Atlas Resource Partners, L.P.
Form 10-Q
August 09, 2012
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2012

OR

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

For the transition period from to

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	**45-3591625**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
Park Place Corporate Center One 1000 Commerce Drive, Suite 400 Pittsburgh, Pennsylvania	**15275**
(Address of principal executive office)	**(Zip code)**

Registrant s telephone number, including area code: (800) 251-0171

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

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

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

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

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

The number of outstanding common limited partner units of the registrant on August 1, 2012 was 36,069,778.

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ATLAS RESOURCE PARTNERS, L.P.

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ON FORM 10-Q

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PART 1. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED COMBINED BALANCE SHEETS

(in thousands)

(Unaudited)

	June 30, 2012	December 31, 2011
ASSETS		
Current assets:		
Cash and cash equivalents	$ 25,143	$ 54,708
Accounts receivable	22,067	19,319
Current portion of derivative asset	16,127	13,801
Subscriptions receivable		34,455
Prepaid expenses and other	7,173	7,677
Total current assets	70,510	129,960
Property, plant and equipment, net	752,505	520,883
Goodwill and intangible assets, net	33,193	33,285
Long-term derivative asset	19,554	16,128
Other assets, net	8,090	857
	$ 883,852	$ 701,113
LIABILITIES AND PARTNERS CAPITAL/EQUITY		
Current liabilities:		
Accounts payable	$ 26,006	$ 36,731
Liabilities associated with drilling contracts	18,757	71,719
Current portion of derivative payable to Drilling Partnerships	15,880	20,900
Accrued well drilling and completion costs	34,936	17,585
Accrued liabilities	21,209	35,952
Total current liabilities	116,788	182,887
Long-term debt	144,000	
Long-term derivative liability	128	
Long-term derivative payable to Drilling Partnerships	8,508	15,272
Asset retirement obligations and other	51,046	45,779
Commitments and contingencies		
Partners Capital/Equity:		
General partner s interest	8,135	
Common limited partners interest	521,002	
Equity		427,246
Accumulated other comprehensive income	34,245	29,929
Total partners capital/equity	563,382	457,175

	$ 883,852	$ 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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Revenues:				
Gas and oil production	$ 19,460	$ 17,723	$ 36,624	$ 35,349
Well construction and completion	12,241	10,954	55,960	28,679
Gathering and processing	2,863	5,118	6,177	9,617
Administration and oversight	1,315	1,375	4,146	2,736
Well services	5,252	4,855	10,258	10,141
Other, net	(4,086)	(12)	(5,019)	(65)
Total revenues	37,045	40,013	108,146	86,457
Costs and expenses:				
Gas and oil production	4,447	4,042	8,952	7,963
Well construction and completion	10,606	9,284	48,301	24,305
Gathering and processing	3,953	5,763	8,627	11,497
Well services	2,414	1,674	4,844	4,034
General and administrative	20,538	3,276	32,280	7,518
Depreciation, depletion and amortization	10,822	8,247	19,930	15,948
Total costs and expenses	52,780	32,286	122,934	71,265
Operating income (loss)	(15,735)	7,727	(14,788)	15,192
Interest expense	(956)		(1,106)	
Gain (loss) on asset sales and disposal	(16)	48	(7,021)	48
Net income (loss)	$ (16,707)	$ 7,775	$ (22,915)	$ 15,240
Allocation of net income (loss):				
Portion applicable to owners interest (period prior to the transfer of assets on March 5, 2012)	$	$ 7,775	$ 250	$ 15,240
Portion applicable to common limited partners and the general partner s interests (period subsequent to the transfer of assets on March 5, 2012)	(16,707)		(23,165)	
Net income (loss)	$ (16,707)	$ 7,775	$ (22,915)	$ 15,240
Allocation of net loss attributable to common limited partners and the general partner:				
Common limited partners interest	$ (16,373)	$	$ (22,702)	$
General partner s interest	(334)		(463)	
Net loss attributable to common limited partners and the general partner	$ (16,707)	$	$ (23,165)	$
Net loss attributable to common limited partners per unit:				

Basic	$	(0.54)	$	$	(0.77)	$
Diluted	$	(0.54)	$	$	(0.77)	$
Weighted average common limited partner units outstanding:						
Basic		30,307			29,367	
Diluted		30,307			29,367	

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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Net income (loss)	$ (16,707)	$ 7,775	$ (22,915)	$ 15,240
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	(514)	6,407	13,655	6,849
Less: reclassification adjustment for realized gains in net income (loss)	(6,739)	(1,578)	(9,339)	(9,309)
Total other comprehensive income (loss)	(7,253)	4,829	4,316	(2,460)
Comprehensive income (loss) attributable to common limited partners and the general partner	$ (23,960)	$ 12,604	$ (18,599)	$ 12,780

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 Capital		Common Limited Partners Capital			Accumulated Other Comprehensive Income	Total Partners Capital/ Equity
	Class A Units	Amount	Units	Amount	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	123,021		6,027,945	119,389			119,389
Unissued common units under incentive plans				3,000			3,000
Distributions paid to common limited partners and the general partner		(64)		(3,144)			(3,208)
Net loss attributable to common limited partners and the general partner subsequent to the transfer of assets on March 5, 2012		(463)		(22,702)			(23,165)
Other comprehensive income						4,316	4,316
Balance at June 30, 2012	657,715	$ 8,135	32,228,059	$ 521,002	$	$ 34,245	$ 563,382

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)

	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$ (22,915)	$ 15,240
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	19,930	15,948
Non-cash (gain) loss on derivative value, net	(13,092)	51,531
(Gain)/loss on asset sales and disposal	7,021	(48)
Non-cash compensation expense	3,000	
Amortization of deferred financing costs	529	
Changes in operating assets and liabilities:		
Accounts receivable and prepaid expenses and other	32,210	(4,735)
Accounts payable and accrued liabilities	(63,960)	(42,902)
Net cash provided by (used in) operating activities	(37,277)	35,034
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(45,652)	(14,382)
Net cash paid for acquisitions	(205,236)	
Net cash used in investing activities	(250,888)	(14,382)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	168,000	
Repayments under credit facilities	(24,000)	
Net investment from owners	5,625	
Net distribution to owners		27,285
Distributions paid to unit holders	(3,208)	
Net proceeds from issuance of common limited partner units	119,389	
Deferred financing costs and other	(7,206)	
Net cash provided by financing activities	258,600	27,285
Net change in cash and cash equivalents	(29,565)	47,937
Cash and cash equivalents, beginning of year	54,708	
Cash and cash equivalents, end of period	$ 25,143	$ 47,937

See accompanying notes to consolidated combined financial statements.

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ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED COMBINED FINANCIAL STATEMENTS

June 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 June 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 63.7% limited partnership interest (20,960,000 limited partner units) in the Partnership (see Note 16).

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 six months ended June 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 June 30, 2012, the statement of operations for the three months ended June 30, 2012, and the portion of the consolidated combined statement of operations for the six months ended June 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 six months ended June 30, 2012 prior to the transfer of assets on March 5, 2012 and the combined statement of operations for the three and six months ended June 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

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 (See Note 3);

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 six months ended June 30, 2012 and 2011 represent actual results in all material respects (see *Revenue Recognition* accounting policy for further description).

