Atlas Resource Partners, L.P.
Form 10-Q
November 08, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

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 November 4, 2013 was 59,447,058.

ATLAS RESOURCE PARTNERS, L.P.

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ON FORM 10-Q

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ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

ASSETS	September 30, 2013	December 31, 2012
Current assets:		
Cash and cash equivalents	$ 1,452	$ 23,188
Accounts receivable	59,669	38,718
Current portion of derivative asset	19,474	12,274
Subscriptions receivable	13,900	55,357
Prepaid expenses and other	11,610	9,063
Total current assets	106,105	138,600
Property, plant and equipment, net	2,175,754	1,302,228
Goodwill and intangible assets, net	32,843	33,104
Long-term derivative asset	28,500	8,898
Long-term derivative asset receivable from Drilling Partnerships	182	
Other assets, net	43,468	16,122
	$ 2,386,852	$ 1,498,952
LIABILITIES AND PARTNERS CAPITAL		
Current liabilities:		
Accounts payable	$ 74,686	$ 59,549
Advances from affiliates	23,559	5,853
Liabilities associated with drilling contracts		67,293
Current portion of derivative liability	318	
Current portion of derivative payable to Drilling Partnerships	4,932	11,293
Accrued well drilling and completion costs	47,149	47,637
Accrued liabilities	33,873	25,388
Total current liabilities	184,517	217,013
Long-term debt	948,279	351,425
Long-term derivative liability		888
Long-term derivative payable to Drilling Partnerships		2,429
Asset retirement obligations and other	84,127	65,191
Commitments and contingencies		
Partners Capital:		
General partner s interest	5,716	7,029
Preferred limited partners interests	183,325	96,155

Class C preferred limited partner warrants	1,176	
Common limited partners interests	929,474	737,253
Accumulated other comprehensive income	50,238	21,569
Total partners capital	1,169,929	862,006
	$ 2,386,852	$ 1,498,952

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Revenues:				
Gas and oil production	$ 80,332	$ 24,699	$ 173,490	$ 61,323
Well construction and completion	10,964	36,317	92,293	92,277
Gathering and processing	3,591	4,134	11,639	10,311
Administration and oversight	4,447	4,440	8,923	8,586
Well services	5,023	5,086	14,703	15,344
Other, net	(13,272)	67	(14,589)	(4,952)
Total revenues	91,085	74,743	286,459	182,889
Costs and expenses:				
Gas and oil production	29,419	7,295	63,670	16,247
Well construction and completion	9,534	31,581	80,255	79,882
Gathering and processing	4,395	4,558	13,767	13,185
Well services	2,386	2,232	7,009	7,076
General and administrative	31,983	16,147	63,767	48,427
Chevron transaction expense		7,670		7,670
Depreciation, depletion and amortization	41,656	13,918	85,061	33,848
Total costs and expenses	119,373	83,401	313,529	206,335
Operating loss	(28,288)	(8,658)	(27,070)	(23,446)
Interest expense	(10,748)	(1,423)	(22,145)	(2,529)
Gain (loss) on asset sales and disposal	(661)	2	(2,035)	(7,019)
Net loss	(39,697)	(10,079)	(51,250)	(32,994)
Preferred limited partner dividends	(3,564)	(1,221)	(7,592)	(1,221)
Net loss attributable to owner s interest, common limited partners and the general partner	$ (43,261)	$ (11,300)	$ (58,842)	$ (34,215)
Allocation of net income (loss):				
Portion applicable to owner s interest (period prior to the transfer of assets on March 5, 2012)	$	$	$	$ 250
Portion applicable to common limited partners and the general partner s interests (period subsequent to the transfer of assets on March 5, 2012)	(43,261)	(11,300)	(58,842)	(34,465)
Net loss attributable to owner s interest, common limited partners and the general partner	$ (43,261)	$ (11,300)	$ (58,842)	$ (34,215)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners interest	$ (44,073)	$ (11,074)	$ (60,977)	$ (33,776)

General partner s interest	812	(226)	2,135	(689)
Net loss attributable to common limited partners and the general partner	$ (43,261)	$ (11,300)	$ (58,842)	$ (34,465)
Net loss attributable to common limited partners per unit:				
Basic and Diluted	$ (0.74)	$ (0.32)	$ (1.21)	$ (1.06)
Weighted average common limited partner units outstanding:				
Basic and Diluted	59,440	35,068	50,197	31,865

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net loss	$ (39,697)	$ (10,079)	$ (51,250)	$ (32,994)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	15,064	(19,487)	33,093	(5,832)
Less: reclassification adjustment for realized gains of cash flow hedges in net loss	(1,145)	(6,114)	(4,424)	(15,453)
Total other comprehensive income (loss)	13,919	(25,601)	28,669	(21,285)
Comprehensive loss attributable to owner s interest, common and preferred limited partners and the general partner	$ (25,778)	$ (35,680)	$ (22,581)	$ (54,279)

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS CAPITAL

(in thousands, except unit data)

(Unaudited)

eral Interest	Preferred Limited Partners Interest				Common Limited Partners Interests		Class C Preferred Limited Partner Warrants		A
	Class B								
			Class C						Co
Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	
$ 7,029	3,836,554	$ 96,155			43,973,153	$ 737,253			
			3,749,986	$ 85,448					
					15,259,174	320,092	562,497	$ 1,176	
					212,331				
						10,199			
(3,448)		(5,870)				(75,632)			
						(1,461)			
2,135		6,177		1,415		(60,977)			
			3,749,986	$ 86,863				$	
$ 5,716	3,836,554	$ 96,462			59,444,658	$ 929,474	562,497	1,176	

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (51,250)	$ (32,994)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	85,061	33,848
Non-cash gain on derivative value, net	(7,675)	(17,013)
Loss on asset sales and disposal	2,035	7,019
Non-cash compensation expense	10,209	7,856
Amortization of deferred financing costs	8,608	1,028
Changes in operating assets and liabilities:		
Accounts receivable and prepaid expenses and other	35,665	16,105
Accounts payable and accrued liabilities	(69,463)	(30,836)
Net cash provided by (used in) operating activities	13,190	(14,987)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(203,996)	(73,379)
Net cash paid for acquisitions	(712,984)	(264,558)
Other	(5,676)	69
Net cash used in investing activities	(922,656)	(337,868)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	752,000	264,000
Repayments under credit facilities	(678,425)	(42,000)
Net proceeds from issuance of long-term debt	510,518	
Net investment from owners		5,625
Distributions paid to unit holders	(84,950)	(16,362)
Net proceeds from issuance of Class C preferred limited partner units and warrants	86,624	
Net proceeds from issuance of common limited partner units	320,092	119,389
Deferred financing costs, distribution equivalent rights and other	(18,129)	(8,239)
Net cash provided by financing activities	887,730	322,413
Net change in cash and cash equivalents	(21,736)	(30,442)
Cash and cash equivalents, beginning of year	23,188	54,708
Cash and cash equivalents, end of period	$ 1,452	$ 24,266

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2013

(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, crude oil and natural gas liquids (NGL) 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, crude oil and NGL production activities. At September 30, 2013, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

The Partnership was formed in October 2011 to own and operate substantially all of ATLS exploration and production assets, 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 accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2012 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 (U.S. GAAP) for interim reporting. They do not include all disclosures normally made in financial statements contained in Form 10-K. In management s opinion, all adjustments necessary for a fair presentation of the Partnership s financial position, results of operations and cash flows for the periods disclosed have been made. These interim consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Partnership s Annual Report on Form 10-K for the year ended December 31, 2012. Certain amounts in the prior year s financial statements have been reclassified to conform to the current year presentation. The results of operations for the three and nine months ended September 30, 2013 may not necessarily be indicative of the results of operations for the full year ending December 31, 2013.

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation and Combination

The Partnership s consolidated balance sheets at September 30, 2013 and December 31, 2012, the consolidated statements of operations for the three months ended September 30, 2013 and 2012, the consolidated statements of operations for the nine months ended September 30, 2013, and the portion of the consolidated statement of operations for the nine months ended September 30, 2012 subsequent to the transfer of assets on March 5, 2012 include the accounts of the Partnership and its wholly-owned subsidiaries. The portion of the consolidated statement of operations for the nine months ended September 30, 2012 prior to the transfer of assets on March 5, 2012 was 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. 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 balance sheets and related consolidated 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 prior to March 5, 2012. Actual balances and results could be different from those estimates. Transactions between the Partnership and other ATLS operations have been identified in the consolidated statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

In accordance with established practice in the oil and gas industry, the Partnership s consolidated 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 consolidated 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 financial statements in conformity with U.S. GAAP 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 financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership s consolidated 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 and liabilities assumed. Such estimates included estimated allocations made from the historical accounting records of ATLS in order to derive the historical financial statements of the Partnership for periods prior to March 5, 2012. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months financial results were recorded using estimated volumes and contract market prices. Differences between estimated and actual amounts are recorded in the following month s financial results. Management believes that the operating results presented for the three and nine months ended September 30, 2013 and 2012 represent actual results in all material respects (see Revenue Recognition).

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership s operations. In evaluating the realizability of its accounts receivable, the Partnership s management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer s current creditworthiness, as determined by management s review of the Partnership s customers credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At September 30, 2013 and December 31, 2012, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $5.3 million of inventory at September 30, 2013 and December 31, 2012, which was included within prepaid expenses and other current assets on the Partnership s consolidated 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 NGLs are converted to gas equivalent basis (Mcfe) at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

The Partnership s depletion expense is determined on a field-by-field basis using the units-of-production method. Depletion rates for leasehold acquisition costs are based on estimated proved reserves, and depletion rates for well and related equipment costs are based on proved developed reserves associated with each field. Depletion rates are determined based on reserve quantity estimates and the capitalized costs of undeveloped and developed producing properties. Capitalized costs of developed producing properties in each field are aggregated to include the Partnership s costs of property interests in proportionately consolidated Drilling 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 statements of operations. Upon the sale of an individual well, the Partnership credits the proceeds to accumulated depreciation and depletion within its consolidated 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 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 such uneconomic well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership s agreement. In general, the

Partnership will seek consent from the Drilling Partnership s limited partners to acquire the well interests from the Drilling Partnership based upon the Partnership s determination of fair market value.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2013 and 2012.

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, 2012, the Partnership recognized $9.5 million of asset impairments related to gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of these gas and oil properties being in excess of the Partnership s estimate of their fair values at December 31, 2012. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement. There were no impairments of proved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2013 and 2012.

Capitalized Interest

The Partnership capitalizes interest on borrowed funds related to capital projects only for periods that activities are in progress to bring these projects to their intended use. The weighted average interest rate used to capitalize interest on borrowed funds by the Partnership was 6.3% and 3.1% for the three months ended September 30, 2013 and 2012, respectively, and 6.1% and 3.5% for the nine months ended September 30, 2013 and 2012, respectively. The aggregate amount of interest capitalized by the Partnership was $3.6 million and $0.6 million for the three months ended September 30, 2013 and 2012, respectively, and $10.5 million and $1.0 million for the nine months ended September 30, 2013 and 2012, respectively.

Intangible Assets

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

The following table reflects the components of intangible assets being amortized at September 30, 2013 and December 31, 2012 (in thousands):

	September 30, 2013	December 31, 2012	Estimated Useful Lives In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(13,285)	(13,024)	
Net Carrying Amount	$ 1,059	$ 1,320	

Amortization expense on intangible assets was $0.1 million and approximately $45,000 for the three months ended September 30, 2013 and 2012, respectively, and $0.3 million and $0.1 million for the nine months ended September 30, 2013 and 2012, respectively. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2013 $0.4 million; 2014 $0.3 million; 2015 $0.2 million; 2016 $0.1 million and 2017 $0.1 million.

Goodwill

At September 30, 2013 and December 31, 2012, the Partnership had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the three and nine months ended September 30, 2013 and 2012.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units 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 and the available market data of the industry group. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership s market capitalization. The observed market prices of individual trades of an entity s equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership s, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership s management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership s industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership s industry to determine whether those valuations appear reasonable in management s judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the three and nine months ended September 30, 2013 and 2012, 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 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 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 also considers the estimated salvage value in the calculation of depreciation, depletion and amortization.

Income Taxes

The Partnership is not subject to U.S. federal and most state income taxes. The partners of the Partnership are liable for income tax in regard to their distributive share of the Partnership s taxable income. Such taxable income may vary substantially from net income reported in the accompanying consolidated financial statements. Certain corporate subsidiaries of the Partnership are subject to federal and state income tax. The federal and state income taxes related to the Partnership and these corporate subsidiaries were immaterial to the consolidated financial statements and are recorded in pre-tax income on a current basis only. Accordingly, no federal or state deferred income tax has been provided for in the accompanying consolidated financial statements.

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership s tax returns and disallows the recognition of tax positions not deemed to meet a more-likely-than-not threshold of being sustained by the applicable tax authority. The Partnership s management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership s policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the three and nine months ended September 30, 2013 and 2012.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of September 30, 2013.

Stock-Based Compensation

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

Net Income (Loss) Per Common Unit

Basic net income (loss) attributable to common limited partners per unit is computed by dividing net income (loss) attributable to common limited partners, which is determined after the deduction of the general partner s and the preferred unitholders interests, by the weighted average number of common limited partner units outstanding during the period. Net income (loss) attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, income (loss) attributable to preferred limited partners 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Net loss	$ (39,697)	$ (10,079)	$ (51,250)	$ (32,994)
Income applicable to owner s interest (period prior to transfer of assets on March 5, 2012)				(250)
Preferred limited partner dividends	(3,564)	(1,221)	(7,592)	(1,221)
Net loss attributable to common limited partners and the general partner	(43,261)	(11,300)	(58,842)	(34,465)
Less: General partner s interest	(812)	226	(2,135)	689
Net loss attributable to common limited partners	(44,073)	(11,074)	(60,977)	(33,776)
Less: Net income attributable to participating securities phantom units[1]				
Net loss utilized in the calculation of net loss attributable to common limited partners per unit	$ (44,073)	$ (11,074)	$ (60,977)	$ (33,776)

(1) Net income attributable to common limited partners ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended September 30, 2013 and 2012, net loss attributable to common limited partners ownership interest is not allocated to approximately 835,000 and 898,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity. For the nine months ended September 30, 2013 and 2012, net loss attributable to common limited partners ownership interest is not allocated to approximately 918,000 and 575,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

Diluted net income (loss) attributable to common limited partners per unit is calculated by dividing net income (loss) attributable to common limited partners, 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, convertible preferred units and warrants, as calculated by the treasury stock method. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of the Partnership s long-term incentive plan (see Note 14).

