010.[6]
10.10(a)	Credit Agreement, dated as of March 5, 2012, among Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders[3]
10.10(b)	First Amendment to Credit Agreement, dated as of April 30, 2012, between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders[9]
10.10(c)	Joinder Agreement dated April 18, 2012 between ARP Barnett, LLC, ARP Oklahoma, LLC and Wells Fargo Bank, N.A.[9]
10.10(d)	Joinder Agreement dated April 30, 2012 between ARP Barnett Pipeline, LLC and Wells Fargo Bank, N.A.[9]
10.10(e)	Second Amendment to Amended and Restated Credit Agreement dated as of July 26, 2012, between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders[13]
10.10(f)	Joinder Agreement dated as of July 26, 2012, between Atlas Barnett, LLC and Wells Fargo Bank, N.A.[13]
10.11	Secured Hedge Facility Agreement, dated as of March 5, 2012, among Atlas Resources, LLC, the participating partnerships from time to time party thereto, the hedge providers from time to time party thereto and Wells Fargo Bank, N.A., as collateral agent for the hedge providers[3]
10.12	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P.[4]
10.13	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan[10]
10.14	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan[10]
10.15	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan[10]
10.16	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011[5]
10.17	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011[5]
10.18	Employment Agreement between Atlas Energy, L.P. and Matthew A. Jones dated as of November 4, 2011[7]
10.19	Common Unit Purchase Agreement, dated as of March 15, 2012, among Atlas Resource Partners, L.P. and the various purchasers party thereto[11]
10.20	Registration Rights Agreement, dated as of April 30, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein[9]
10.21	Registration Rights Agreement, dated as of July 25, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein[13]

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10.22	Registration Rights Agreement, dated as of May 16, 2012, between Atlas Resource Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Credit Agreement dated May 16, 2012 by and among Atlas Energy, L.P. and the lenders named therein.(14)
31.1	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2	Rule 13(a)-14(a)/15(d)-14(a) Certification
32.1	Section 1350 Certification
32.2	Section 1350 Certification
101.INS	XBRL Instance Document(15)
101.SCH	XBRL Schema Document(15)
101.CAL	XBRL Calculation Linkbase Document(15)
101.LAB	XBRL Label Linkbase Document(15)
101.PRE	XBRL Presentation Linkbase Document(15)
101.DEF	XBRL Definition Linkbase Document(15)

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on February 24, 2012.
(2) Previously filed as an exhibit to our Registration Statement on Form 10, as amended (File No. 1-35317).
(3) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 7, 2012.
(4) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 14, 2012.
(5) Previously filed as an exhibit to Atlas Energy s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011.
(6) Previously filed as an exhibit to Atlas Energy s Current Report on Form 8-K filed on November 12, 2010.
(7) Previously filed as an exhibit to Atlas Energy s Annual Report on Form 10-K for the year ended December 31, 2011.
(8) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.
(9) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 1, 2012.
(10) Previously filed as an exhibit to our Annual Report on Form 10-K for the year ended December 31, 2011.
(11) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 21, 2012.
(12) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 21, 2012.
(13) Previously filed as an exhibit to our Current Report on Form 8-K filed on July 26, 2012.
(14) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.
(15) 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 RESOURCE PARTNERS, L.P. **By: Atlas Resource Partners GP, LLC, its general partner**
Date: November 6, 2012	By: /s/ EDWARD E. COHEN Edward E. Cohen Chairman of the Board and Chief Executive Officer of the General Partner
Date: November 6, 2012	By: /s/ SEAN P. MCGRATH Sean P. McGrath Chief Financial Officer of the General Partner
Date: November 6, 2012	By: /s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback Chief Accounting Officer of the General Partner