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 June 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 $3.9 million of inventory at June 30, 2012 and December 31, 2011 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.

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

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 or six months ended June 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 or six months ended June 30, 2012 and 2011.

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.

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

	June 30, 2012	December 31, 2011	Estimated Useful Lives In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(12,935)	(12,843)	
Net Carrying Amount	$ 1,409	$ 1,501	

Amortization expense on intangible assets was not material for the three months ended June 30, 2012 and $0.1 million for the three months ended June 30, 2011 and $0.1 million and $0.3 million for the six months ended June 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 June 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 six months ended June 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 six months ended June 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.

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 is required to consider 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).

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Other Assets

The Partnership had $8.1 million and $0.9 million of other assets at June 30, 2012 and December 31, 2011, respectively, which were included on the Partnership s consolidated combined balance sheets. Of the $8.1 million of other assets at June 30, 2012, $6.7 million related to deferred financing costs (net of $1.1 million of accumulated amortization) associated with the Partnership s credit facility in 2012, which are recorded at cost and amortized over the term of the respective debt agreement. The Partnership recorded $0.4 million and $0.5 million of amortization of deferred financing costs during the three and six months ended June 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 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.

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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Net income (loss)	$ (16,707)	$ 7,775	$ (22,915)	$ 15,240
Income applicable to owners interest (period prior to transfer of assets on March 5, 2012)		(7,775)	(250)	(15,240)
Net loss attributable to common limited partners and the general partner	(16,707)		(23,165)	
Less: General partner s interest	334		463	

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Net loss attributable to common limited partners	(16,373)		(22,702)	
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	$ (16,373)	$	$ (22,702)	$

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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Weighted average number of common limited partner units basic	30,307		29,367	
Add effect of dilutive incentive awards				
Weighted average number of common limited partner units diluted	30,307		29,367	

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.

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 June 30, 2012 and December 31, 2011 of $11.1 million and $12.6 million, respectively, which were included in accounts receivable within the Partnership s consolidated combined balance sheets.

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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 December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (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 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 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

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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.

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 certain amounts subject to a reconciliation period following the consummation of the transaction. The reconciliation period was assumed by the Partnership on March 5, 2012 and remains ongoing at June 30, 2012, and certain amounts included within the contractual cash transaction adjustment are in dispute between the parties. The resolution of the disputed amounts could result in the Partnership being required to repay a portion of the cash transaction adjustment (see Note 11). Including the cash transaction adjustment, the net book value of the Transferred Business was approximately $522.9 million.

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

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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

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 ACQUISITION

On April 30, 2012, the Partnership acquired 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 placement exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (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). All 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

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 Carrizo acquisition, including the borrowings under the credit facility and private placement of common 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 acquisition had occurred on January 1, 2011 or the results that will be attained in future periods (in thousands, except per share data; unaudited):

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	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Total revenues and other	$ 38,236	$ 53,566	$ 115,024	$ 111,913
Net income (loss)	(21,215)	11,009	(29,899)	20,586
Net income (loss) attributable to common limited partners and the general partner	(21,215)		(28,408)	
Net income (loss) attributable to common limited partners per unit:				
Basic	$ (0.65)	$	$ (0.86)	$
Diluted	$ (0.65)	$	$ (0.86)	$

NOTE 5 PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2012	December 31, 2011	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 131,734	$ 61,587	
Pre-development costs	1,328	2,540	
Wells and related equipment	1,003,930	828,780	
Total proved properties	1,136,992	892,907	
Unproved properties	40,805	43,253	
Support equipment	10,714	9,413	
Total natural gas and oil properties	1,188,511	945,573	
Pipelines, processing and compression facilities	31,936	32,149	2 40
Rights of way	84	84	20 40
Land, buildings and improvements	6,671	4,822	3 40
Other	8,653	1,180	3 10
	1,235,855	983,808	
Less accumulated depreciation, depletion and amortization	(483,350)	(462,925)	
	$ 752,505	$ 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 six months ended June 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.

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.

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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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Asset retirement obligations, beginning of period	$ 46,538	$ 43,315	$ 45,779	$ 42,673
Liabilities incurred	3,911		4,092	93
Liabilities settled	(132)	(33)	(250)	(132)
Accretion expense	729	650	1,425	1,298
Asset retirement obligations, end of period	$ 51,046	$ 43,932	$ 51,046	$ 43,932

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 six months ended June 30, 2012, the Partnership incurred $3.9 million of future plugging and abandonment costs related to the acquisition of assets from Carrizo (see Note 4).

NOTE 7 DEBT

Credit Facility

At June 30, 2012, the Partnership had a senior secured credit facility with a syndicate of banks with a borrowing base of $250.0 million with $144.0 million outstanding (see Note 16). 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 June 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 June 30, 2012, the weighted average interest rate was 3.1%.

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 June 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 1.4 to 1.0, its ratio of Total Funded Debt to EBITDA was 1.6 to 1.0 and its ratio of EBITDA to Consolidated Interest Expense was 38.1 to 1.0 at June 30, 2012.

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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 $35.6 million and $29.9 million at June 30, 2012 and December 31, 2011, respectively. Of the $34.2 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 June 30, 2012, if the fair values of the instruments remain at current market values, the Partnership will reclassify $14.5 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 $19.7 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.

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):

	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
Offsetting Derivative Assets			
As of June 30, 2012			
Current portion of derivative assets	$ 17,098	$ (971)	$ 16,127
Long-term portion of derivative assets	24,177	(4,623)	19,554
Long-term portion of derivative liabilities	26	(26)	

Total derivative assets	$ 41,301	$ (5,620)	$ 35,681

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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

	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
Offsetting Derivative Liabilities			
As of June 30, 2012			
Current portion of derivative assets	$ (971)	$ 971	$
Long-term portion of derivative assets	(4,623)	4,623	
Long-term portion of derivative liabilities	(154)	26	(128)
Total derivative liabilities	$ (5,748)	$ 5,620	$ (128)
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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Gain (loss) recognized in accumulated OCI	$ (514)	$ 6,407	$ 13,655	$ 6,849
Gain reclassified from accumulated OCI into income	$ (6,739)	$ (1,578)	$ (9,339)	$ (9,309)

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 three and six months ended June 30, 2012, the Partnership recorded approximately $3.6 million and $4.6 million, respectively, 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.