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Weighted average number of common limited partner units basic	59,440	35,068	50,197	31,865
Add effect of dilutive incentive awards[1]				
Add effect of dilutive convertible preferred limited partner units[2]				
Weighted average number of common limited partner units diluted	59,440	35,068	50,197	31,865

(1) For the three months ended September 30, 2013 and 2012, approximately 835,000 units and 898,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the nine months ended September 30, 2013 and 2012, approximately 918,000 units and 575,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

(2) For the three and nine months ended September 30, 2013 and 2012, potential common limited partner units issuable upon (a) conversion of the Partnership s Class B and Class C preferred units and (b) exercise of the warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

Revenue Recognition

Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership contracts with the Drilling Partnerships to drill partnership wells. The contracts require that the Drilling Partnerships 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 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 statements of operations.

The Partnership generally sells natural gas, crude oil and NGLs at prevailing market prices. Typically, 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 two 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 for further description). The Partnership had unbilled revenues at September 30, 2013 and December 31, 2012 of $54.1 million and $33.4 million, respectively, which were included in accounts receivable within the Partnership s consolidated balance sheets.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, 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) on the Partnership s consolidated financial statements, and at September 30, 2013, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8).

Recently Adopted Accounting Standards

In July 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2013-10, Inclusion of the Fed Funds Effective Swap Rate (or Overnight Index Swap Rate) as a Benchmark Interest Rate for Hedge Accounting Purposes (Update 2013-10), which amends Accounting Standards Codification Topic 815. Topic 815 provides guidance on the risks that are permitted to be hedged in a fair value or cash flow hedge. In addition, only the interest rates on direct Treasury obligations of the U.S. Government (UST) and the London Interbank Offered Rate (LIBOR) swap rate are considered benchmark interest rates. Update 2013-10 amends Topic 815 to include the Overnight Index Swap Rate (OIS), also referred to as the Fed Funds Effective Swap Rate, as a U.S. benchmark interest rate for hedge accounting purposes. Including the OIS as an acceptable U.S. benchmark interest rate in addition to UST and LIBOR will provide risk managers with a more comprehensive spectrum of interest rate resets to utilize as the designated benchmark interest rate risk component under the hedge accounting guidance in Topic 815. Update 2013-10 is effective for qualifying new or redesignated hedging relationships entered into on or after July 17, 2013. The Partnership adopted the requirements of Update 2013-10 upon its effective date of July 17, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220) (Update 2013-02). Update 2013-02 requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present significant amounts reclassified out of accumulated other comprehensive income if the amount reclassified to net income in its entirety is in the same reporting period as incurred. For other amounts that are not required to be reclassified in their entirety to net income, an entity is required to reference to other disclosures that provide additional detail about those amounts. Entities are required to implement the amendments prospectively for reporting periods beginning after December 15, 2012, with early adoption being permitted. The Partnership adopted the requirements of Update 2013-02 upon its effective date of January 1, 2013, and it had no material impact on its financial position, results of operations or related disclosures.

Recently Issued Accounting Standards

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists (Update 2013-11), which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption is permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The Partnership will apply the requirements of Update 2013-11 upon its effective date of January 1, 2014, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (Update 2013-04). Update 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements, for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations and settled litigation and judicial rulings. Update 2013-04 requires an entity to measure joint and several liability arrangements, for which the total amount of the obligation is fixed at the reporting date as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, Update 2013-04 provides disclosure guidance on the nature and amount of the obligation as well as other information. Update 2013-04 is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. The Partnership will apply the requirements of Update 2013-04 upon its effective date of January 1, 2014, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

NOTE 3 ACQUISITIONS

EP Energy Acquisition

On July 31, 2013, the Partnership completed an acquisition of assets from EP Energy E&P Company, L.P. (EP Energy). Pursuant to the purchase and sale agreement, the Partnership acquired certain assets from EP Energy for approximately $705.9 million in cash, net of purchase price adjustments (the EP Energy Acquisition). The purchase price was funded through borrowings under the Partnership s revolving credit facility, the issuance of the Partnership s 9.25% Senior Notes due August 15, 2021 (see Note 7), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 12). The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013. The accompanying consolidated financial statements reflect the operating results of the acquired business commencing July 31, 2013.

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:	
Property, plant and equipment	$ 720,118
Liabilities:	
Asset retirement obligation	14,142
Net assets acquired	$ 705,976

Revenues and net loss of $25.8 million and $4.8 million, respectively, have been included in the Partnership s consolidated statements of operations related to the EP Energy Acquisition for the three and nine months ended September 30, 2013.

DTE Acquisition

On December 20, 2012, the Partnership completed the acquisition of DTE Gas Resources, LLC from DTE Energy Company (NYSE: DTE; DTE) for $257.4 million, subject to certain post-closing adjustments (the DTE Acquisition). In connection with entering into a purchase agreement related to the DTE Acquisition, the Partnership issued approximately 7.9 million of its common limited partner units through a public offering in November 2012 for $174.5 million, which was used to partially repay amounts outstanding under its revolving credit facility prior to closing (see Note 12). The cash paid at closing was funded through $179.8 million of borrowings under the Partnership s revolving credit facility and $77.6 million through borrowings under its term loan credit facility (see Note 7).

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). 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:	
Accounts receivable	$ 10,721
Prepaid expenses and other	2,100
Total current assets	12,821
Property, plant and equipment	263,194
Other assets, net	273
Total assets acquired	$ 276,288
Liabilities:	
Accounts payable	$ 7,760
Accrued liabilities	2,910
Total current liabilities	10,670
Asset retirement obligation and other	8,169
Total liabilities assumed	18,839
Net assets acquired	$ 257,449

Titan Acquisition

On July 25, 2012, the Partnership completed the acquisition of Titan Operating, L.L.C. (Titan) in exchange for 3.8 million common units and 3.8 million newly-created convertible Class B preferred units (which had an estimated collective value of $193.2 million, based upon the closing price of the Partnership s publicly traded units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Note 12). The cash paid at closing was funded through borrowings under the Partnership s credit facility. The common units and preferred units were issued and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act of 1933, as amended (the Securities Act) (see Note 12).

The Partnership accounted for 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).

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

Assets:	
Cash and cash equivalents	$ 372
Accounts receivable	5,253
Prepaid expenses and other	131
Total current assets	5,756
Property, plant and equipment	208,491
Other assets, net	2,344
Total assets acquired	$ 216,591
Liabilities:	
Accounts payable	$ 676
Revenue distribution payable	3,091
Accrued liabilities	1,816
Total current liabilities	5,583
Asset retirement obligation and other	2,418
Total liabilities assumed	8,001
Net assets acquired	$ 208,590

Carrizo Acquisition

On April 30, 2012, the Partnership completed the acquisition of certain oil and natural gas assets from Carrizo Oil and Gas, Inc. (NASDAQ: CRZO; Carrizo) for approximately $187.0 million in cash. The purchase price was funded through borrowings under the Partnership s credit facility and $119.5 million of net proceeds from the sale of 6.0 million of its common units at a negotiated purchase price per unit of $20.00, of which $5.0 million was purchased by certain executives of the Partnership. The common units were issued in a private transaction exempt from registration under Section 4(2) of the Securities Act (see Note 12).

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9).

The following table presents the 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:	
Property, plant and equipment	$ 190,946
Liabilities:	
Asset retirement obligation	3,903
Net assets acquired	$ 187,043

Pro Forma Financial Information

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 EP Energy Acquisition, including the related borrowings, net proceeds from the issuance of debt and issuances of preferred units had occurred on January 1, 2012. 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 EP Acquisition and related offerings had occurred on January 1, 2012 or the results that will be attained in future periods (in thousands, except per share data; unaudited):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Total revenues and other	$ 104,010	$ 107,225	$ 377,085	$ 274,010
Net loss	(18,784)	(12,449)	(13,988)	(84,848)
Net loss attributable to common limited partners	(24,249)	(15,271)	(28,990)	(80,320)
Net loss attributable to common limited partners per unit:				
Basic and Diluted	$ (0.41)	$ (0.26)	$ (0.49)	$ (1.36)

Other Acquisition

On September 20, 2013, the Partnership completed the acquisition of certain assets from Norwood Natural Resources (Norwood) for $5.4 million (the Norwood Acquisition). The assets acquired included Norwood s non-operating working interest in certain producing wells in the Barnett Shale. The Norwood Acquisition had an effective date of June 1, 2013.

NOTE 4 PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2013	December 31, 2012	Estimated Useful Lives

			in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 291,333	$ 244,476	
Pre-development costs	4,328	1,935	
Wells and related equipment	2,135,844	1,222,475	
Total proved properties	2,431,505	1,468,886	
Unproved properties	266,827	292,053	
Support equipment	17,291	13,110	
Total natural gas and oil properties	2,715,623	1,774,049	
Pipelines, processing and compression facilities	42,612	33,092	2 40
Rights of way	267	784	20 40
Land, buildings and improvements	9,207	8,283	3 40
Other	12,919	9,762	3 10
	2,780,628	1,825,970	
Less accumulated depreciation, depletion and amortization	(604,874)	(523,742)	
	$ 2,175,754	$ 1,302,228	

During the three and nine months ended September 30, 2013, the Partnership recognized $0.7 million and $2.0 million, respectively, of loss on asset disposal, pertaining to its decision not to drill wells on leasehold property that expired during the three and nine months ended September 30, 2013 in Indiana and Tennessee.

During the nine months ended September 30, 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 not to achieve due to the then 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 year ended December 31, 2012.

During the year ended December 31, 2012, the Partnership recognized $9.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of gas and oil properties being in excess of the Partnership s estimate of their fair values at December 31, 2012. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

NOTE 5 OTHER ASSETS

The following is a summary of other assets at the dates indicated (in thousands):

	September 30, 2013	December 31, 2012
Deferred financing costs, net of accumulated amortization of $10,996 and $2,388 at September 30, 2013 and December 31, 2012, respectively	$ 35,289	$ 14,467
Notes receivable	4,127	
Other	4,052	1,655
	$ 43,468	$ 16,122

Deferred financing costs are recorded at cost and amortized over the term of the respective debt agreements (see Note 7). Amortization expense of deferred financing costs was $2.8 million and $0.5 million for the three months ended September 30, 2013 and 2012, respectively, and $5.4 million and $1.0 million for the nine months ended September 30, 2013 and 2012, respectively, which was recorded within interest expense on the Partnership s consolidated statements of operations. During the three and nine months ended September 30, 2013, the Partnership capitalized $21.3 million of deferred financing costs related to the amended revolving credit facility and the 9.25% Senior Notes due August 15, 2021 into other assets, net on the Partnership s consolidated balance sheet as a result of the EP Energy Acquisition (see Note 3). During the nine months ended September 30, 2013, the Partnership also recognized $3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of senior unsecured notes due 2021 (7.75% Senior Notes) (see Note 7). There was no accelerated amortization of deferred financing costs during the three months ended September 30, 2013 and 2012 and during the nine months ended September 30, 2012.

At September 30, 2013, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership s consolidated balance sheet. The notes have a maturity date of March 31, 2022, and a 2.25% per annum interest rate. The maturity date of the notes can be extended to March 31, 2027, subject to certain conditions, including an extension fee of 1.0% of the outstanding principal balance. For the three and nine months ended September 30, 2013, approximately $25,000 and $50,000, respectively, of interest income was recognized within other, net on the Partnership s consolidated statements of operations. There was no interest income recognized for the three and nine months ended September 30, 2012. At September 30, 2013, the Partnership recorded no allowance for credit losses within its consolidated balance sheet based upon payment history and ongoing credit evaluations.

NOTE 6 ASSET RETIREMENT OBLIGATIONS

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

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

The Partnership proportionately consolidates its ownership interest of the asset retirement obligations of its Drilling Partnerships. At September 30, 2013, the Drilling Partnerships had $62.3 million of aggregate asset retirement obligation liabilities recognized on their combined balance sheets allocable to the limited partners, exclusive of the Partnership s proportional interest in such liabilities. Under the terms of the respective partnership agreements, the Partnership maintains the right to retain a portion or all of the distributions to the limited partners of its Drilling Partnerships to cover the limited partners share of the plugging and abandonment costs up to a specified amount per month. During the three and nine months ended September 30, 2013, the Partnership withheld $0.1 million and $0.2 million, respectively, of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. No amounts were withheld during the three and nine months ended September 30, 2012. The Partnership s historical practice and continued intention is to retain distributions from the limited partners as the wells within each Drilling Partnership near the end of their useful life. On a partnership-by-partnership basis, the Partnership assesses its right to withhold amounts related to plugging and abandonment costs based on several factors including commodity price trends, the natural decline in the production of the wells, and current and future costs. Generally, the Partnership s intention is to retain distributions from the limited partners as the fair value of the future cash flows of the limited partners interest approaches the fair value of the future plugging and abandonment cost. Upon the Partnership s decision to retain all future distributions to the limited partners of its Drilling Partnerships, the Partnership will assume the related asset retirement obligations of the limited partners.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Asset retirement obligations, beginning of period	$ 67,732	$ 51,046	$ 64,794	$ 45,779
Liabilities incurred	14,699	2,424	15,943	6,516
Liabilities settled	(158)	(198)	(381)	(448)
Accretion expense	1,294	768	3,211	2,193
Asset retirement obligations, end of period	$ 83,567	$ 54,040	$ 83,567	$ 54,040

The above accretion expense was included in depreciation, depletion and amortization in the Partnership s consolidated statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations and other in the Partnership s consolidated balance sheets. During the three and nine months ended

September 30, 2013, the Partnership incurred $14.1 million of future plugging and abandonment costs related to the EP Energy Acquisition it consummated during the period. During the three and nine months ended September 30, 2012, the Partnership incurred $2.0 million and $5.9 million, respectively, of future plugging and abandonment costs related to other acquisitions it consummated during those respective periods.