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The Partnership recognized gains of $6.7 million and $1.6 million for the three months ended June 30, 2012 and 2011, respectively, and $9.3 million for both the six months ended June 30, 2012 and 2011 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 six months ended June 30, 2012 and 2011 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At June 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 (in thousands)(2)**
2012	9,060,000	$ 3.550	$ 5,347
2013	11,160,000	$ 4.076	5,499
2014	10,800,000	$ 4.373	4,569
2015	7,350,000	$ 4.430	2,135
			$ 17,550

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	2,160,000	$ 4.074	$ 2,506
2012	Calls sold	2,160,000	$ 5.279	(22)
2013	Puts purchased	5,520,000	$ 4.395	5,768
2013	Calls sold	5,520,000	$ 5.443	(538)
2014	Puts purchased	3,840,000	$ 4.221	3,004
2014	Calls sold	3,840,000	$ 5.120	(1,072)
2015	Puts purchased	3,480,000	$ 4.234	2,903
2015	Calls sold	3,480,000	$ 5.129	(1,594)
				$ 10,955

Natural Gas Put Options

Production Period Ending	**Option Type**	**Volumes**	**Average Fixed Price**	**Fair Value Asset**

December 31,		(mmbtu)(1)	(per mmbtu)(1)	(in thousands)(2)
2012	Puts purchased	2,940,000	$ 2.802	$ 522
2013	Puts purchased	3,180,000	$ 3.450	1,262
2014	Puts purchased	1,800,000	$ 3.800	933
2015	Puts purchased	1,440,000	$ 4.000	978
2016	Puts purchased	1,440,000	$ 4.150	1,178
				$ 4,873

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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	13,500	$ 103.804	$ 286
2013	18,600	$ 100.669	227
2014	36,000	$ 97.693	355
2015	45,000	$ 89.504	114
			$ 982

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	30,000	$ 90.000	$ 274
2012	Calls sold	30,000	$ 117.912	(18)
2013	Puts purchased	60,000	$ 90.000	693
2013	Calls sold	60,000	$ 116.396	(173)
2014	Puts purchased	41,160	$ 84.169	471
2014	Calls sold	41,160	$ 113.308	(217)
2015	Puts purchased	29,250	$ 83.846	365
2015	Calls sold	29,250	$ 110.654	(202)
				$ 1,193
			Total net asset	$ 35,553

(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 June 30, 2012, remaining hedge monetization cash proceeds of $20.2 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 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 June 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 June 30, 2012, net unrealized derivative assets of $4.2 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

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

	June 30, 2012	**December 31, 2011**
Current portion of derivative payable to Drilling Partnerships:		
Hedge monetization proceeds	$ (15,210)	$ (20,900)
Hedge contracts covering future natural gas production	(670)	
Long-term portion of derivative payable to Drilling Partnerships:		
Hedge monetization proceeds	(4,975)	(15,272)
Hedge contracts covering future natural gas production	(3,533)	
	$ (24,388)	$ (36,172)

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At June 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. 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.

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

	Level 1	Level 2	Level 3	Total
As of June 30, 2012				
Derivative assets, gross				
Commodity swaps	$	$ 20,445	$	$ 20,445
Commodity puts		4,872		4,872
Commodity options		15,984		15,984
Total derivative assets, gross		41,301		41,301
Derivative liabilities, gross				
Commodity swaps		(1,913)		(1,913)
Commodity puts				
Commodity options		(3,835)		(3,835)
Total derivative liabilities, gross		(5,748)		(5,748)

Total derivatives, fair value, net	$	$ 35,553	$	$ 35,553

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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. 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 that were measured at fair value on a nonrecurring basis for the three and six months ended June 30, 2012 and 2011 were as follows (in thousands):

	Three Months Ended June 30,			
	2012		**2011**	
	Level 3	**Total**	**Level 3**	**Total**
Asset retirement obligations	$ 3,911	$ 3,911	$	$
Total	$ 3,911	$ 3,911	$	$

	Six Months Ended June 30,			
	2012		**2011**	
	Level 3	**Total**	**Level 3**	**Total**
Asset retirement obligations	$ 4,092	$ 4,092	$ 93	$ 93
Total	$ 4,092	$ 4,092	$ 93	$ 93

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 or six months ended June 30, 2012 and 2011 (see Note 5).

In April 2012, the Partnership completed the acquisition of certain oil and gas assets from Carrizo (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

Relationship with the Partnership s Sponsored Investment Partnerships. 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 Partnership s revenue and costs and expenses according to the respective partnership agreements.

Joint Venture Agreement with Subsidiaries of Equal Energy, Ltd. 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 (see Note 7). 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 serves as the drilling and completion operator, while Equal will undertake production operations, including water disposal. Subsequent to the formation of the joint venture, each party can contribute acreage to the joint venture through the establishment of an area of mutual interest closely surrounding Equal s existing acreage position. The Partnership proportionately consolidates its 50% ownership interest in the joint venture.

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 June 30, 2012 and 2011, $1.4 million and $1.3 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 six months ended June 30, 2012 and 2011, $1.8 million and $2.7 million, respectively, 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 and remains ongoing at June 30, 2012, as certain amounts included within the contractual cash transaction adjustment are in dispute between the parties. The Partnership believes the amounts included within the contractual cash transaction adjustment are appropriate and is currently engaged in an on-going reconciliation process with Chevron. The resolution of the disputed amounts could result in the Partnership being required to repay a portion of the cash transaction adjustment (see Note 3). According to the transaction agreement, should the Partnership and Chevron not be able to come to an agreement during the reconciliation process, the two parties will enter into arbitration with a neutral public accounting firm. At June 30, 2012, the Partnership believes the range of loss associated with the disputed balances is between zero and $45.0 million.

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 June 30, 2012, the Partnership is committed to expend approximately $1.9 million, principally on drilling and completion expenditures.

Legal Proceedings

The Partnership is 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

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 Securities and Exchange Commission by October 30, 2012 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by December 31, 2012. If the Partnership does not meet the aforementioned deadline for the common units to be declared effective, the common unit holders subject to the registration rights agreement will receive liquidated damages of 0.50% of the gross proceeds from the private placement, or $0.6 million, for the first 30-day period after December 31, 2012, increasing by an additional 0.50% per 30-day period thereafter, up to a maximum of 2.0% of the gross proceeds of the private placement per 30-day period. On July 11, 2012, the Partnership filed a registration statement with the Securities and Exchange Commission for the common units subject to the registration rights agreement in satisfaction of one of the requirements of the registration rights agreement noted previously.

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

(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 June 28, 2012, the Partnership declared a cash distribution of $0.40 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2012. The $13.2 million distribution, including $0.3 million to the general partner, will be paid on August 14, 2012 to unitholders of record at the close of business on July 12, 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 June 30, 2012, the Partnership had 2,309,976 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 590,024 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.

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 June 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 June 30, 2012, 202,619 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at June 30, 2012 include DERs. During the three and six months ended June 30, 2012, respectively, the Partnership paid $400 with respect to the 2012 LTIP s DERs. No amounts were paid during the three and six months ended June 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 and Six Months Ended June 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		$		$
Granted	810,476	24.69		
Vested [1]				
Forfeited				
Outstanding, end of period[2][3]	810,476	$ 24.69		$
Non-cash compensation expense recognized (in thousands)		$ 1,740		$

(1) No phantom unit awards vested during the three and six months ended June 30, 2012 and 2011.
(2) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2012 was $21.9 million.
(3) There was $12,000 classified within accrued liabilities on the Partnership s consolidated combined balance sheet at June 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 June 30, 2012.

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 exercise price may be paid by the Participant. Unit option awards expire 10 years from the date of grant. Through June 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 374,875 unit options outstanding under the 2012 LTIP at June 30, 2012 that will vest within the following twelve months. No cash was received from the exercise of options for the three and six months ended June 30, 2012 and 2011.