NOTE 7 DEBT

Total debt consists of the following at the dates indicated (in thousands):

		September 30, 2013		December 31, 2012	
Revolving credit facility	$	425,000	$	276,000	
Term loan credit facility				75,425	
7.75 % Senior Notes due 2021		275,000			
9.25 % Senior Notes due 2021		248,279			
Total debt		948,279		351,425	
Less current maturities					
Total long-term debt	$	948,279	$	351,425	

Credit Facility

On July 31, 2013, in connection with the acquisition of assets from EP Energy (see Note 3), the Partnership entered into a second amended and restated credit agreement (Credit Agreement) with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amended and restated the Partnership s existing revolving credit facility. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of $835.0 million and a maximum facility amount of $1.5 billion, which is scheduled to mature in July 2018. At September 30, 2013, $425.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $2.1 million was outstanding at September 30, 2013. 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 certain of the Partnership s material subsidiaries, and any subsidiaries of the Partnership, other than subsidiary guarantors, are minor. Borrowings under the credit facility bear interest, at the Partnership s election, at either LIBOR plus an applicable margin between 1.75% and 2.75% 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 0.75% and 1.75% per annum. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.5% per annum if 50% or more of the borrowing base is utilized and 0.375% per annum if less than 50% of the borrowing base is utilized, which is included within interest expense on the Partnership s consolidated statements of operations. At September 30, 2013, the weighted average interest rate on outstanding borrowings under the credit facility was 2.2%.

The Credit Agreement contains customary covenants that limit the Partnership s ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of September 30, 2013. 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 4.50 to 1.0 as of the last day of the quarter ended September 30, 2013, 4.25 to 1.0 as of the last day of the quarters ended December 31, 2013 and March 31, 2014 and 4.0 to 1.0 as of the last day of fiscal quarters ending thereafter and 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. Based on the definitions contained in the Partnership s Credit Agreement, at September 30, 2013, the Partnership s ratio of current assets to current liabilities was 2.7 to 1.0, and its ratio of Total Funded Debt to EBITDA was 4.2 to 1.0.

Senior Notes

On July 30, 2013, the Partnership issued $250.0 million of its 9.25% Senior Notes due 2021 (9.25% Senior Notes) in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million, net of underwriting fees and other offering costs of $5.5 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Note 3). The 9.25% Senior Notes were presented net of a $1.7 million unamortized discount as of September 30, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date being February 15, 2014. At any time on or after August 15, 2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, the Partnership may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the 9.25% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the SEC) to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 30, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If the Partnership fails to comply with its obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

On January 23, 2013, the Partnership issued $275.0 million of its 7.75% Senior Notes due 2021 in a private placement transaction at par. The Partnership used the net proceeds of approximately $267.7 million, net of underwriting fees and other offering costs of $7.3 million, to repay all of the indebtedness and accrued interest outstanding under its then-existing term loan credit facility and a portion of the amounts outstanding under its revolving credit facility. In connection with the retirement of the Partnership s term loan credit facility and the reduction in its revolving credit facility borrowing base, the Partnership accelerated $3.2 million of amortization expense related to deferred financing costs during the nine months ended September 30, 2013 (see Note 5). Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

In connection with the issuance of the 7.75% Senior Notes, the Partnership entered into registration rights agreements, whereby it agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by January 23, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 7.75% Senior Notes. If the Partnership fails to comply with its obligations to register the 7.75% Senior Notes within the specified time periods, the 7.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable. On July 1, 2013, the Partnership filed a registration statement relating to the exchange offer for the 7.75% Senior Notes.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of the Partnership s material subsidiaries. As of September 30, 2013, the Partnership was a holding company and had no independent assets or operations of its own. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, and any subsidiaries of the Partnership, other than the subsidiary guarantors, are minor. There are no restrictions on the Partnership s ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% and 9.25% Senior Notes contain covenants, including limitations of the Partnership s ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of the Partnership s assets. The Partnership was in compliance with these covenants as of September 30, 2013.

Cash payments for interest by the Partnership were $15.2 million and $2.0 million for the nine months ended September 30, 2013 and 2012, respectively.

NOTE 8 DERIVATIVE INSTRUMENTS

The Partnership uses a number of different derivative instruments, principally swaps, collars and options, in connection with its 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 are determined by management of the Partnership through the utilization of market data, will be recognized immediately within other, net in the Partnership s consolidated 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 statements of operations as the underlying transactions are settled. For non-qualifying derivatives and for the ineffective portion of qualifying derivatives, management recognizes changes in fair value within other, net in the Partnership s consolidated 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 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 balance sheets as the initial value of the options. The Partnership reflected net derivative assets on its consolidated balance sheets of $47.7 million and $20.3 million at September 30, 2013 and December 31, 2012, respectively. Of the $50.2 million of net gain in accumulated other comprehensive income on the Partnership s consolidated balance sheet at September 30, 2013, if the fair values of the instruments remain at current market values, the Partnership will reclassify $18.7 million of gains to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $31.5 million of gas and oil production revenues will be reclassified to the Partnership s consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future commodity price changes. Approximately $1.3 million and $0.8 million of derivative gains were reclassified from other comprehensive income related to derivative instruments entered into during the three and nine months ended September 30, 2013, respectively.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Gain reclassified from accumulated other comprehensive income:				
Gas and oil production revenue	$ (1,145)	$ (6,114)	$ (4,424)	$ (15,453)
Total	$ (1,145)	$ (6,114)	$ (4,424)	$ (15,453)

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 balance sheets for the periods indicated (in thousands):

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount Assets of Presented in the Consolidated Balance Sheets
As of September 30, 2013			
Current portion of derivative assets	$ 23,643	$ (4,169)	$ 19,474
Long-term portion of derivative assets	32,060	(3,560)	28,500
Current portion of derivative liabilities	254	(254)	
Total derivative assets	$ 55,957	$ (7,983)	$ 47,974
As of December 31, 2012			
Current portion of derivative assets	$ 14,248	$ (1,974)	$ 12,274
Long-term portion of derivative assets	14,724	(5,826)	8,898
Long-term portion of derivative liabilities	800	(800)	
Total derivative assets	$ 29,772	$ (8,600)	$ 21,172

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Liabilities Presented in the Consolidated Balance Sheets
As of September 30, 2013			
Current portion of derivative assets	$ (4,169)	$ 4,169	$
Long-term portion of derivative assets	(3,560)	3,560	
Current portion of derivative liabilities	(572)	254	(318)
Long-term portion of derivative liabilities			
Total derivative liabilities	$ (8,301)	$ 7,983	$ (318)
As of December 31, 2012			
Current portion of derivative assets	$ (1,974)	$ 1,974	$
Long-term portion of derivative assets	(5,826)	5,826	
Long-term portion of derivative liabilities	(1,688)	800	(888)
Total derivative liabilities	$ (9,488)	$ 8,600	$ (888)

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. NGL fixed price swaps are priced based on a WTI crude oil index. These contracts have qualified and been designated as cash flow hedges and were recorded at their fair values.

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.

During the nine months ended September 30, 2013, the Partnership entered into contracts which provided the option to enter into swap contracts for future production periods (swaptions) up through September 30, 2013 for production volumes related to assets acquired from EP Energy (see Note 3). In connection with the swaption contracts, the Partnership paid premiums of $14.5 million, which represented their fair value on the date the transactions were initiated and was initially recorded as derivative assets on the Partnership s consolidated balance sheet and was fully amortized as of September 30, 2013. Swaption premiums paid are amortized over the period from initiation of the contract through termination date. For the three and nine months ended September 30, 2013, the Partnership recognized $13.2 million and $14.5 million, respectively, of amortization expense in other, net on the Partnership s consolidated statement of operations related to the swaption contracts.

During the nine months ended September 30, 2012, the Partnership entered into swaptions contracts up through May 31, 2012 for production volumes related to wells acquired from Carrizo (see Note 3). In connection with the swaption contracts, the Partnership paid premiums of $4.6 million, which represented their fair value on the date the transactions were initiated and was initially recorded as a derivative asset on the Partnership s consolidated balance sheet and was fully amortized as of September 30, 2012. For the nine months ended September 30, 2012, the Partnership recorded approximately $4.6 million of amortization expense in other, net on the Partnership s consolidated statements of operations related to the swaption contracts. No amortization expense was recorded on the Partnership s consolidated statement of operations for the three months ended September 30, 2012.

The Partnership recognized gains of $1.1 million and $6.1 million for the three months ended September 30, 2013 and 2012, respectively, and $4.4 million and $15.5 million for the nine months ended September 30, 2013 and 2012, respectively, on settled contracts covering commodity production. These gains were included within gas and oil production revenue in the Partnership s consolidated statements of operations. As the underlying prices and terms in the Partnership s derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three and nine months ended September 30, 2013 and 2012 for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At September 30, 2013, 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)
2013	15,597,400	$ 3.909	$ 4,881
2014	60,153,000	$ 4.152	17,536
2015	50,274,500	$ 4.240	9,113
2016	43,946,300	$ 4.318	6,556
2017	24,840,000	$ 4.532	5,501
2018	3,960,000	$ 4.716	1,030

$	44,617

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)	
2013	Puts purchased	1,380,000	$	4.395	$	1,134
2013	Calls sold	1,380,000	$	5.443		(2)
2014	Puts purchased	3,840,000	$	4.221		2,257
2014	Calls sold	3,840,000	$	5.120		(284)
2015	Puts purchased	3,480,000	$	4.234		2,059
2015	Calls sold	3,480,000	$	5.129		(655)
					$	4,509

Natural Gas Put Options   Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)[1]	Average Fixed Price (per MMBtu)[1]	Fair Value Asset (in thousands)[2]
2013	Puts purchased	540,000	$ 3.450	$ 25
2014	Puts purchased	1,800,000	$ 3.800	541
2015	Puts purchased	1,440,000	$ 4.000	608
2016	Puts purchased	1,440,000	$ 4.150	762
				$ 1,936

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Asset/(Liability) (in thousands)[3]
2013	36,000	$ 93.656	$ (327)
2014	105,000	$ 91.571	(389)
2015	96,000	$ 88.550	
2016	84,000	$ 85.651	68
2017	60,000	$ 83.780	45
			$ (603)

Natural Gas Liquids Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Asset (in thousands)[4]
2014	2,520,000	$ 0.303	100
			$ 100

Natural Gas Liquids Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset/(Liability) (in thousands)(5)
2013	3,864,000	1.084	4
2014	11,592,000	$ 0.996	(11)
			$ (7)

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Asset/(Liability) (in thousands)(3)
2013	170,200	$ 93.738	$ (1,530)
2014	552,000	$ 92.668	(1,515)
2015	567,000	$ 88.144	(211)
2016	225,000	$ 85.523	155
2017	132,000	$ 83.305	39
			$ (3,062)

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]
2013	Puts purchased	20,000	$	90.000	$	12
2013	Calls sold	20,000	$	116.396		(5)
2014	Puts purchased	41,160	$	84.169		132
2014	Calls sold	41,160	$	113.308		(76)
2015	Puts purchased	29,250	$	83.846		181
2015	Calls sold	29,250	$	110.654		(78)
					$	166
				Total net assets	$	47,656

[1] MMBtu represents million British Thermal Units; Bbl represents barrels; Gal represents gallons.
[2] Fair value based on forward NYMEX natural gas prices, as applicable.
[3] Fair value based on forward WTI crude oil prices, as applicable.
[4] Fair value based on forward Mt. Belvieu ethane prices, as applicable.
[5] Fair value based on forward Mt. Belvieu propane prices, as applicable.

At September 30, 2013, the Partnership had net cash proceeds of $5.9 million related to hedging positions monetized on behalf of the Drilling Partnerships limited partners, which were included within cash and cash equivalents on the Partnership s consolidated balance sheet. 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 balance sheets as of September 30, 2013 and December 31, 2012.

In June 2012, the Partnership entered into natural gas put option contracts, which related to future natural gas production of the Drilling Partnerships. Therefore, a portion of any unrealized derivative gain or loss is allocable to the limited partners of the Drilling Partnerships based on their share of estimated gas production related to the derivatives not yet settled. At September 30, 2013, net unrealized derivative assets of $1.9 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At September 30, 2013, the Partnership had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under its revolving credit facility (see Note 7), the Partnership is required to utilize this secured hedge facility for future commodity risk management activity for its equity production volumes within the participating Drilling Partnerships. Each participating Drilling Partnership s obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets and by a guarantee of the general partner of the Drilling Partnership. The Partnership, as general partner of the Drilling Partnerships, administers 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 commodity indices quoted prices for futures and options contracts traded on open markets 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 September 30, 2013 and December 31, 2012 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
As of September 30, 2013				
Derivative assets, gross				
Commodity swaps	$	$ 48,248	$	$ 48,248
Commodity puts		1,936		1,936
Commodity options		5,773		5,773
Commodity swaptions				
Total derivative assets, gross		55,957		55,957
Derivative liabilities, gross				
Commodity swaps		(7,202)		(7,202)
Commodity puts				
Commodity options		(1,099)		(1,099)
Total derivative liabilities, gross		(8,301)		(8,301)

	Level 1	Level 2	Level 3	Total
Total derivatives, fair value, net	$	$ 47,656	$	$ 47,656

	Level 1	Level 2	Level 3	Total
As of December 31, 2012				
Derivative assets, gross				
Commodity swaps	$	$ 15,859	$	$ 15,859
Commodity puts		2,991		2,991
Commodity options		10,923		10,923
Total derivative assets, gross		29,773		29,773
Derivative liabilities, gross				
Commodity swaps		(6,813)		(6,813)
Commodity puts				
Commodity options		(2,676)		(2,676)
Total derivative liabilities, gross		(9,489)		(9,489)
Total derivatives, fair value, net	$	$ 20,284	$	$ 20,284

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 balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of the Partnership s long-term debt at September 30, 2013, which consists of its Senior Notes and outstanding borrowings under its revolving credit facility (see Note 7), was $936.2 million compared with the carrying amount of $948.3 million. At September 30, 2013 and December 31, 2012, the carrying value of outstanding borrowings under the Partnership s revolving credit facility (see Note 7), which bears interest at variable interest rates, approximated its estimated fair value. The estimated fair values of the Partnership s Senior Notes were based upon the market approach and calculated using yields of the Partnership as provided by financial institutions and thus was categorized as a Level 3 value.

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

Management estimates the fair value of its asset retirement obligations based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors at the date of establishment of an asset retirement obligation such as: amounts and timing of settlements, the credit-adjusted risk-free rate of the Partnership and estimated inflation rates.

Information for assets and liabilities that were measured at fair value on a nonrecurring basis for the three and nine months ended September 30, 2013 and 2012 were as follows (in thousands):

	Three Months Ended September 30,			
	2013		2012	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$ 14,699	$ 14,699	$ 2,424	$ 2,424
Total	$ 14,699	$ 14,699	$ 2,424	$ 2,424

	Nine Months Ended September 30,			
	2013		2012	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$ 15,943	$ 15,943	$ 6,516	$ 6,516
Total	$ 15,943	$ 15,943	$ 6,516	$ 6,516

During the three and nine months ended September 2013, the Partnership completed the acquisitions of certain oil and gas assets from EP Energy (see Note 3). During the nine months ended September 30, 2012, the Partnership completed the acquisitions of certain oil and gas assets from Carrizo and certain proved reserves and associated assets from Titan (see Note 3). 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. The fair value of the warrants associated with the Class C preferred units (see Note 12) was measured using a Black-Scholes pricing model which is based on Level 3 inputs including conversion price of $23.10, discount rate of 0.21% and estimated volatility rate of 35%.

NOTE 10 CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with Drilling 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 of the Drilling Partnerships if it breaches its responsibilities with respect to the operations of the Drilling Partnerships. The Partnership is entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership s revenue and costs and expenses according to the respective partnership agreements.

Relationship with Atlas Pipeline Partners, L.P. The Partnership s general partner, ATLS, also maintains a general partner ownership interest in Atlas Pipeline Partners, L.P. (APL), a publicly traded Delaware master limited partnership (NYSE: APL) and midstream energy service provider engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States. In the Chattanooga Shale, a portion of the natural gas produced by the Partnership is gathered and processed by APL. For the three month periods ended September 30, 2013 and 2012, $0.1 million and $0.2 million, respectively, of gathering fees were paid by the Partnership to APL. For the nine months ended September 30, 2013 and 2012, $0.2 million and $0.4 million, respectively, of gathering fees were paid by the Partnership to APL, respectively.

In addition, in Lycoming County, Pennsylvania, APL has agreed to provide assistance in the design and construction management services for the Partnership with respect to a pipeline. The total estimated price for the project is under $2.5 million, of which $1.6 million had been reimbursed to APL as of September 30, 2013.

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, as of September 30, 2013, the management of the Partnership believes that any such liability incurred would not be material. Also, the Partnership has agreed to subordinate a portion of its share of net partnership revenues from the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% per year determined on a cumulative basis, over a specific period, typically the first five to seven years, in accordance with the terms of the partnership agreements. For the three months ended September 30, 2013 and 2012, $2.2 million and $1.8 million, respectively, and $6.5 million and $3.6 million for the nine months ended September 30, 2013 and 2012, respectively, of the Partnership s revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships.

Certain of the Partnership s executives are parties to employment agreements with ATLS that provide compensation and certain other benefits. The agreements also provide for severance payments under certain circumstances.

As of September 30, 2013, the Partnership is committed to expend approximately $67.7 million, principally on drilling and completion expenditures and throughput commitments.

Legal Proceedings

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

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

In early September 2013, Atlas Energy Tennessee, LLC, was dismissed as a party on jurisdictional grounds.

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

NOTE 12 ISSUANCES OF UNITS

Equity Offerings

In July 2013, in connection with the closing of the EP Energy Acquisition (see Note 3), the Partnership issued 3,749,986 of its newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of $23.10, for proceeds of $86.6 million. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) $0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The initial Class C preferred distribution was paid for the quarter ending September 30, 2013. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C Preferred Units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, ATLS, as purchaser of the Class C preferred units, received 562,497 warrants to purchase the Partnership s common units at an exercise price equal to the face value of the Class C preferred units. The warrants were exercisable beginning October 29, 2013 into an equal number of common units of the Partnership at an exercise price of $23.10 per unit, subject to adjustments provided therein. The warrants will expire on July 31, 2016. ATLS was granted certain registration rights with respect to the common units underlying the Class C preferred units and the common units issuable upon exercise of the warrants.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, the Partnership entered into a registration rights agreement pursuant to which it agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. The Partnership agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants.

In June 2013, in connection with entering the EP Energy Acquisition, the Partnership sold an aggregate of 14,950,000 of its common limited partner units (including a 1,950,000 over-allotment) in a public offering at a price of $21.75 per unit, yielding net proceeds of approximately $313.1 million. The Partnership utilized the net proceeds from the sale to repay the outstanding balance under its revolving credit facility (see Note 7).

In May 2013, the Partnership entered into an equity distribution program with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution program, the Partnership may sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. Sales of common limited partner units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made directly on the New York Stock Exchange, the existing trading market for the common limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. The Partnership will pay each of the agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common limited partner units sold through such agent. During the nine months ended September 30, 2013, the Partnership issued 309,174 common limited partner units under the equity distribution program for net proceeds of $7.0 million, net of $0.4 million in commissions paid. No common limited partner units were issued under the equity distribution program during the three months ended September 30, 2013. The Partnership utilized the net proceeds from the sale to repay borrowings outstanding under its revolving credit facility.

In November and December 2012, in connection with entering into a purchase agreement to acquire certain producing wells and net acreage from DTE, the Partnership sold an aggregate of 7,898,210 of its common limited partner units in a public offering at a price of $23.01 per unit, yielding net proceeds of approximately $174.5 million. The Partnership utilized the net proceeds from the sale to repay a portion of the outstanding balance under its revolving credit facility and $2.2 million under its term loan credit facility.

In July 2012, the Partnership completed the acquisition of certain proved reserves and associated assets in the Barnett Shale from Titan in exchange for 3.8 million Partnership common units and 3.8 million newly-created convertible Class B preferred units (which have an estimated collective value of $193.2 million, based upon the closing price of the Partnership s publicly traded common units as of the acquisition closing date), as well as $15.4 million in cash for closing adjustments (see Note 3). The preferred units are voluntarily convertible to common units on a one-for-one basis within three years of the acquisition closing date at a strike price of $26.03 plus all unpaid preferred distributions per unit, and will be mandatorily converted to common units on the third anniversary of the issuance. While outstanding, the preferred units will receive regular quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

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

In April 2012, the Partnership completed the acquisition of certain oil and gas assets from Carrizo (see Note 3). 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 net proceeds of $119.5 million, of which $5.0 million was purchased by certain executives of the Partnership. The common units issued by the Partnership are subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that the Partnership would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, the Partnership filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of one of the requirements of the registration rights agreement noted previously. On August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS general partner approved the distribution of approximately 5.24 million Partnership common units which were distributed on March 13, 2012 to ATLS unitholders using a ratio of 0.1021 Partnership 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.

Distributions declared by the Partnership from its formation through September 30, 2013 were as follows (in thousands, except per unit amounts):

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 Preferred Limited Partners	Total Cash Distribution to the General Partner s Class A Units
May 15, 2012	March 31, 2012	$ 0.12(1)	$ 3,144	$	$ 64
August 14, 2012	June 30, 2012	$ 0.40	$ 12,891	$	$ 263
November 14, 2012	September 30, 2012	$ 0.43	$ 15,510	$ 1,652	$ 350
February 14, 2013	December 31, 2012	$ 0.48	$ 21,107	$ 1,841	$ 618
May 15, 2013	March 31, 2013	$ 0.51	$ 22,428	$ 1,957	$ 946
August 14, 2013	June 30, 2013	$ 0.54	$ 32,097	$ 2,072	$ 1,884

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

On October 24, 2013, the Partnership declared a cash distribution of $0.56 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2013. The $40.0 million distribution, including $2.4 million and $4.2 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2013 to unitholders of record at the close of business on November 6, 2013.

NOTE 14   BENEFIT PLAN

2012 Long-Term Incentive Plan

The Partnership s 2012 Long-Term Incentive Plan (2012 LTIP), effective March 2012, provides incentive awards to officers, employees and directors and employees of the general partner and its affiliates, consultants and joint venture partners (collectively, the Participants), who perform services for the Partnership. The 2012 LTIP is administered by the board of the general partner, a committee of the board or the board (or committee of the board) of an affiliate (the LTIP Committee). Under the 2012 LTIP, the LTIP Committee may grant awards of phantom units, restricted units or unit options for an aggregate of 2,900,000 common limited partner units. At September 30, 2013, the Partnership had 2,338,500 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 350,668 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, following a change in control, 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), 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. Phantom units granted under the 2012 LTIP generally will vest 25% of the original granted amount on each of the next four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at September 30, 2013, 279,387 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at September 30, 2013 include DERs. During the three and nine months ended September 30, 2013, the

Partnership paid $0.5 million and $1.5 million, respectively, with respect to the 2012 LTIP s DERs. During the three and nine months ended September 30, 2012, respectively, the Partnership paid $0.3 million with respect to DERs. These amounts were recorded as reductions of partners capital on the Partnership s consolidated balance sheet.

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

	Three Months Ended September 30,			
	2013		2012	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of period	845,932	$ 24.51	810,476	$ 24.69
Granted	37,191	21.86	129,500	25.23
Vested and issued [1]	(33,123)	24.72		
Forfeited			(1,000)	24.67
Outstanding, end of period[2][3]	850,000	$ 24.38	938,976	$ 24.76
Vested and not yet issued [4]	7,749	$ 25.51		$
Non-cash compensation expense recognized (in thousands)		$ 2,045		$ 2,915

	Nine Months Ended September 30,			
	2013		2012	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year	948,476	$ 24.76		$
Granted	128,981	22.07	939,976	24.76
Vested and issued [1]	(204,582)	24.70		
Forfeited	(22,875)	24.23	(1,000)	24.67
Outstanding, end of period[2][3]	850,000	$ 24.38	938,976	$ 24.76
Vested and not yet issued [4]	7,749	$ 25.51		$
Non-cash compensation expense recognized (in thousands)		$ 7,329		$ 4,655

(1) The intrinsic value of phantom unit awards vested and issued during the three and nine months ended September 30, 2013 was $4.9 million and $4.2 million, respectively. No phantom unit awards vested and were issued during the three and nine months ended September 30, 2012.

(2) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2013 was $17.8 million.

(3) There was approximately $40,000 and $31,000 recognized as liabilities on the Partnership s consolidated balance sheet at September 30, 2013 and December 31, 2012, respectively, representing 7,939 and 3,476 units, respectively, due to the option of the participants to settle in cash instead of units. The respective weighted average grant date fair value for these units was $25.19 and $28.75 at September 30, 2013 and December 31, 2012, respectively.

(4) The intrinsic value of phantom unit awards vested, but not yet issued at September 30, 2013 was $0.2 million. No phantom unit awards had vested, but had not yet been issued at September 30, 2012.

At September 30, 2013, the Partnership had approximately $10.8 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards.

Unit Options

A unit option is the right to purchase a Partnership common unit in the future at a predetermined price (the exercise price). The exercise price of each option is determined by the LTIP Committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The LTIP Committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method by which the exercise price may be paid by the Participant. Unit option awards expire 10 years from the date of grant. 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 372,000 unit options outstanding under the 2012 LTIP at September 30, 2013 that will vest within the following twelve months. No cash was received from the exercise of options for the three and nine months ended September 30, 2013 and 2012.

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

	Three Months Ended September 30,			
	2013		2012	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	1,494,750	$ 24.67	1,499,500	$ 24.67
Granted			18,000	25.18
Exercised [1]				
Forfeited	(6,250)	24.67	(2,000)	24.67
Outstanding, end of period[2][3]	1,488,500	$ 24.67	1,515,500	$ 24.68
Options exercisable, end of period[4]	371,375	$ 24.67		$
Non-cash compensation expense recognized (in thousands)		$ 915		$ 1,927

	Nine Months Ended September 30,			
	2013		2012	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of year	1,515,500	$ 24.68		$
Granted	2,500	22.88	1,517,500	24.68
Exercised [1]				
Forfeited	(29,500)	24.74	(2,000)	24.67
Outstanding, end of period[2][3]	1,488,500	$ 24.67	1,515,500	$ 24.68
Options exercisable, end of period[4]	371,375	$ 24.67		$
Non-cash compensation expense recognized (in thousands)		$ 2,880		$ 3,201

(1) No options were exercised during three and nine months ended September 30, 2013 and 2012.

(2) The weighted average remaining contractual life for outstanding options at September 30, 2013 was 8.6 years.

(3) There was no aggregate intrinsic value of options outstanding at September 30, 2013.

(4) The weighted average remaining contractual life for exercisable options at September 30, 2013 was 8.6 years. There were no aggregate intrinsic values of options exercisable at September 30, 2013 and 2012. No options were exercisable at September 30, 2012.

At September 30, 2013, the Partnership had approximately $3.5 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, which is based on Level 3 inputs, to estimate the weighted average fair value of options granted.

The following weighted average assumptions were used for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Expected dividend yield		2.5%	6.7%	1.5%
Expected unit price volatility		46.0%	35.8%	47.0%
Risk-free interest rate		0.8%	1.1%	1.0%
Expected term (in years)		6.25	6.35	6.25
Fair value of unit options granted	$	$ 8.72	$ 3.63	$ 9.78

Restricted Units

Restricted units are actual common units issued to a participant that are subject to vesting restrictions and evidenced in such manner as the LTIP Committee may deem appropriate, including book-entry registration or issuance of one or more unit certificates. Prior to or upon the grant of an award of restricted units, the LTIP Committee will condition the vesting or transferability of the restricted units upon continued service, the attainment of performance goals or both. A holder of restricted units will have certain rights of holders of common units in general, including the right to vote the restricted units. However, during the period in 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 September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Gas and oil production:				
Revenues	$ 80,332	$ 24,699	$ 173,490	$ 61,323
Operating costs and expenses	(29,419)	(7,295)	(63,670)	(16,247)
Depreciation, depletion and amortization expense	(39,900)	(12,576)	(80,176)	(29,663)
Segment income	$ 11,013	$ 4,828	$ 29,644	$ 15,413
Well construction and completion:				
Revenues	$ 10,964	$ 36,317	$ 92,293	$ 92,277
Operating costs and expenses	(9,534)	(31,581)	(80,255)	(79,882)
Segment income	$ 1,430	$ 4,736	$ 12,038	$ 12,395
Other partnership management:(1)				
Revenues	$ (211)	$ 13,727	$ 20,676	$ 29,289
Operating costs and expenses	(6,781)	(6,790)	(20,776)	(20,261)
Depreciation, depletion and amortization expense	(1,756)	(1,342)	(4,885)	(4,185)
Segment income (loss)	$ (8,748)	$ 5,595	$ (4,985)	$ 4,843
Reconciliation of segment income (loss) to net loss:				
Segment income (loss):				
Gas and oil production	$ 11,013	$ 4,828	$ 29,644	$ 15,413
Well construction and completion	1,430	4,736	12,038	12,395
Other partnership management	(8,748)	5,595	(4,985)	4,843
Total segment income	3,695	15,159	36,697	32,651
General and administrative expenses(2)	(31,983)	(16,147)	(63,767)	(48,427)
Chevron transaction expense(2)		(7,670)		(7,670)
Interest expense(2)	(10,748)	(1,423)	(22,145)	(2,529)
Gain (loss) on asset sales and disposal(2)	(661)	2	(2,035)	(7,019)
Net loss	$ (39,697)	$ (10,079)	$ (51,250)	$ (32,994)
Capital expenditures:				
Gas and oil production	$ 60,483	$ 26,321	$ 176,582	$ 67,582
Other partnership management	6,370	242	9,780	1,260
Corporate and other	7,091	1,164	17,634	4,537
Total capital expenditures	$ 73,944	$ 27,727	$ 203,996	$ 73,379

	September 30, 2013		December 31, 2012	
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	$	2,254,509	$	1,342,403
Well construction and completion		21,066		62,472
Other partnership management		56,058		47,097
Corporate and other		55,219		46,980
	$	2,386,852	$	1,498,952

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

(2) The Partnership notes that gain (loss) on asset sales and disposal, general and administrative expenses, Chevron transaction expense and

interest expense have not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.