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

	Three and Six Months Ended June 30, 2012		2011	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period		$		$
Granted	1,499,500	24.67		
Exercised[1]				
Forfeited				
Outstanding, end of period[2][3]	1,499,500	$ 24.67		$

Options exercisable, end of period[4]	$	$
Non-cash compensation expense recognized (in thousands)	$ 1,274	$

(1) No options were exercised during the three and six months ended June 30, 2012 and 2011.

(2) The weighted average remaining contractual life for outstanding options at June 30, 2012 was 9.9 years.

(3) The aggregate intrinsic value of options outstanding at June 30, 2012 was approximately $3.5 million.

(4) No options were exercisable at June 30, 2012.

At June 30, 2012, the Partnership had approximately $13.4 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 and Six Months Ended June 30, 2012
Expected dividend yield	1.5%
Expected unit price volatility	47.0%
Risk-free interest rate	1.0%
Expected term (in years)	6.25
Fair value of unit options granted	$ 9.79

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.

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 June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Gas and oil production:				
Revenues	$ 19,460	$ 17,723	$ 36,624	$ 35,349
Operating costs and expenses	(4,447)	(4,042)	(8,952)	(7,963)
Depreciation, depletion and amortization expense	(9,520)	(7,178)	(17,087)	(13,744)
Segment income	$ 5,493	$ 6,503	$ 10,585	$ 13,642
Well construction and completion:				
Revenues	$ 12,241	$ 10,954	$ 55,960	$ 28,679
Operating costs and expenses	(10,606)	(9,284)	(48,301)	(24,305)
Segment income	$ 1,635	$ 1,670	$ 7,659	$ 4,374
Other partnership management:[(1)]				
Revenues	$ 5,344	$ 11,336	$ 15,562	$ 22,429
Operating costs and expenses	(6,367)	(7,437)	(13,471)	(15,531)
Depreciation, depletion and amortization expense	(1,302)	(1,069)	(2,843)	(2,204)
Segment income (loss)	$ (2,325)	$ 2,830	$ (752)	$ 4,694
Reconciliation of segment income (loss) to net income (loss):				
Segment income (loss):				
Gas and oil production	$ 5,493	$ 6,503	$ 10,585	$ 13,642
Well construction and completion	1,635	1,670	7,659	4,374
Other partnership management	(2,325)	2,830	(752)	4,694
Total segment income	4,803	11,003	17,492	22,710
General and administrative expenses[(2)]	(20,538)	(3,276)	(32,280)	(7,518)
Gain (loss) on asset sales and disposal[(2)]	(16)	48	(7,021)	48

Interest expense[2]	(956)		(1,106)	
Net income (loss)	$ (16,707)	$ 7,775	$ (22,915)	$ 15,240
Capital expenditures				
Gas and oil production	$ 23,260	$ 3,734	$ 40,179	$ 8,472
Other partnership management	691	1,279	1,018	2,431
Corporate and other	2,743	1,637	4,455	3,479
Total capital expenditures	$ 26,694	$ 6,650	$ 45,652	$ 14,382

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	June 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	$ 792,026	$ 593,320
Well construction and completion	6,988	6,987
Other partnership management	45,617	44,981
Corporate and other	39,221	55,825
	$ 883,852	$ 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 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

Acquisition of Titan Operating, L.L.C. On July 25, 2012, the Partnership acquired certain proved reserves and associated assets in the Barnett Shale from Titan Operating, L.L.C. (Titan) 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 fair value of the units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments. 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 initial accounting for the business combination is not complete pending detailed analyses of the facts and circumstances that existed as of the acquisition date. Also, the Partnership entered into an amendment to its senior secured revolving credit facility (see Note 7) on July 26, 2012 to increase the borrowing base from $250.0 million to $310.0 million.

The Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the Securities and Exchange Commission 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. If the Partnership does not meet the aforementioned deadline for the registration statement to be declared effective, the common unit holders subject to the registration rights agreement will receive liquidated damages of 0.50% of the gross proceeds from the private placement determined based on a per unit price of $26.03, or $1.0 million, for the first 30-day period after March 31, 2013, increasing by an additional 0.50% per 30-day period thereafter, up to a maximum of 2.0% of the gross proceeds of the private placement per 30-day period.

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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 June 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 63.7% limited partnership ownership interest (20,960,000 limited partner units) in us (see Subsequent Events).

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 June 30, 2012, the statement of operations for the three months ended June 30, 2012, and the portion of the consolidated combined statement of operations for the six months ended June 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 six months ended June 30, 2012 prior to the transfer of assets on March 5, 2012 and the combined statement of operations for the three and six months ended June 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 (see Note 3 in Item 1. Financial Statements). 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

Acquisition of Titan Operating, L.L.C. On July 25, 2012, we acquired certain proved reserves and associated assets in the Barnett Shale from Titan Operating, L.L.C. (Titan) for 3.8 million of our 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 fair value of the units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments. 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. Also, we entered into an amendment to our senior secured revolving credit facility (see Credit Facility) on July 26, 2012 to increase the borrowing base from $250.0 million to $310.0 million

We entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the Securities and Exchange Commission 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. If we do not meet the aforementioned deadline for the registration statement to be declared effective, the common unit holders subject to the registration rights agreement will receive liquidated damages of 0.50% of the gross proceeds from the private placement determined based on a per unit price of $26.03, or $1.0 million, for the first 30-day period after March 31, 2013, increasing by an additional 0.50% per 30-day period thereafter, up to a maximum of 2.0% of the gross proceeds of the private placement per 30-day period.

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RECENT DEVELOPMENTS

Cash Distribution. On June 28, 2012, we declared a cash distribution of $0.40 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended June 30, 2012. The $13.2 million distribution will be paid on August 14, 2012 to unitholders of record at the close of business on July 12, 2012.

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. Our common units issued in the private placement 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 Securities and Exchange Commission by October 30, 2012 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by December 31, 2012. If we do not meet the aforementioned deadline for the common units to be declared effective, the common unit holders subject to the registration rights agreement will receive liquidated damages of 0.50% of the gross proceeds from the private placement, or $0.6 million, for the first 30-day period after December 31, 2012, increasing by an additional 0.50% per 30-day period thereafter, up to a maximum of 2.0% of the gross proceeds of the private placement per 30-day period.

Joint Venture Agreement with Subsidiaries of Equal Energy, Ltd. In April 2012, we acquired a 50% interest in approximately 14,500 net undeveloped acres in the oil and natural gas liquids 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 closing of the acquisition, we entered into a participation and development agreement with Equal for future drilling in the Mississippi Lime play and both parties can contribute acreage to the joint venture through the establishment of an area of mutual interest closely surrounding Equal s existing acreage position.

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 to $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 $1,500, 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%.

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, 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 June 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 acquisition of assets from Carrizo in April 2012 (see Recent Developments);

the Mississippi Lime play in northwestern Oklahoma, an oil and natural gas liquids rich area, in which we acquired a 50% joint venture interest in 14,500 net undeveloped acres in April 2012 (see Recent Developments);

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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.