NOTE 16 SUBSEQUENT EVENTS

Cash Distribution. On October 24, 2013, the Partnership declared a cash distribution of $0.56 per unit on its outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2013. The $40.0 million distribution, including $2.4 million and $4.2 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2013 to unitholders of record at the close of business on November 6, 2013.

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, 2012. 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, crude oil and natural gas liquids (NGL), 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, crude oil and NGL production activities.

At September 30, 2013, Atlas Energy, L.P. (ATLS), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 36.9% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

We were formed in October 2011 to own and operate substantially all of ATLS exploration and production assets, 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.

FINANCIAL PRESENTATION

Our consolidated balance sheets at September 30, 2013 and December 31, 2012, the consolidated statements of operations for the three months ended September 30, 2013 and 2012, the consolidated statements of operations for the nine months ended September 30, 2013, and the portion of the consolidated statement of operations for the nine months ended September 30, 2012 subsequent to the transfer of assets on March 5, 2012 include our accounts and our wholly-owned subsidiaries. The portion of the consolidated statement of operations for the nine months ended September 30, 2012 prior to the transfer of assets on March 5, 2012 was 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 balance sheets and related consolidated 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. All significant intercompany transactions and balances have been eliminated in the combination of the financial statements.

SUBSEQUENT EVENTS

Cash Distribution. On October 24, 2013, we declared a cash distribution of $0.56 per unit on our outstanding common limited partner units, representing the cash distribution for the quarter ended September 30, 2013. The $40.0 million distribution, including $2.4 million and $4.2 million to the general partner and preferred limited partners, respectively, will be paid on November 14, 2013 to unitholders of record at the close of business on November 6, 2013.

RECENT DEVELOPMENTS

EP Energy Acquisition. On July 31, 2013, we completed the acquisition of assets from EP Energy E&P Company, L.P. (EP Energy), a wholly-owned subsidiary of EP Energy, LLC, and EPE Nominee Corp. Pursuant to the purchase and sale agreement, we acquired certain assets from EP Energy for approximately $705.9 million in cash, net of purchase price adjustments (the EP Energy Acquisition). The purchase price was funded through borrowings under our revolving credit facility, the issuance of our 9.25% Senior Notes due August 15, 2021, the issuance of 14,950,000 common limited partner units, and the issuance of our newly created Class C convertible preferred units. The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013.

Issuance of Preferred Units. In connection with the closing of the EP Energy Acquisition on July 31, 2013, we issued $86.6 million of our newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of $23.10, which was the face value of the units. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) $0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The initial Class C preferred distribution will be paid for the quarter ending September 30, 2013. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C Preferred Units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, ATLS, as purchaser of the Class C preferred units, also received 562,497 warrants to purchase our common units at an exercise price equal to the face value of the Class C preferred units. The warrants are exercisable beginning October 29, 2013 into an equal number of our common units at an exercise price of $23.10 per unit subject to adjustments as provided therein. The warrants will expire on July 31, 2016.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, we entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. We agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants.

Credit Facility Amendment. On July 31, 2013, in connection with the acquisition of assets from EP Energy, we entered into a second amended and restated credit agreement (see Credit Facility).

Senior Notes. On July 30, 2013, we issued $250.0 million of 9.25% Senior Notes due 2021 (9.25% Senior Notes) in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million, net of underwriting fees and other offering costs of $5.5 million. The net proceeds were used to partially fund the EP Acquisition (see Recent Developments). The 9.25% Senior Notes were presented combined with a net $1.7 million unamortized discount as of September 30, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date being February 15, 2014. At any time prior to August 15, 2017, we may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, we may redeem some or all of the 9.25% Senior Notes at the redemption prices of 102.313% and on or after August 15, 2019, We may redeem some or all of the 9.25% Senior

Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, we may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at 109.250%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, we must offer to repurchase the 9.25% Senior Notes (see Senior Notes).

In connection with the issuance of the 9.25% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the SEC) to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated not later than 365 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If we fail to comply with our obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable.

Common Unit Offering. In June 2013, in connection with the EP Energy acquisition, we sold an aggregate of 14,950,000 of our common limited partner units (including a 1,950,000 over-allotment) in a public offering at a price of $21.75 per unit, yielding net proceeds of approximately $313.1 million (see Issuance of Units). We utilized the net proceeds from the sale to repay the outstanding balance under our revolving credit facility (see Credit Facility).

Equity Distribution Program. In May 2013, we entered into an equity distribution program with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution program, we may sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. Sales of common limited partner units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made directly on the New York Stock Exchange, the existing trading market for the common limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common limited partner units sold through such agent. During the nine months ended September 30, 2013, we issued 309,174 common limited partner units under the equity distribution program for net proceeds of $7.0 million, net of $0.4 million in commissions paid. We utilized the net proceeds from the sale to repay borrowings outstanding under our revolving credit facility (see Issuance of Units).

Senior Notes. On January 23, 2013, we issued $275.0 million of 7.75% senior unsecured notes due January 15, 2021 (7.75% Senior Notes) in a private placement transaction at par. During the nine months ended September 30, 2013, we used the net proceeds of approximately $267.7 million, net of underwriting fees and other offering costs of $7.3 million, to repay all of the indebtedness and accrued interest outstanding under our term loan credit facility and a portion of the amounts outstanding under our revolving credit facility (see Credit Facility). In connection with the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated $3.2 million of amortization expense related to deferred financing costs during the nine months ended September 30, 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019. The indenture governing the 7.75% Senior Notes contains covenants, including limitations of our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets.

In connection with the issuance of the 7.75% Senior Notes, we entered into registration rights agreements, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by January 23, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 7.75% Senior Notes. If we fail to comply with our obligations to register the 7.75% Senior Notes within the specified time periods, the 7.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable. On July 1, 2013, we filed a registration statement relating to the exchange offer for the 7.75% Senior Notes.

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 Dominion South Point, Tennessee Gas Pipeline, Transco Leidy Line; Mississippi Lime Southern Star; Barnett Shale and Marble Falls- primarily Waha but with smaller amounts sold into a variety of north Texas outlets; Raton ANR, Panhandle, and NGPL; Black Warrior Basin Southern Natural; New Albany Shale and Antrim Shale- primarily the Texas Gas Zone SL and Chicago Hub spot markets; and Niobrara formation primarily the Cheyenne Hub spot market. We attempt to sell the majority of our natural gas produced at monthly, fixed index prices and a smaller portion at index daily prices.

We do not hold firm transportation obligations on any pipeline that requires payment of transportation fees regardless of natural gas production volumes. As is customary in certain of our other operating areas, we occasionally commit a predictable portion of monthly production to the purchaser in order to maintain a gathering agreement.

Crude Oil. Crude oil produced from our wells flows directly into leasehold storage tanks where it is picked up by an oil company or a common carrier acting for an oil company. The crude oil is typically sold at the prevailing spot market price for each region, less appropriate trucking charges. We do not have delivery commitments for fixed and determinable quantities of crude oil in any future periods under existing contracts or agreements.

Natural Gas Liquids. NGLs 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 transport to end users or marketers operating on the receiving pipeline. The resulting dry natural gas is sold as mentioned above and our NGLs are generally priced using the Mont Belvieu (TX) regional processing hub. The cost to process and fractionate the NGLs from the gas stream is typically either a volumetric fee for the gas and liquids processed or a volumetric retention by the processing and fractionation facility. We do not have delivery commitments for fixed and determinable quantities of NGLs in any future periods under existing contracts or agreements.

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

- Well construction and completion. For each well that is drilled by a Drilling 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 a Drilling Partnership, we receive a fixed fee between $15,000 and $400,000, depending on the type of well drilled. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. Because we coinvest in the Drilling Partnerships, the net fee that we receive is reduced by our proportionate interest in the well;

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

- Gathering. Each royalty owner, Drilling Partnership and certain other working interest owners pay us a gathering fee, which in general is equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. 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 Drilling 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 natural gas 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 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 debt 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, oil and NGL 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, crude oil and NGL production operations in various shale plays throughout the United States. 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, which will expire on February 17, 2014. Through September 30, 2013, we have established production positions in the following operating areas:

- the Barnett Shale and Marble Falls play in the Fort Worth Basin in northern Texas, a hydro-carbon producing shale in which we established a position following our acquisitions of assets from Carrizo Oil & Gas, Inc. (Carrizo), Titan Operating, LLC (Titan) and DTE Energy Company (DTE) during 2012;

- coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming, where we established a position following our acquisition of certain assets from EP Energy during the three months ended September 30, 2013 (see Recent Developments);

- the Appalachia basin, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and 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;

- the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area; and

- other operating areas, including 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 New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile; the Antrim Shale in Michigan, where we produce out of the biogenic region of the shale similar to the New Albany Shale; and the Niobrara Shale in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled, both gross and for our interest, and the number of gross wells we turned in line during the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Gross wells drilled:				
Appalachia	3	8	3	22
Barnett/Marble Falls	22	9	53	9
Mississippi Lime/Hunton	6	2	19	4
Niobrara				51
Total	31	19	75	86
Our share of gross wells drilled(1):				
Appalachia	1	2	1	6
Barnett/Marble Falls	14	8	40	8
Mississippi Lime/Hunton	2		8	1
Niobrara				15
Total	17	10	49	30
Gross wells turned in line:				
Appalachia	13	13	14	41
Barnett/Marble Falls	17	3	54	3
Mississippi Lime/Hunton	5	2	15	2
Chattanooga				5
Niobrara		26		98
Total	35	44	83	149

(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 Drilling Partnerships.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes and production per day for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Production:(1)(2)(3)				
Appalachia:				
Natural gas (MMcf)	3,551	3,507	9,187	9,263
Oil (000 s Bbls)	29	24	79	75
Natural gas liquids (000 s Bbls)	1		1	4
Total (MMcfe)	3,730	3,651	9,672	9,735
Coal-bed Methane:				
Natural gas (MMcf)	7,037		7,037	
Oil (000 s Bbls)				
Natural gas liquids (000 s Bbls)				
Total (MMcfe)	7,037		7,037	
Barnett/Marble Falls:				
Natural gas (MMcf)	6,085	4,055	18,075	5,830
Oil (000 s Bbls)	83		231	
Natural gas liquids (000 s Bbls)	272	60	753	63
Total (MMcfe)	8,216	4,417	23,979	6,210
Mississippi Lime/Hunton:				
Natural gas (MMcf)	504	59	1,294	59
Oil (000 s Bbls)	26		39	
Natural gas liquids (000 s Bbls)	34		78	
Total (MMcfe)	863	59	1,997	59
Other Operating Areas:				
Natural gas (MMcf)	398	493	1,248	1,433
Oil (000 s Bbls)	2	2	5	5
Natural gas liquids (000 s Bbls)	36	38	107	112
Total (MMcfe)	627	730	1,923	2,132
Total production:				
Natural gas (MMcf)	17,574	8,115	36,840	16,586
Oil (000 s Bbls)	140	25	355	80
Natural gas liquids (000 s Bbls)	344	98	939	179
Total (MMcfe)	20,473	8,857	44,607	18,136
Production per day:(1)(2)(3)				
Appalachia:				
Natural gas (Mcfd)	38,594	38,123	33,651	33,807
Oil (Bpd)	312	259	291	273
Natural gas liquids (Bpd)	12	2	5	14
Total (Mcfed)	40,541	39,687	35,428	35,530
Coal-bed Methane: (4)				
Natural gas (Mcfd)	115,354		25,775	
Oil (Bpd)				
Natural gas liquids (Bpd)				

Total (Mcfed)	115,354		25,775	
Barnett/Marble Falls:(5)				
Natural gas (Mcfd)	66,145	49,440	66,208	21,278
Oil (Bpd)	899	2	847	1
Natural gas liquids (Bpd)	2,961	865	2,757	230
Total (Mcfed)	89,306	54,642	87,834	22,663
Mississippi Lime/Hunton:(6)				
Natural gas (Mcfd)	5,475	5,100	4,739	216
Oil (Bpd)	285	42	144	
Natural gas liquids (Bpd)	366	340	285	
Total (Mcfed)	9,382	7,391	7,315	216
Other Operating Areas:				
Natural gas (Mcfd)	4,321	5,363	4,571	5,230
Oil (Bpd)	21	16	19	17
Natural gas liquids (Bpd)	395	412	394	408
Total (Mcfed)	6,815	7,932	7,044	7,780
Total production per day:(4) (5) (6)				
Natural gas (Mcfd)	191,020	88,208	134,945	60,531
Oil (Bpd)	1,517	277	1,301	291
Natural gas liquids (Bpd)	3,734	1,067	3,441	652
Total (Mcfed)	222,529	96,275	163,397	66,189

(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 Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling 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 6 Mcf to one barrel.

(3) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama; Other operating areas include our production located in the Chattanooga, New Albany/Antrim and Niobrara Shales.

(4) Volumetric production per day for coal-bed methane for the three months ended September 30, 2013 includes production per day for the 61-day period from August 1, 2013, the date we began recognizing production from the assets following the completion of the EP Energy Acquisition, through September 30, 2013. Total coal-bed methane production per day for the nine months ended September 30, 2013 represents volume production for the full 273-day period. Total production per day represents total production volume over the 92 and 273 days within the three and nine months ended September 30, 2013, respectively.