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 six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Gross wells drilled:				
Appalachia	5		14	3
Mississippi Lime	2		2	
Niobrara			51	17
	7		67	20
Our share of gross wells drilled[1]:				
Appalachia	2		4	1
Mississippi Lime	1		1	
Niobrara			15	5
	3		20	6
Gross wells turned in line:				
Appalachia	12		33	1
New Albany/Antrim		1		13
Niobrara	23	12	72	30
	35	13	105	44

(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 six months ended June 30, 2012 and 2011:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Production:[1][2]				
Appalachia:[3]				
Natural gas (MMcf)	3,163	2,567	6,020	5,197
Oil (000 s Bbls)	26	30	54	54
Natural gas liquids (000 s Bbls)	39	43	78	85

Total (MMcfe)	3,557	3,007	6,810	6,030
Barnett:[4]				
Natural gas (MMcf)	1,775		1,775	
Oil (000 s Bbls)				
Natural gas liquids (000 s Bbls)	3		3	
Total (MMcfe)	1,793		1,793	
New Albany/Antrim:				
Natural gas (MMcf)	275	291	550	582
Total (MMcfe)	275	291	550	582

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Niobrara:				
Natural gas (MMcf)	67	36	125	53
Total (MMcfe)	67	36	125	53
Total:				
Natural gas (MMcf)	5,280	2,894	8,470	5,833
Oil (000 s Bbls)	26	30	54	54
Natural gas liquids (000 s Bbls)	42	43	81	85
Total (MMcfe)	5,691	3,334	9,278	6,665
Production per day: (1)(2)				
Appalachia:(3)				
Natural gas (Mcfd)	34,760	28,208	33,075	28,714
Oil (Bpd)	290	334	297	298
Natural gas liquids (Bpd)	431	472	427	469
Total (Mcfed)	39,086	33,042	37,419	33,314
Barnett:(4)				
Natural gas (Mcfd)	28,629		28,629	
Oil (Bpd)				
Natural gas liquids (Bpd)	47		47	
Total (Mcfed)	28,912		28,912	
New Albany/Antrim:				
Natural gas (Mcfd)	3,023	3,192	3,025	3,218
Total (Mcfed)	3,023	3,192	3,025	3,218
Niobrara:				
Natural gas (Mcfd)	734	399	688	293
Total (Mcfed)	734	399	688	293
Total: (4)				
Natural gas (Mcfd)	58,022	31,799	46,541	32,225
Oil (Bpd)	290	334	297	298
Natural gas liquids (Bpd)	463	472	443	469
Total (Mcfed)	62,541	36,633	50,981	36,825

(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 data for Barnett for the three and six months ended June 30, 2012 represents average volumes recognized for the 62-day period from April 30, 2012, the date of acquisition, through June 30, 2012. Total production per day represents total production volume over the 91 and 182 days within the three and six months ended June 30, 2012, respectively.

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 six months ended June 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 June 30,		**Six Months Ended June 30,**	
	2012	**2011**	**2012**	**2011**
Production revenues (in thousands):				
Appalachia:[1]				
Natural gas revenue	$ 9,727	$ 10,947	$ 21,217	$ 23,162
Oil revenue	2,591	3,027	5,378	5,086
Natural gas liquids revenue	1,575	2,224	3,253	4,069
Total revenues	$ 13,893	$ 16,198	$ 29,848	$ 32,317

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Barnett:				
Natural gas revenue	$ 3,940	$	$ 3,940	$
Oil revenue	2		2	
Natural gas liquids revenue	147		147	
Total revenues	$ 4,089	$	$ 4,089	$
New Albany/Antrim:				
Natural gas revenue	$ 1,230	$ 1,330	$ 2,290	$ 2,769
Total revenues	$ 1,230	$ 1,330	$ 2,290	$ 2,769
Niobrara:				
Natural gas revenue	$ 248	$ 195	$ 397	$ 263
Total revenues	$ 248	$ 195	$ 397	$ 263
Total:				
Natural gas revenue	$ 15,145	$ 12,472	$ 27,844	$ 26,194
Oil revenue	2,593	3,027	5,380	5,086
Natural gas liquids revenue	1,722	2,224	3,400	4,069
Total revenues	$ 19,460	$ 17,723	$ 36,624	$ 35,349
Average sales price:(2)				
Natural gas (per Mcf):				
Total realized price, after hedge(3)	$ 3.49	$ 5.15	$ 3.81	$ 5.31
Total realized price, before hedge(3)	$ 2.03	$ 5.05	$ 2.76	$ 4.64
Oil (per Bbl):				
Total realized price, after hedge	$ 98.31	$ 99.70	$ 99.89	$ 94.32
Total realized price, before hedge	$ 94.39	$ 99.70	$ 97.60	$ 92.25
Natural gas liquids (per Bbl) total realized price:	$ 40.85	$ 51.77	$ 42.22	$ 47.95
Production costs (per Mcfe):(2)				
Appalachia:(1)				
Lease operating expenses(4)	$ 0.83	$ 1.03	$ 0.93	$ 1.00
Production taxes	0.06	0.03	0.09	0.05
Transportation and compression	0.30	0.50	0.31	0.48
	$ 1.19	$ 1.55	$ 1.32	$ 1.52
Barnett:				
Lease operating expenses	$ 0.41	$	$ 0.41	$
Production taxes	0.19		0.19	
Transportation and compression	0.30		0.30	
	$ 0.90	$	$ 0.90	$
New Albany/Antrim:				
Lease operating expenses	$ 1.04	$ 1.33	$ 1.12	$ 1.22
Production taxes	0.13	0.15	0.10	0.12
Transportation and compression	0.03	0.12	0.03	0.10
	$ 1.20	$ 1.61	$ 1.25	$ 1.44

Niobrara:				
Lease operating expenses	$ 0.99	$ 0.61	$ 1.22	$ 0.62
Production taxes	0.27	0.03	0.18	0.02
Transportation and compression	0.43	0.22	0.39	0.25
	$ 1.69	$ 0.85	$ 1.79	$ 0.89
Total:				
Lease operating expenses[4]	$ 0.71	$ 1.05	$ 0.84	$ 1.01
Production taxes	0.11	0.04	0.11	0.05
Transportation and compression	0.29	0.46	0.29	0.45
	$ 1.11	$ 1.55	$ 1.24	$ 1.51

(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 its investment partnerships for the three and six months ended June 30, 2012 and 2011. Including the effect of this subordination, the average realized gas sales price was $2.87 per Mcf ($1.40 per Mcf before the effects of financial hedging) and $4.31 per Mcf ($4.20 per Mcf before the effects of financial hedging) for the three months ended June 30, 2012 and 2011, respectively, and $3.29 per Mcf ($2.24 per Mcf before the effects of financial hedging) and $4.49 per Mcf ($3.82 per Mcf before the effects of financial hedging) for the six months ended June 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 six months ended June 30, 2012 and 2011. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.31 per Mcfe ($0.67 per Mcfe for total production costs) and $0.65 per Mcfe ($1.18 per Mcfe for total production costs) for the three months ended June 30, 2012 and 2011, respectively, and $0.54 per Mcfe ($0.94 per Mcfe for total production costs) and $0.65 per Mcfe ($1.17 per Mcfe for total production costs) for the six months ended June 30, 2012 and 2011, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $0.38 per Mcfe ($0.78 per Mcfe for total production costs) and $0.71 per Mcfe ($1.21 per Mcfe for total production costs) for three months ended June 30, 2012 and 2011, respectively, and were $0.56 per Mcfe ($0.96 per Mcfe for total production costs) and $0.70 per Mcfe ($1.19 per Mcfe for total production costs) for the six months ended June 30, 2012 and 2011, respectively.

Three Months Ended June 30, 2012 Compared with the Three Months Ended June 30, 2011. Total natural gas revenues were $15.1 million for the three months ended June 30, 2012, an increase of $2.6 million from $12.5 million for the three months ended June 30, 2011. This increase consisted of a $3.9 million increase attributable to production associated with the newly acquired Barnett Shale assets and a $2.5 million increase attributable to higher production volumes for legacy systems wells, partially offset by a $2.9 million decrease attributable to lower realized natural gas prices for production volume on legacy systems wells and a $0.9 million increase in gas revenues subordinated to the investor partners within our investment partnerships for the three months ended June 30, 2012 compared with the prior year period. Total oil revenues were $2.6 million for the three months ended June 30, 2012, a decrease of $0.4 million from $3.0 million for the comparable prior year period due primarily to lower production volumes during the current year period. Total natural gas liquids revenues were $1.7 million for the three months ended June 30, 2012, a decrease of $0.5 million from $2.2 million for the comparable prior year period due primarily to lower average natural gas liquids realized prices.

Appalachia production costs were $2.4 million for the three months ended June 30, 2012, a decrease of $1.1 million from $3.5 million for the three months ended June 30, 2011. This decrease was principally due to a $0.7 million increase in our net credit received against lease operating expenses from the subordination of our revenue within our investment partnerships and a $0.4 million decrease in water hauling and disposal costs due to timing of costs incurred.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Total natural gas revenues were $27.8 million for the six months ended June 30, 2012, an increase of $1.6 million from $26.2 million for the six months ended June 30, 2011. This increase consisted of a $3.9 million increase attributable to production associated with the newly acquired Barnett Shale assets, a $3.5 million increase attributable to higher production volumes for legacy systems wells and a $0.4 million decrease in gas revenues subordinated to the investor partners within our investment partnerships for the six months ended June 30, 2012 compared with the prior year period, partially offset by a $6.2 million decrease attributable to lower realized natural gas prices for production volume on legacy systems wells. Total oil revenues were $5.4 million for the six months ended June 30, 2012, an increase of $0.3 million from $5.1 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 $3.4 million for the six months ended June 30, 2012, a decrease of $0.7 million from $4.1 million for the comparable prior year period due primarily to lower average natural gas liquids realized prices.

Appalachia production costs were $6.4 million for the six months ended June 30, 2012, a decrease of $0.7 million from $7.1 million for the six months ended June 30, 2011. This decrease was principally due to a $0.5 million increase in our net credit received against lease operating expenses from the subordination of our revenue within our investment partnerships and a $0.4 million decrease in water hauling and disposal costs due to timing of costs incurred, partially offset by a $0.2 million increase in labor and other costs.

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 six months ended June 30, 2012 and 2011. There were no exploratory wells drilled during the three or six months ended June 30, 2012 and 2011:

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	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Drilling partnership investor capital:				
Raised	$ 3,000	$	$ 3,000	$
Deployed	$ 12,241	$ 10,954	$ 55,960	$ 28,679
Gross partnership wells drilled:				
Appalachia	5		14	3
Mississippi Lime	2		2	
Niobrara			51	17
Total	7		67	20
Net partnership wells drilled:				
Appalachia	5		14	3
Mississippi Lime	1		1	
Niobrara			51	17
Total	6		66	20

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 June 30, 2012	Three Months Ended June 30, 2011	Six Months Ended June 30, 2012	Six Months Ended June 30, 2011
Average construction and completion:				
Revenue per well	$ 817	$ 5,160	$ 712	$ 954
Cost per well	708	4,373	615	809
Gross profit per well	$ 109	$ 787	$ 97	$ 145
Gross profit margin	$ 1,635	$ 1,670	$ 7,659	$ 4,374
Partnership net wells associated with revenue recognized[1]:				
Appalachia	6	1	15	2
Mississippi Lime	1		1	
New Albany/Antrim		1		3
Niobrara	8		63	25
	15	2	79	30

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

Three Months Ended June 30, 2012 Compared with the Three Months Ended June 30, 2011. Well construction and completion segment margin was $1.6 million for the three months ended June 30, 2012, a decrease of $0.1 million from $1.7 million for the three months ended June 30, 2011. This decrease consisted of a $1.5 million decrease associated with lower gross profit margin per well, partially offset by a $1.4 million increase related to an increased number of wells recognized for revenue within our investment partnerships. Average revenue and cost per well decreased between periods due primarily to lower capital deployed for Marcellus Shale wells within the drilling partnerships during second quarter 2012, but an increase in capital deployed for Niobrara wells, which have a lower cost per well in comparison to the Marcellus Shale wells. As our drilling contracts with the investment partnerships are on a cost-plus basis, an increase or decrease in its average cost per well also results in a proportionate increase or decrease in its average revenue per well, which directly affects the number of wells we drill.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Well construction and completion segment margin was $7.7 million for the six months ended June 30, 2012, an increase of $3.3 million from $4.4 million for the six months ended June 30, 2011. This increase consisted of a $4.7 million increase related to an increased number of wells recognized for revenue within our investment partnerships, partially offset by a $1.4 million decrease associated with lower gross profit margin per well. Average revenue and cost per well decreased between periods due to higher capital deployed for Niobrara Shale wells, which have a lower cost per well in comparison to Marcellus Shale wells, within the drilling partnerships during first six 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. The planned Fall 2010 drilling program was cancelled following AEI s announcement of the acquisition of the Transferred Business in November 2010.

Our consolidated combined balance sheet at June 30, 2012 includes $18.8 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 beginning 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 June 30, 2012 Compared with the Three Months Ended June 30, 2011. Administration and oversight fee revenues were $1.3 million for the three months ended June 30, 2012, which was consistent with $1.4 million for the three months ended June 30, 2011.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Administration and oversight fee revenues were $4.1 million for the six months ended June 30, 2012, an increase of $1.4 million from $2.7 million for the six months ended June 30, 2011. This increase was primarily due to 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 June 30, 2012 Compared with the Three Months Ended June 30, 2011. Well services revenues were $5.3 million for the three months ended June 30, 2012, an increase of $0.4 million from $4.9 million for three months ended June 30, 2011. Well services expenses were $2.4 million for the three months ended June 30, 2012, an increase of $0.7 million from $1.7 million for the three months ended June 30, 2011. The increase in well services revenue is primarily related to higher equipment rental revenue during the three months ended June 30, 2012 as compared with the comparable prior year period. The increase in well services expenses is primarily related to higher well labor costs.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Well services revenues were $10.3 million for the six months ended June 30, 2012, an increase of $0.2 million from $10.1 million for the six months ended June 30, 2011. Well services expenses were $4.8 million for the six months ended June 30, 2012, an increase of $0.8 million from $4.0 million for the six months ended June 30, 2011. The increase in well services revenue is primarily related to higher equipment rental revenue during the six months ended June 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 investment 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 direct investment 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%.