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

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

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 79% of our proved reserves on an energy equivalent basis at December 31, 2012. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the three and nine months ended September 30, 2013 and 2012, along with our average production costs, taxes, and transportation and compression costs in each of the reported periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012

Production revenues (in thousands): [1]				
Appalachia:				
Natural gas revenue	$ 9,573	$ 8,226	$ 25,886	$ 28,328
Oil revenue	2,389	2,081	6,860	7,173
Natural gas liquids revenue	36	2	49	218
Total revenues	$ 11,998	$ 10,309	$ 32,795	$ 35,719
Coal-bed Methane:				
Natural gas revenue	$ 25,773	$	$ 25,773	$
Oil revenue				
Natural gas liquids revenue				
Total revenues	$ 25,773	$	$ 25,773	$
Barnett/Marble Falls:				
Natural gas revenue	$ 18,211	$ 9,666	$ 52,891	$ 13,606
Oil revenue	7,376	16	20,833	18
Natural gas liquids revenue	7,314	1,620	19,929	1,767
Total revenues	$ 32,901	$ 11,302	$ 93,653	$ 15,391
Mississippi Lime/Hunton:				
Natural gas revenue	$ 2,076	$ 112	$ 5,173	$ 112
Oil revenue	3,051		4,257	
Natural gas liquids revenue	1,645		3,340	
Total revenues	$ 6,772	$ 112	$ 12,770	$ 112
Other Operating Areas:				
Natural gas revenue	$ 1,717	$ 1,941	$ 5,066	$ 5,743
Oil revenue	177	142	444	428
Natural gas liquids revenue	994	893	2,989	3,930
Total revenues	$ 2,888	$ 2,976	$ 8,499	$ 10,101
Total production revenues:				
Natural gas revenue	$ 57,350	$ 19,945	$ 114,789	$ 47,789
Oil revenue	12,993	2,239	32,394	7,619

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Natural gas liquids revenue	9,989	2,515	26,307	5,915
Total revenues	$ 80,332	$ 24,699	$ 173,490	$ 61,323
Average sales price:				
Natural gas (per Mcf):(2)				
Total realized price, after hedge(3)	$ 3.46	$ 3.01	$ 3.39	$ 3.42
Total realized price, before hedge(3)	$ 3.20	$ 2.46	$ 3.19	$ 2.60
Oil (per Bbl):(2)				
Total realized price, after hedge	$ 93.07	$ 87.86	$ 91.19	$ 95.70
Total realized price, before hedge	$ 104.03	$ 84.30	$ 96.50	$ 93.38
Natural gas liquids (per Bbl) total realized price:(2)	$ 29.08	$ 25.61	$ 28.01	$ 33.09
Production costs (per Mcfe):(1) (2)				
Appalachia:				
Lease operating expenses(4)	$ 1.05	$ 1.02	$ 1.15	$ 1.01
Production taxes	0.09	0.08	0.08	0.09
Transportation and compression	0.49	0.40	0.49	0.35
	$ 1.64	$ 1.50	$ 1.73	$ 1.45
Coal-bed Methane:				
Lease operating expenses	$ 0.97	$	$ 0.97	$
Production taxes	0.25		0.25	
Transportation and compression	0.31		0.31	
	$ 1.52	$	$ 1.52	$
Barnett/Marble Falls:				
Lease operating expenses	$ 1.35	$ 0.55	$ 1.15	$ 0.51
Production taxes		0.18	0.19	0.19
Transportation and compression	0.07	0.15	0.09	0.19
	$ 1.42	$ 0.88	$ 1.43	$ 0.88
Mississippi Lime/Hunton:				
Lease operating expenses	$ 1.44	$	$ 1.49	$
Production taxes	0.17		0.22	
Transportation and compression	0.18		0.08	
	$ 1.79	$	$ 1.79	$
Other Operating Areas:				
Lease operating expenses	$ 0.75	$ 0.63	$ 0.72	$ 0.66
Production taxes	0.05	0.05	0.10	0.06
Transportation and compression	0.19	0.16	0.18	0.16
	$ 0.99	$ 0.85	$ 1.00	$ 0.89
Total production costs:				
Lease operating expenses(4)	$ 1.15	$ 0.75	$ 1.12	$ 0.80
Production taxes	0.11	0.13	0.17	0.12
Transportation and compression	0.24	0.25	0.22	0.27
	$ 1.50	$ 1.13	$ 1.51	$ 1.19

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama; Other operating areas include our production located in the Chattanooga, New Albany/Antrim and Niobrara Shales.

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

(3) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the three and nine months ended September 30, 2013 and 2012. Including the effect of this subordination, the average realized gas sales price was $3.26 per Mcf ($3.01 per Mcf before the effects of financial hedging) and $2.46 per Mcf ($1.91 per Mcf before the effects of financial hedging) for the three months ended September 30, 2013 and 2012, respectively, and $3.12 per Mcf ($2.92 per Mcf before the effects of financial hedging) and $2.88 per Mcf ($2.07 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2013 and 2012, 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 Drilling Partnerships for the three and nine months ended September 30, 2013 and 2012. Including the effects of these costs, Appalachia lease operating expenses per Mcfe were $0.73 per Mcfe ($1.31 per Mcfe for total production costs) and $0.29 per Mcfe ($0.77 per Mcfe for total production costs) for the three months ended September 30, 2013 and 2012, respectively, and $0.79 per Mcfe ($1.37 per Mcfe for total production costs) and $0.47 per Mcfe ($0.91 per Mcfe for total production costs) for the nine months ended September 30, 2013 and 2012, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $1.09 per Mcfe ($1.44 per Mcfe for total production costs) and $0.44 per Mcfe ($0.82 per Mcfe for total production costs) for the three months ended September 30, 2013 and 2012, respectively, and $1.04 per Mcfe ($1.43 per Mcfe for total production costs) and $0.50 per Mcfe ($0.90 per Mcfe for total production costs) for the nine months ended September 30, 2013 and 2012, respectively.

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Total natural gas revenues were $57.4 million for the three months ended September 30, 2013, an increase of $37.5 million from $19.9 million for the three months ended September 30, 2012. This increase consisted primarily of a $25.8 million increase attributable to natural gas revenue associated with the newly acquired coal-bed methane assets, an $8.5 million increase attributable to natural gas revenue associated with the Barnett Shale/Marble Falls assets, a $2.0 million increase attributable to the Mississippi Lime/Hunton assets, a $1.1 million decrease in gas revenues subordinated to the investor partners within our Drilling Partnerships, and a $0.1 million increase attributable to higher production volume on our legacy systems. Total oil revenues were $13.0 million for the three months ended September 30, 2013, an increase of $10.8 million from $2.2 million for the comparable prior year period due principally to a $7.4 million increase attributable to oil revenue associated with the Barnett Shale/Marble Falls assets and a $3.1 million increase attributable to oil revenue associated with the Mississippi Lime/Hunton assets. Total natural gas liquids revenues were $10.0 million for the three months ended September 30, 2013, an increase of $7.5 million from $2.5 million for the comparable prior year period. This increase was primarily attributable to $5.7 million of NGL revenue associated with the Barnett Shale/Marble Falls assets and $1.6 million of NGL revenue attributable to the Mississippi Lime/Hunton assets.

Appalachia production costs were $4.9 million for the three months ended September 30, 2013, an increase of $2.1 million from $2.8 million for the three months ended September 30, 2012. This increase was due to a $1.5 million decrease in our credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships and a $0.6 million increase in transportation, labor and other production costs. Production costs associated with our current quarter acquisition of coal-bed methane assets were $10.7 million for the three months ended September 30, 2013. Production costs associated with our 2012 acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime/Hunton plays were $13.2 million for the three months ended September 30, 2013 as compared to $3.9 million for the comparable prior year period. Production costs associated with our other operating areas were $0.6 million for the three months ended September 30, 2013, comparable with the three months ended September 30, 2012.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Total natural gas revenues were $114.8 million for the nine months ended September 30, 2013, an increase of $67.0 million from $47.8 million for the nine months ended September 30, 2012. This increase consisted of a $39.3 million increase attributable to natural gas revenue associated with the Barnett Shale/Marble Falls assets, a $25.8 million increase attributable to natural gas revenue associated with the newly acquired coal-bed methane assets, and a $5.1 million increase attributable to the Mississippi Lime/Hunton assets, partially offset by a $2.1 million decrease primarily attributable to lower realized natural gas prices for production volume on our legacy systems, and a $1.1 million increase in gas revenues subordinated to the investor partners within our Drilling Partnerships. Total oil revenues were $32.4 million for the nine months ended September 30, 2013, an increase of $24.8 million from $7.6 million for the comparable prior year period due to a $20.8 million increase attributable to oil revenue associated with the Barnett Shale/Marble Falls assets and a $4.3 million increase attributable to the Mississippi Lime/Hunton assets, partially offset by a $0.3 million decrease attributable to lower realized prices on our legacy systems during the current year period. Total natural gas liquids revenues were $26.3 million for the nine months ended September 30, 2013, an increase of $20.4 million from $5.9 million for the comparable prior year period. This increase was primarily attributable to $18.1 million of NGL revenue associated with the Barnett Shale/Marble Falls assets and $3.3 million of NGL revenue attributable to the Mississippi Lime/Hunton assets.

Appalachia production costs were $13.2 million for the nine months ended September 30, 2013, an increase of $4.3 million from $8.9 million for the nine months ended September 30, 2012. This increase was due to a $2.5 million increase in transportation, labor and other production costs, and a $1.8 million decrease in our credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships. Production costs associated with our current year acquisition of coal-bed methane assets were $10.7 million for the nine months ended September 30, 2013. Production costs associated with our 2012 acquisitions in the Barnett Shale/Marble Falls and Mississippi Lime/Hunton plays were $37.8 million for the nine months ended September 30, 2013 as compared to $5.5 million for the comparable prior year period. Production costs associated with our other operating areas were $1.9 million for the nine months ended September 30, 2013, comparable with the nine months ended September 30, 2012.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling 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 Drilling Partnerships during the three and nine months ended September 30, 2013 and 2012. There were no exploratory wells drilled during the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Drilling partnership investor capital:				
Raised	$ 10,964	$ 23,110	$ 25,000	$ 26,110
Deployed	$ 10,964	$ 36,317	$ 92,293	$ 92,277
Gross partnership wells drilled:				
Appalachia	3	8	3	22
Barnett/Marble Falls	22		29	
Mississippi Lime/Hunton	6	2	15	4
Niobrara				51
Total	31	10	47	77
Net partnership wells drilled:				
Appalachia	3	8	3	22
Barnett/Marble Falls	11		14	
Mississippi Lime/Hunton	6	2	15	3
Niobrara				51
Total	20	10	32	76

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Average construction and completion:				
Revenue per well	$ 1,786	$ 6,701	$ 3,871	$ 1,099
Cost per well	1,553	5,827	3,366	951
Gross profit per well	$ 233	$ 874	$ 505	$ 148
Gross profit margin	$ 1,430	$ 4,736	$ 12,038	$ 12,395
Partnership net wells associated with revenue recognized(1):				
Appalachia		3	8	17
Barnett/Marble Falls	5		7	
Mississippi Lime/Hunton	1	2	9	3
Chattanooga				1
Niobrara				63
Total	6	5	24	84

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

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Well construction and completion segment margin was $1.4 million for the three months ended September 30, 2013, a decrease of

$3.3 million from $4.7 million for three months ended September 30, 2012. This decrease consisted of a $3.5 million decrease associated with lower gross profit margin per well, partially offset by a $0.2 million increase related to a higher number of wells recognized for revenue within our Drilling Partnerships. Average revenue and cost per well decreased between periods due primarily to higher capital deployed for Marble Falls and Mississippi Lime wells within the Drilling Partnerships during the three months ended September 30, 2013, compared with higher capital deployed for Marcellus Shale and Utica Shale wells, which typically have a much higher cost per well as compared with our Marble Falls and Mississippi Lime wells, during the prior year period. Capital deployed during the three months ended September 30, 2013 decreased compared with the comparable prior year period due to the timing of funds raised during the period. As our drilling contracts with the Drilling Partnerships are on a cost-plus basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Well construction and completion segment margin was $12.0 million for the nine months ended September 30, 2013, a decrease of $0.4 million from $12.4 million for nine months ended September 30, 2012. This decrease consisted of an $8.9 million decrease related to a lower number of wells recognized for revenue within our Drilling Partnerships, partially offset by an $8.5 million increase associated with higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Marcellus Shale, Utica Shale, and Mississippi Lime play wells within the Drilling Partnerships during the nine months ended September 30, 2013, compared with higher capital deployed for lower cost Niobrara Shale wells during the prior year period.

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 Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in the Marble Falls and Niobrara Shale, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales.

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Administration and oversight fee revenues were $4.4 million for both the three month periods ended September 30, 2013 and 2012.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Administration and oversight fee revenues were $8.9 million for the nine months ended September 30, 2013, an increase of $0.3 million from $8.6 million for the nine months ended September 30, 2012. This increase was due to a current year period increase in the number of Mississippi Lime wells drilled, for which we receive higher administration fees, and to wells drilled within the Marble Falls play during the current year period.

Well Services

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

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Well services revenues were \$5.0 million for the three months ended September 30, 2013, a decrease of \$0.1 million from \$5.1 million for the three months ended September 30, 2012. Well services expenses were \$2.4 million for the three months ended September 30, 2013, an increase of \$0.2 million from \$2.2 million for the three months ended September 30, 2012. The decrease in well services revenue is primarily related to lower equipment rental revenue during the three months ended September 30, 2013 as compared with the comparable prior year period. The increase in well services expense is primarily related to higher well labor costs.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Well services revenues were \$14.7 million for the nine months ended September 30, 2013, a decrease of \$0.6 million from \$15.3 million for the nine months ended September 30, 2012. Well services expenses were \$7.0 million for the nine months ended September 30, 2013, a decrease of \$0.1 million from \$7.1 million for the nine months ended September 30, 2012. The decrease in well services revenue is primarily related to lower equipment rental revenue during the nine months ended September 30, 2013 as compared with the comparable prior year period. The decrease in well services expense is primarily related to lower well labor costs.

Gathering and Processing

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. Generally, we charge a gathering fee to our Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. 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 Drilling Partnerships by approximately 3%.

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Our net gathering and processing expense for the three months ended September 30, 2013 was $0.8 million, an increase of $0.4 million compared with $0.4 million for the three months ended September 30, 2012. This unfavorable increase was principally due to lower gross margin recognized within our New Albany Shale-based processing plants and decreases in our net revenues within the Appalachian Basin between the periods.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Our net gathering and processing expense for the nine months ended September 30, 2013 was $2.1 million, a decrease of $0.8 million compared with net expense of $2.9 million for the nine months ended September 30, 2012. This favorable decrease was principally due to decreases in our production volume and average realized natural gas price on production volume within the Appalachian Basin between the periods, as well as lower gross margin recognized within our New Albany Shale-based processing plants.