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Three Months Ended June 30, 2012 Compared with the Three Months Ended June 30, 2011. Our net gathering and processing expense for the three months ended June 30, 2012 was $1.1 million compared with $0.6 million for the three months ended June 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.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Our net gathering and processing expense for the six months ended June 30, 2012 was $2.5 million compared with $1.9 million for the six months ended June 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 June 30, 2012 Compared with the Three Months Ended June 30, 2011. Other, net expenses were $4.1 million for the three months ended June 30, 2012 compared with $12 thousand for the three months ended June 30, 2011. The $4.1 million net expense in the current period was primarily due to the premium amortization associated with derivative contracts which provided us with the option to enter into swap contracts up through May 31, 2012 (swaptions) for production volumes related to wells recently acquired from Carrizo (see Recent Developments). At June 30, 2012, the premium associated with these swaption contracts was fully amortized.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Other, net expenses were $5.1 million for the six months ended June 30, 2012 compared with $0.1 million for the six months ended June 30, 2011. The $5.0 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 June 30, 2012 Compared with the Three Months Ended June 30, 2011. Total general and administrative expenses increased to $20.5 million for the three months ended June 30, 2012 compared with $3.3 million for the three months ended June 30, 2011. This increase is primarily due to an $8.8 million increase in non-recurring transaction costs principally associated with the acquisition of certain assets from Carrizo (see Recent Developments), a $5.4 million increase related to a decrease in reimbursements associated with the expiration of our transition services agreement with Chevron, a $3.0 million increase in non-cash compensation expense and a $0.1 million increase related to consulting and other outside services.

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Total general and administrative expenses increased to $32.3 million for the six months ended June 30, 2012 compared with $7.5 million for the six months ended June 30, 2011. This increase was primarily due to an $11.2 million increase in non-recurring transaction costs associated with the Carrizo acquisition (see Recent Developments), an $8.8 million increase related to a decrease in reimbursements associated with the expiration of our transition services agreement with Chevron, a $3.0 million increase in non-cash compensation expense and a $1.8 million increase in salary and wages expenses related to the growth of our business.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to $10.8 million for the three months ended June 30, 2012 compared with $8.2 million for the comparable prior year period primarily due to a $2.3 million increase in our depletion expense.

Total depreciation, depletion and amortization increased to $19.9 million for the six months ended June 30, 2012 compared with $15.9 million for the comparable prior year period primarily due to a $3.4 million increase in our depletion expense.

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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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Depreciation, depletion and amortization:				
Depletion expense	$ 9,520	$ 7,178	$ 17,087	$ 13,744
Depreciation and amortization expense	1,302	1,069	2,843	2,204
	$ 10,822	$ 8,247	$ 19,930	$ 15,948
Depletion expense (in thousands):				
Total	$ 9,520	$ 7,178	$ 17,087	$ 13,744
Depletion expense as a percentage of gas and oil production revenue	49%	41%	47%	39%
Depletion per Mcfe	$ 1.67	$ 2.15	$ 1.84	$ 2.06

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 June 30, 2012, depletion expense increased $2.3 million to $9.5 million compared with $7.2 million for the three months ended June 30, 2011. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 49% for the three months ended June 30, 2012, compared with 41% for the three months ended June 30, 2011, 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 $1.67 for the three months ended June 30, 2012, a decrease of $0.48 per Mcfe from $2.15 for the three months ended June 30, 2011, primarily related to lower depletion expense per Mcfe for the assets acquired from Carrizo (see Recent Developments) and the addition of reserves for Marcellus Shale wells, which began production during March 2012. Depletion expense increased between periods principally due to an overall increase in production volume.

For the six months ended June 30, 2012, depletion expense increased $3.4 million to $17.1 million compared with $13.7 million for the six months ended June 30, 2011. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues was 47% for the six months ended June 30, 2012, compared with 39% for the six months ended June 30, 2011, 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 $1.84 for the six months ended June 30, 2012, a decrease of $0.22 per Mcfe from $2.06 for the six months ended June 30, 2011, primarily related to lower depletion expense per Mcfe for the assets acquired from Carrizo (see Recent Developments) and the addition of reserves for Marcellus Shale wells, which began production during March 2012. Depletion expense increased between periods principally due to an overall increase in production volume.

Interest expense

Three Months Ended June 30, 2012 Compared with the Three Months Ended June 30, 2011. Interest expense for the three months ended June 30, 2012 was $1.0 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).

Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011. Interest expense for the six months ended June 30, 2012 was $1.1 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 six months ended June 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 targets for us to maintain ownership of the South Knox processing plant, which our management decided in 2012 not to achieve 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 first six months of 2012.

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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 Six Months Ended June 30, 2012 Compared with the Six Months Ended June 30, 2011

Net cash used in operating activities of $37.3 million for the six months ended June 30, 2012 represented an unfavorable movement of $72.3 million from net cash provided by operating activities of $35.0 million for the comparable prior year period. The $72.3 million unfavorable movement in net cash provided by operating activities resulted from a $88.2 million unfavorable movement in net income excluding non-cash items, partially offset by a $15.9 million favorable movement in working capital. The $88.2 million unfavorable movement in net income excluding non-cash items included a $64.6 million unfavorable movement in non-cash (gain) loss on derivative value and a $38.2 million decrease in net income, partially offset by a $7.1 million increase in loss on asset disposal, a $4.0 million increase in depreciation, depletion and amortization expense, a $3.0 million increase in non-cash stock compensation, and a $0.5 million increase in amortization of deferred financing costs relating to our credit facility assumed by us from ATLS. The $64.6 million unfavorable movement in non-cash gain on derivative value is primarily related to a $51.5 million non-cash loss on derivative value during the six months ended June 30, 2011 resulting from the monetization of hedges prior to the acquisition of the Transferred Business from AEI and a $13.1 million non-cash gain on derivative value for the six months ended June 30, 2012 related to a decline in natural gas prices during the period. The $15.9 million favorable movement in working capital was principally due to a $36.9 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, partially offset by a $21.0 million unfavorable movement in accounts payable and other current liabilities primarily due to a decrease in liabilities associated with drilling contracts resulting from funds deployed related to our Fall 2011 drilling program during the six months ended June 30, 2012.

Net cash used in investing activities of $250.9 million for the six months ended June 30, 2012 represented an unfavorable movement of $236.5 million from net cash used in investing activities of $14.4 million for the comparable prior year period. This unfavorable movement was principally due to a $205.2 million unfavorable movement in net cash paid for acquisitions related to the Carrizo acquisition and the joint venture with Equal Energy and a $31.4 million unfavorable movement in capital expenditures. 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 $258.6 million for the six months ended June 30, 2012 represented a favorable movement of $231.3 million from net cash used in financing activities of $27.3 million for the comparable prior year period. This movement was principally due to an increase of $168.0 million in borrowings under our credit facility, a $119.4 increase in net proceeds from issuance of common units, a net decrease of $27.3 million in the net distribution to AEI and an increase of $5.6 million for the net investment received from ATLS, partially offset by an increase of $24.0 million in repayments under our credit facility, a $7.2 million unfavorable movement in deferred financing costs and other resulting from the cash paid for credit facility financing costs and a $3.2 million increase in cash distributions paid to unitholders. 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.