Other, net

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Other, net for the three months ended September 30, 2013 was an expense of $13.3 million, compared with income of $0.1 million for the three months ended September 30, 2012. The $13.4 million unfavorable movement compared with the prior year period was primarily due to the $13.2 million of premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from EP Energy in the current year period.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Other, net for the nine months ended September 30, 2013 was an expense of $14.6 million, compared with expense of $5.0 million for the nine months ended September 30, 2012. The $14.6 million of other expense for the nine months ended September 30, 2013 was primarily related to premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from EP Energy in the current year period. The $5.0 million of other expense for the nine months ended September 30, 2012 was primarily related to the premium amortization associated with swaption derivative contracts for production volumes related to wells acquired from Carrizo during the prior year period.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Total general and administrative expenses increased to $32.0 million for the three months ended September 30, 2013 compared with $16.1 million for the three months ended September 30, 2012. This increase was primarily due to a $17.1 million increase in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods, partially offset by a decrease in non-cash compensation expense.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Total general and administrative expenses increased to $63.8 million for the nine months ended September 30, 2013 compared with $48.4 million for the nine months ended September 30, 2012. This increase was primarily due to a $12.4 million increase in non-recurring transaction costs related to the acquisitions of assets in the current and prior year period, a $2.3 million increase in non-cash compensation expense, a $0.4 million decrease in net reimbursements we received under our transition services agreement with Chevron Corporation, which expired during the first quarter of 2012, and a $0.3 million increase in salaries, wages and other corporate activities.

Chevron Transaction Expense

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

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization increased to $41.7 million for the three months ended September 30, 2013 compared with $13.9 million for the comparable prior year period, which was due to a $27.3 million increase in our depletion expense resulting from the acquisitions we consummated during 2012 and 2013.

Total depreciation, depletion and amortization increased to $85.1 million for the nine months ended September 30, 2013 compared with $33.8 million for the comparable prior year period, which was due to a $50.5 million increase in our depletion expense resulting from the acquisitions we consummated during 2012 and 2013.

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 (in thousands, except for per Mcfe data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Depreciation, depletion and amortization:				
Depletion expense	$ 39,900	$ 12,576	$ 80,176	$ 29,663
Depreciation and amortization expense	1,756	1,342	4,885	4,185
	$ 41,656	$ 13,918	$ 85,061	$ 33,848
Depletion expense:				
Total	$ 39,900	$ 12,576	$ 80,176	$ 29,663
Depletion expense as a percentage of gas and oil production revenue	50%	51%	46%	48%
Depletion per Mcfe	$ 1.95	$ 1.42	$ 1.80	$ 1.64

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties.

For the three months ended September 30, 2013, depletion expense was $39.9 million, an increase of $27.3 million compared with $12.6 million for the three months ended September 30, 2012. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 50% for the three months ended September 30, 2013, compared with 51% for the three months ended September 30, 2012, which was primarily due to an increase in our oil and natural gas liquids volumes as a result of our acquisitions in 2012. Depletion expense per Mcfe increased to $1.95 for the three months ended September 30, 2013, compared to $1.42 for the prior year comparable period due to the increase in oil and natural gas liquids production between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

For the nine months ended September 30, 2013, depletion expense was $80.2 million, an increase of $50.5 million compared with $29.7 million for the nine months ended September 30, 2012. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 46% for the nine months ended September 30, 2013, compared with 48% for the nine months ended September 30, 2012, which was primarily due to an increase in our oil and natural gas liquids volumes as a result of our acquisitions in 2012, partially offset by a decrease in realized natural gas prices between the periods. Depletion expense per Mcfe increased to $1.80 for the nine months ended September 30, 2013, compared to $1.64 for the prior year comparable period primarily due to the increase in oil and natural gas liquids production between the periods. Depletion expense increased between periods principally due to an overall increase in production volume.

Interest Expense

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. Interest expense for the three months ended September 30, 2013 was $10.7 million as compared with $1.4 million for the comparable prior year period. The $9.3 million increase consisted of a $5.3 million increase associated with the issuance of our 7.75%

Senior Notes, $3.9 million associated with the issuance of $250.0 million of our 9.25% Senior Notes, a $2.3 million increase associated with amortization of deferred financing costs and a $0.4 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility, partially offset by interest that was capitalized on our ongoing capital projects. The increase in amortization associated with deferred financing costs includes $1.9 million associated with our amended credit facility, $0.2 million associated with our issuance of the 7.75% Senior Notes and $0.2 million associated with our issuance of the 9.25% Senior Notes.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. Interest expense for the nine months ended September 30, 2013 was $22.1 million as compared with $2.5 million for the comparable prior year period. The $19.6 million increase consisted of a $14.7 million increase associated with the issuance of our 7.75% Senior Notes, a $3.9 million increase associated with the issuance of our 9.25% Senior Notes, a $7.6 million increase associated with amortization of deferred financing costs and a $2.2 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility and term loan credit facility, partially offset by interest that was capitalized on our ongoing capital projects. The increase in amortization associated with deferred financing costs includes $3.2 million of accelerated amortization related to the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base subsequent to our issuance of the 7.75% Senior Notes, $3.2 million associated with our amended credit facility, $0.7 million associated with our issuance of the 7.75% Senior Notes and $0.2 million associated with our issuance of the 9.25% Senior Notes.

Gain (Loss) on Asset Sales and Disposal

Three Months Ended September 30, 2013 Compared with the Three Months Ended September 30, 2012. During the three months ended September 30, 2013 and 2012, we recognized losses on asset sales and disposals of $0.7 million and gains of approximately $2,000, respectively. The $0.7 million loss on asset sales and disposal for the three months ended September 30, 2013 pertained to management s decision not to drill wells on leasehold property that expired in the New Albany and Chattanooga Shales during the period.

Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012. During the nine months ended September 30, 2013 and 2012, we recognized losses on asset sales and disposals of $2.0 million and $7.0 million, respectively. The $2.0 million loss on asset sales and disposal for the nine months ended September 30, 2013 pertained to management s decision not to drill wells on leasehold property that expired in the New Albany and Chattanooga Shales during the period. During the nine months ended September 30, 2012, we recognized a $7.0 million loss on asset sales and disposal related to management s decision to terminate a farm-out agreement with a third party for well drilling in the South Knox area of the New Albany Shale that was originally entered into in 2010. The farm-out agreement contained certain well drilling milestones, which needed to be met in order for us to maintain ownership of the South Knox processing plant. During 2012, management decided not to continue progressing towards these milestones due to the current natural gas price environment. As a result, we forfeited our interest in the processing plant and recorded a loss related to the net book value of the assets during the nine months ended September 30, 2012.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling 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 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 Drilling Partnerships; and
- Debt principal payments through additional borrowings as they become due or by the issuance of additional common units or asset sales.

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

Cash Flows Nine Months Ended September 30, 2013 Compared with the Nine Months Ended September 30, 2012

Net cash provided by operating activities of $13.2 million for the nine months ended September 30, 2013 represented a favorable movement of $28.2 million from net cash used in operating activities of $15.0 million for the comparable prior year period. The $28.2 million favorable movement in net cash provided by operating activities resulted from a $47.3 million favorable movement in net income excluding non-cash items, partially offset by a $19.1 million unfavorable movement in working capital. The $47.3 million favorable movement in net income excluding non-cash items included a $51.2 million increase in depreciation, depletion and amortization expense, a $9.3 million favorable movement in non-cash gain on derivative value, a $7.6 million increase in amortization of deferred financing costs relating to our revolving and term loan credit facilities, our 9.25% Senior Notes and our 7.75% Senior Notes, and a $2.4 million increase in non-cash stock compensation, partially offset by an $18.3 million unfavorable movement in net loss and a $5.0 million unfavorable movement in loss on asset sales and disposal. The $51.2 million increase in depreciation, depletion and amortization expense is primarily related to the acquisitions of oil and gas properties made in 2012 and 2013. The $9.3 million favorable movement in non-cash gain on derivative value is primarily related to the movement in natural gas prices in comparison to our hedge prices for derivative contracts expiring during the respective periods. The $19.1 million unfavorable movement in working capital was principally due to a $38.7 million unfavorable movement in accounts payable and accrued liabilities, partially offset by a $19.6 million favorable movement in accounts receivable, prepaid expenses and other. The unfavorable movement in accounts payable and accrued liabilities was primarily due to an unfavorable movement in accrued well drilling and completion costs between respective periods, partially offset by a favorable movement in accounts payable and accrued liabilities between respective periods. The favorable movement in accounts receivable, prepaid expenses and other was primarily due to a favorable movement in subscriptions receivable between respective periods.

Net cash used in investing activities of $922.7 million for the nine months ended September 30, 2013 represented an unfavorable movement of $584.8 million from net cash used in investing activities of $337.9 million for the comparable prior year period. This unfavorable movement was primarily due to an increase in net cash paid for acquisitions during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012 and an increase in capital expenditures. See further discussion of capital expenditures under Capital Requirements .

Net cash provided by financing activities of $887.7 million for the nine months ended September 30, 2013 represented a favorable movement of $565.3 million from net cash provided by financing activities of $322.4 million for the comparable prior year period. This movement was principally due an increase of $510.5 million in net proceeds from the issuance of our 9.25% Senior Notes and 7.75% Senior Notes (see Senior Notes), an increase of $488.0 million in borrowings under our revolving credit facility, an increase of $200.7 million in net proceeds from the issuance of common limited partner units, and an increase of $86.6 million from the issuance of our Class C preferred units and warrants associated with the EP Energy Acquisition, partially offset by an increase of $636.4 million in repayments under our revolving and term loan credit facilities, a $68.6 million increase in cash distributions paid to unit holders, a $9.9 million unfavorable movement in deferred financing costs and other primarily associated with our revolving and term loan credit facilities, and a $5.6 million unfavorable movement in the net investment from owners. The gross amount of borrowings and repayments under our revolving credit facility included within net cash provided by financing activities in the consolidated 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 revolving credit facility, and payments, which generally occur throughout the period and increase borrowings under our revolving 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 the current levels of production margin over the long term. We calculate the estimate of maintenance capital expenditures by first multiplying our forecasted future full year production margin by our expected aggregate production decline of proved developed producing wells. Maintenance capital expenditures are then the estimated capitalized cost of wells that will generate an estimated first year margin equivalent to the production margin decline, assuming such wells are connected on the first day of the calendar year. We do not incur specific capital expenditures expressly for the purpose of maintaining or increasing production margin, but such amounts are a subset of wells expected to be drilled in future periods on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including utilization of public forward commodity exchange prices, current estimates for regional pricing differentials, estimated labor and material rates and other production costs. Estimates for maintenance capital expenditures in the current year are the sum of the estimate calculated in the prior year plus estimates for the decline in production margin from wells connected during the current year and production acquired through acquisitions; and

- expansion capital expenditures capital expenditures we make to increase the current levels of production margin for longer than the short-term, which includes the acquisition of new leasehold interests and the development and exploitation of existing leasehold interests through acquisitions, direct well drilling and investments in our Drilling Partnerships.

The following table summarizes our maintenance and expansion capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
Maintenance capital expenditures	$ 10,000	$ 3,350	$ 21,000	$ 6,850
Expansion capital expenditures	63,944	24,377	182,996	66,529
Total	$ 73,944	$ 27,727	$ 203,996	$ 73,379

During the three months ended September 30, 2013, our $73.9 million of total capital expenditures consisted primarily of $28.6 million for wells drilled exclusively for our own account compared with $7.6 million for the comparable prior year period, $27.7 million of investments in our Drilling Partnerships compared with $13.1 million for the prior year comparable period, $4.2 million of leasehold acquisition costs compared with $5.6 million for the prior year comparable period and $13.4 million of corporate and other costs compared with $1.4 million for the prior year comparable period, which primarily related to an increase in capitalized interest expense. Capital expenditures related to our investments in our Drilling Partnerships are generally incurred in periods subsequent to the period in which the funds were raised.

During the nine months ended September 30, 2013, our $204.0 million of total capital expenditures consisted primarily of $94.1 million for wells drilled exclusively for our own account compared with $7.8 million for the comparable prior year period, $64.9 million of investments in our Drilling Partnerships compared with $30.5 million for the prior year comparable period, $17.6 million of leasehold acquisition costs compared with $29.3 million for the prior year comparable period and $27.4 million of corporate and other costs compared with $5.8 million for the prior year comparable period, which primarily related to an increase in capitalized interest expense.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of September 30, 2013, we are committed to expend approximately $67.7 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 Drilling Partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of September 30, 2013, our off-balance sheet arrangements were limited to our letters of credit outstanding of $2.1 million and commitments to spend $67.7 million related to our drilling and completion and capital expenditures, excluding acquisitions.

CASH DISTRIBUTION POLICY

Our partnership agreement requires that we distribute 100% of available cash to our common and preferred 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 generally be distributed: first, 98% to our Class B preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class B preferred unit the greater of $0.40 and the distribution payable to common unitholders; second, 98% to our Class C preferred unitholders and 2% to our general partner until there has been distributed to each outstanding Class C preferred unit the greater of $0.51 and the distribution payable to common unitholders; thereafter 98% to our common unitholders 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 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

On July 31, 2013, in connection with the acquisition of assets from EP Energy (see Recent Developments), we entered into a second amended and restated credit agreement (Credit Agreement) with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amended and restated our existing revolving credit facility. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a borrowing base of $835.0 million and a maximum facility amount of $1.5 billion, which is scheduled to mature in July 2018. At September 30, 2013, $425.0 million was outstanding under the credit facility. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $2.1 million was outstanding at September 30, 2013. 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. Additionally, obligations under the facility are guaranteed by certain of our material subsidiaries, and any of our subsidiaries, other than subsidiary guarantors, are minor. Borrowings under the credit facility bear interest, at our election, at either LIBOR plus an applicable margin between 1.75% and 2.75% 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 0.75% and 1.75% per annum. We are also required to pay a fee on the unused portion of the borrowing base at a rate of 0.5% per annum if 50% or more of the borrowing base is utilized and 0.375% per annum if less than 50% of the borrowing base is utilized, which is included within interest expense on our consolidated statements of operations.

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, or engage in certain asset dispositions including a sale of all or substantially all of our assets. We were in compliance with these covenants as of September 30, 2013. 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 4.50 to 1.0 as of the last day of the quarter ended September 30, 2013, 4.25 to 1.0 as of the last day of the quarters ended December 31, 2013 and March 31, 2014 and 4.0 to 1.0 as of the last day of fiscal quarters ending thereafter and 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.