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 June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Maintenance capital expenditures	$ 1,750	$ 3,567	$ 3,500	$ 5,233
Expansion capital expenditures	24,944	3,083	42,152	9,149
Total	$ 26,694	$ 6,650	$ 45,652	$ 14,382

During the three months ended June 30, 2012, our $26.7 million of total capital expenditures consisted primarily of $4.4 million for well costs, which consist principally of our investments in the investment partnerships, compared with $3.1 million for the prior year comparable period, $18.9 million of leasehold acquisition costs compared with $0.7 million for the prior year comparable period, $0.7 million of gathering and processing costs compared with $1.3 million for the prior year comparable period and $2.7 million of corporate and other compared with $1.6 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 subsequent to the formation of our joint venture with Equal during the three months ended June 30, 2012.

During the six months ended June 30, 2012, our $45.7 million of total capital expenditures consisted primarily of $17.5 million for well costs compared with $7.1 million for the prior year comparable period, $22.7 million of leasehold acquisition costs compared with $1.4 million for the prior year comparable period, $1.0 million of gathering and processing costs compared with $2.4 million for the prior year comparable period and $4.5 million of corporate and other compared with $3.5 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 Mississippi Lime acreage acquired subsequent to the formation of our joint venture with Equal during the six months ended June 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 June 30, 2012, we are committed to expend approximately $1.9 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 June 30, 2012, our off-balance sheet arrangements were limited to our letters of credit outstanding of $0.6 million and commitments to spend $1.9 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 June 30, 2012, we had a senior secured credit facility with a syndicate of banks with a borrowing base of $250.0 million and with $144.0 million outstanding. 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 June 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 June 30, 2012, the weighted average interest rate was 3.1%.

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 June 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 June 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 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. 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 counterparty. 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

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. Our common units issued in the private placement 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 Securities and Exchange Commission by October 30, 2012 and (b) cause the registration statement to be declared effective by the Securities and Exchange Commission by December 31, 2012. If we do not meet the aforementioned deadline for the common units to be declared effective, the common unit holders subject to the registration rights agreement will receive liquidated damages of 0.50% of the gross proceeds from the private placement, or $0.6 million, for the first 30-day period after December 31, 2012, increasing by an additional 0.50% per 30-day period thereafter, up to a maximum of 2.0% of the gross proceeds of the private placement per 30-day period. On July 11, 2012, we filed a registration statement with the Securities and Exchange Commission for the common units subject to the registration rights agreement in satisfaction of one of the requirements of the registration rights agreement noted previously.

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 or six months ended June 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 six months ended June 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 six months ended June 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 June 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 June 30, 2012, we had $144.0 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 $1.4 million impact on our consolidated combined interest expense for the twelve month period ending June 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 June 30, 2013 of approximately $4.2 million.

At June 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	9,060,000	$ 3.550
2013	11,160,000	$ 4.076
2014	10,800,000	$ 4.373
2015	7,350,000	$ 4.430

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (mmbtu)[1]	Average Floor and Cap (per mmbtu)[1]
2012	Puts purchased	2,160,000	$ 4.074
2012	Calls sold	2,160,000	$ 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	2,940,000	$ 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	13,500	$ 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	30,000	$ 90.000
2012	Calls sold	30,000	$ 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 June 30, 2012, our disclosure controls and procedures were effective at the reasonable assurance level.

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As of December 31, 2011, based on our evaluation under the COSO framework, management concluded that our internal control over financial reporting was ineffective for financial statement periods prior to February 17, 2011, the date of the acquisition of our principal assets and liabilities by ATLS from AEI, because the Atlas Energy E&P Operations financial statements we initially filed in our registration statement on Form 10 did not include general and administrative expenses prior to February 17, 2011. We had filed such financial statements without such expenses because the ATLS assets were not managed as a separate business segment. We revised the financial statements included in the Form 10 to include general and administrative expenses for periods prior to February 17, 2011 based on allocations that we believed reflected the approximate general and administrative costs of our underlying business segments. The failure to include these general and administrative expenses in our earlier filing was considered a material weakness in internal control financial reporting.

Subsequent to our discovery of the material weakness discussed above, we took steps to remediate the material weakness, including establishing a methodology for allocating general and administrative expenses for periods prior to February 17, 2011, implementing a review of accounting requirements related to Form 10 filings and establishing a policy on non-standard transactions. These steps, along with the completion of testing of internal controls over financial reporting in the periods since the material weakness was identified, have led to us concluding that the material weakness has been remediated during the first quarter of 2012.

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.

On April 30, 2012, we acquired certain assets from Carrizo (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

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)
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	Petro-Technical Services Agreement, dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.) and Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, 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)
10.3	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)
10.4	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)

10.5	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)
10.6	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)
10.7	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)
10.8	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)
10.9	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010.(6)
10.10	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010.(6)
10.11(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)
10.11(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)
10.11(c)	Joinder Agreement dated April 18, 2012 between ARP Barnett, LLC, ARP Oklahoma, LLC and Wells Fargo Bank, N.A.(9)
10.11(d)	Joinder Agreement dated April 30, 2012 between ARP Barnett Pipeline, LLC and Wells Fargo Bank, N.A.(9)
10.11(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)
10.11(f)	Joinder Agreement dated as of July 26, 2012, between Atlas Barnett, LLC and Wells Fargo Bank, N.A.(13)
10.12	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)
10.13	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P. (4)
10.14	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan(10)
10.15	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan(10)

10.16	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan(10)
10.17	Employment Agreement between Atlas Energy, L.P. and Edward E. Cohen dated as of May 13, 2011(5)
10.18	Employment Agreement between Atlas Energy, L.P. and Jonathan Z. Cohen dated as of May 13, 2011(5)
10.19	Employment Agreement between Atlas Energy, L.P. and Matthew A. Jones dated as of November 4, 2011(7)
10.20	Common Unit Purchase Agreement, dated as of March 15, 2012, among Atlas Resource Partners, L.P. and the various purchasers party thereto(11)
10.21	Registration Rights Agreement, dated as of April 30, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein(9)
10.22	Registration Rights Agreement, dated as of July 25, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein(13)
10.23	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.
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(14)
101.SCH	XBRL Schema Document(14)
101.CAL	XBRL Calculation Linkbase Document(14)
101.LAB	XBRL Label Linkbase Document(14)
101.PRE	XBRL Presentation Linkbase Document(14)
101.DEF	XBRL Definition Linkbase Document(14)

(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) 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: August 9, 2012	By: /s/ EDWARD E. COHEN Edward E. Cohen Chairman of the Board and Chief Executive Officer of the General Partner
Date: August 9, 2012	By: /s/ SEAN P. MCGRATH Sean P. McGrath Chief Financial Officer of the General Partner
Date: August 9, 2012	By: /s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback Chief Accounting Officer of the General Partner