SENIOR NOTES

On July 30, 2013 we issued $250.0 million of 9.25% Senior Notes due August 15, 2021 (9.25% Senior Notes) in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million, net of underwriting fees and other offering costs of $5.5 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Recent Developments). The 9.25% Senior Notes were presented combined with a net $1.7 million unamortized discount as of September 30, 2013. Interest on the 9.25% Senior Notes accrued from July 30, 2013, and is payable semi-annually on February 15 and August 15, with the first interest payment date being February 15, 2014. At any time on or after August 15, 2017, we may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, we may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, we may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, we may redeem up to 35% of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if we sell certain assets and do not reinvest the proceeds or repay senior indebtedness or if we experience specific kinds of changes of control, we must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the 9.25% Senior Notes, we entered into a registration rights agreement, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated not later than 365 days after the issuance of the 9.25% Senior Notes. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 9.25% Senior Notes. If we fail to comply with our obligations to register the 9.25% Senior Notes within the specified time periods, the 9.25% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective as applicable.

On January 23, 2013, we issued $275.0 million of our 7.75% Senior Notes due 2021 (7.75% Senior Notes) in a private placement transaction at par. The net proceeds of approximately $267.7 million, net of underwriting fees and other offering costs of $7.3 million, were used to repay all of the indebtedness and accrued interest outstanding under our then-existing term loan credit facility and a portion of the amounts outstanding under our revolving credit facility. In connection with the retirement of our term loan credit facility and the reduction in our revolving credit facility borrowing base, we accelerated $3.2 million of amortization expense related to deferred financing costs during the nine months ended September 30, 2013. Interest on the 7.75% Senior Notes is payable semi-annually on January 15 and July 15. At any time prior to January 15, 2016, the 7.75% Senior Notes are redeemable up to 35% of the outstanding principal amount with the net cash proceeds of equity offerings at the redemption price of 107.75%. The 7.75% Senior Notes are also subject to repurchase at a price equal to 101% of the principal amount, plus accrued and unpaid interest, upon a change of control. At any time prior to January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

In connection with the issuance of the 7.75% Senior Notes, we entered into registration rights agreements, whereby we agreed to (a) file an exchange offer registration statement with the SEC to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by January 23, 2014. Under certain circumstances, in lieu of, or in addition to, a registered exchange offer, we have agreed to file a shelf registration statement with respect to the 7.75% Senior Notes. If we fail to comply with our obligations to register the 7.75% Senior Notes within the specified time periods, the 7.75% Senior Notes will be subject to additional interest, up to 1% per annum, until such time that the exchange offer is consummated or the shelf registration statement is declared effective, as applicable. On July 1, 2013, we filed a registration statement relating to the exchange offer for the 7.75% Senior Notes.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of our material subsidiaries. As of September 30, 2013, we were a holding company and had no independent assets or operations of our own. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, and any of our subsidiaries, other than the subsidiary guarantors, are minor. There are no restrictions on our ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 9.25% and 7.75% Senior Notes contains covenants, including limitations of our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets.

SECURED HEDGE FACILITY

At September 30, 2013, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership s ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

In addition, it will be an event of default under our revolving 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

Equity Offerings

In July 2013, in connection with the EP Energy Acquisition (see Recent Developments), we issued $86.6 million of our newly created Class C convertible preferred units to ATLS, at a negotiated price per unit of $23.10, which was the face value of the units. The Class C preferred units were offered and sold in a private transaction exempt from registration under Section 4(2) of the Securities Act. The Class C preferred units pay cash distributions in an amount equal to the greater of (i) $0.51 per unit and (ii) the distributions payable on each common unit at each declared quarterly distribution date. The initial Class C preferred distribution was paid for the quarter ending September 30, 2013. The Class C preferred units have no voting rights, except as set forth in the certificate of designation for the Class C preferred units, which provides, among other things, that the affirmative vote of 75% of the Class C Preferred Units is required to repeal such certificate of designation. Holders of the Class C preferred units have the right to convert the Class C preferred units on a one-for-one basis, in whole or in part, into common units at any time before July 31, 2016. Unless previously converted, all Class C preferred units will convert into common units on July 31, 2016. Upon issuance of the Class C preferred units, ATLS, as purchaser of the Class C preferred units, received 562,497 warrants to purchase our common units at an exercise price equal to the face value of the Class C preferred units.

Upon issuance of the Class C preferred units and warrants on July 31, 2013, we entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the SEC to register the resale of the common units issuable upon conversion of the Class C preferred units and upon exercise of the warrants. We agreed to use commercially reasonable efforts to file such registration statement within 90 days of the conversion of the Class C preferred units into common units or the exercise of the warrants.

In June 2013, in connection with the EP Energy Acquisition (see Recent Developments), we sold an aggregate of 14,950,000 of our common limited partner units (including a 1,950,000 over-allotment) in a public offering at a price of $21.75 per unit, yielding net proceeds of approximately $313.1 million. We utilized the net proceeds from the sale to repay the outstanding balance under our revolving credit facility (see Credit Facility).

In May 2013, we entered into an equity distribution program with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution program, we may sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. Sales of common limited partner units, if any, may be made in negotiated transactions or transactions that are deemed to be at-the-market offerings as defined in Rule 415 of the Securities Act of 1933, as amended, including sales made directly on the New York Stock Exchange, the existing trading market for the common limited partner units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay each of the agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common limited partner units sold through such agent. During the nine months ended September 30, 2013, we issued 309,174 common limited partner units under the equity distribution program for net proceeds of $7.0 million, net of $0.4 million in commissions paid. No common limited partner units were issued under the equity distribution program during the three months ended September 30, 2013. We utilized the net proceeds from the sale to repay borrowings outstanding under our revolving credit facility.

In November and December 2012, in connection with entering into a purchase agreement to acquire certain producing wells and net acreage from DTE, we sold an aggregate of 7,898,210 of our common limited partner units in a public offering at a price of $23.01 per unit, yielding net proceeds of approximately $174.5 million. We utilized the net proceeds from the sale to repay a portion of the outstanding balance under our revolving credit facility and $2.2 million under our term loan credit facility.

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

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

In April 2012, we completed the acquisition of certain oil and gas assets from Carrizo. 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 net proceeds of $119.5 million, of which $5.0 million was purchased by certain of our executives. The common units issued by us were subject to a registration rights agreement entered into in connection with the transaction. The registration rights agreement stipulated that we would (a) file a registration statement with the SEC by October 30, 2012 and (b) cause the registration statement to be declared effective by the SEC by December 31, 2012. On July 11, 2012, we filed a registration statement with the SEC for the common units subject to the registration rights agreement in satisfaction of the registration requirements of the registration rights agreement, and on August 28, 2012, the registration statement was declared effective by the SEC.

Common Unit Distribution

In February 2012, the board of directors of ATLS   general partner approved the distribution of approximately 5.24 million of our 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 our limited partner units represented approximately 20.0% of our common limited partner units outstanding.

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 financial statements was included in our Annual Report on Form 10-K for the year ended December 31, 2012, and we summarize our significant accounting policies within our consolidated 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.

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 , recent increases in natural gas drilling have driven an increase in the supply of natural gas and put a downward pressure on domestic prices. Further declines in natural gas prices may result in additional impairment charges in future periods.

There were no impairments of proved or unproved gas and oil properties recorded by us for the three and nine months ended September 30, 2013 and 2012. During the year ended December 31, 2012, we recognized $9.5 million of asset impairments related to gas and oil properties within property, plant and equipment on our consolidated balance sheet for shallow natural gas wells in the Antrim and Niobrara Shales. These impairments related to the carrying amounts of these gas and oil properties being in excess of our estimate of their fair values at December 31, 2012. The estimate of fair values 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, 2012.

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

There were no goodwill impairments recognized by us during the three and nine months ended September 30, 2013 and 2012.

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 that are defined as Level 3. Estimates of the fair value of asset retirement obligations 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.

During the three and nine months ended September 30, 2013, we completed the EP Energy Acquisition. During the year ended December 31, 2012, we completed the acquisitions of certain oil and gas assets from Carrizo and reserves and associated assets from Titan and DTE. 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 our existing methodology for recognizing an estimated liability for the plugging and abandonment of our gas and oil wells (see Item 1: Financial Statements Note 6). These inputs require significant judgments and estimates by management at the time of the valuation and are subject to change.

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, 2012, 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

We recognize an estimated liability for the plugging and abandonment of our gas and oil wells and related facilities. We also recognize a liability for our 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. We also consider the estimated salvage value in the calculation of depreciation, depletion and amortization.

The estimated liability is based on our 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 is discounted using an assumed credit-adjusted risk-free interest 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. 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. We have no assets legally restricted for purposes of settling asset retirement obligations. Except for our gas and oil properties, we believe that there are no other material retirement obligations associated with tangible long lived assets.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on September 30, 2013. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

Current market conditions elevate our concern over counterparty risks and may adversely affect the ability of these counterparties to fulfill their obligations to us, if any. The counterparties related to our commodity derivative contracts are banking institutions or their affiliates, who also participate in our revolving credit facility. The creditworthiness of our counterparties is constantly monitored, and we currently believe them to be financially viable. We are not aware of any inability on the part of our counterparties to perform under their contracts and believe our exposure to non-performance is remote.

Interest Rate Risk. At September 30, 2013, $425.0 million was outstanding under our revolving credit facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would change our consolidated interest expense for the twelve month period ending September 30, 2014 by $4.3 million.

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 average commodity prices would result in a change to our consolidated operating income for the twelve-month period ending September 30, 2014 of approximately $12.0 million.

Realized pricing of our natural gas, oil, and NGL production is primarily driven by the prevailing worldwide prices for crude oil and spot market prices applicable to United States natural gas, oil and NGL production. Pricing for natural gas, oil and NGL production has been volatile and unpredictable for many years. To limit our exposure to changing natural gas, oil and NGL prices, we enter into natural gas and oil, swap, put options and costless collar option contracts. At any point in time, such contracts may include regulated NYMEX futures and options contracts and non-regulated over-the-counter (OTC) futures contracts with qualified counterparties. OTC contracts are generally financial contracts which are settled with financial payments or receipts and generally do not require delivery of physical hydrocarbons. NYMEX contracts are generally settled with offsetting positions, but may be settled by the delivery of natural gas. Crude oil contracts are based on a West Texas Intermediate (WTI) index. NGL fixed price swaps are priced based on a WTI crude oil index. These contracts have qualified and been designated as cash flow hedges and been recorded at their fair values.

At September 30, 2013, 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]
2013	15,597,400	$ 3.909
2014	60,153,000	$ 4.152
2015	50,274,500	$ 4.240
2016	43,946,300	$ 4.318
2017	24,840,000	$ 4.532
2018	3,960,000	$ 4.716

Natural Gas Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)[1]	Average Floor and Cap (per MMBtu)[1]
2013	Puts purchased	1,380,000	$ 4.395
2013	Calls sold	1,380,000	$ 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

Natural Gas Put Options   Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)[1]	Average Fixed Price (per MMBtu)[1]
2013	Puts purchased	540,000	$ 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

Natural Gas Liquids Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]
2013	36,000	$ 93.656
2014	105,000	$ 91.571
2015	96,000	$ 88.550
2016	84,000	$ 85.651
2017	60,000	$ 83.780

Natural Gas Liquids Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]
2014	2,520,000	$ 0.303

Natural Gas Liquids Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]
2013	3,864,000	$ 1.084
2014	11,592,000	$ 0.996

Crude Oil Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]
2013	170,200	$ 93.738
2014	552,000	$ 92.668
2015	567,000	$ 88.144

2016	225,000	$ 85.523
2017	132,000	$ 83.305

Crude Oil Costless Collars

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]
2013	Puts purchased	20,000	$ 90.000
2013	Calls sold	20,000	$ 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; Gal represents gallons.

ITEM 4: CONTROLS AND PROCEDURES

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

Under the supervision of our general partner s Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our general partner s Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2013, our disclosure controls and procedures were effective at the reasonable assurance level.

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

In July 2013, we acquired certain assets from EP Energy (see Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Developments). We are continuing to integrate this system s 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 system s historical internal controls over financial reporting in future fiscal reporting periods.

PART II

ITEM 1: LEGAL PROCEEDINGS

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

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

In early September 2013, Atlas Energy Tennessee, LLC, was dismissed as a party on jurisdictional grounds.

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

ITEM 6: EXHIBITS

Exhibit No.	Description
2.1	Purchase and Sale Agreement, dated as of June 9, 2013, by and among EP Energy E&P Company, L.P., EPE Nominee Corp. and Atlas Resource Partners, L.P. 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(14)
2.2	Assignment & Assumption Agreement, dated as of June 9, 2013, between Atlas Resource Partners, L.P. and Atlas Energy, L.P. (14)

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(12)
3.2(c)	Amendment No. 2 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of July 31, 2013(23)
3.3	Certificate of Formation of Atlas Resource Partners GP, LLC(2)
3.4(a)	Amended and Restated Limited Liability Company Agreement of Atlas Resource

	Partners GP, LLC[18]
3.4(b)	Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC
4.1	Indenture dated as of January 23, 2013 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the subsidiaries named therein and U.S. Bank National Association[20]
4.2	Indenture dated as of July 30, 2013, by and between Atlas Resource Escrow Corporation and Wells Fargo Bank, National Association[22]
4.3	Supplemental Indenture dated as of July 31, 2013, by and among Atlas

	Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[22]
4.4	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class B Preferred Units, dated as of July 25, 2013[12]
4.5	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class C Convertible Preferred Units, dated as of July

	31, 2013[23]
4.6	Warrant to Purchase Common Units[23]
10.1	Pennsylvania Operating Services Agreement dated as of February 17, 2011 between Chevron North America Exploration and Production (f/k/a Atlas Energy, Inc.), Atlas Energy, L.P. (f/k/a Atlas Pipeline Holdings, L.P.) and Atlas Resources, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission[5]

10.2	Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.3	Amendment No. 1 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC,

	Viking Resources, LLC, and Resource Energy, LLC, dated as of January 6, 2011[5]
10.4	Amendment No. 2 to the Base Contract for Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated as of February 2, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission[5]
10.5	Transaction Confirmation, Supply Contract No. 0001, under Base Contract for

	Sale and Purchase of Natural Gas dated as of November 8, 2010 between Chevron Natural Gas, a division of Chevron U.S.A. Inc. and Atlas Resources, LLC, Viking Resources, LLC, and Resource Energy, LLC, dated February 17, 2011. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.6	Gas Gathering Agreement for Natural Gas on the Legacy Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating

	Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.7	Gas Gathering Agreement for Natural Gas on the Expansion Appalachian System dated as of June 1, 2009 between Laurel Mountain Midstream, LLC and Atlas America, LLC, Atlas Energy Resources, LLC, Atlas Energy Operating Company, LLC, Atlas Noble, LLC, Resource Energy, LLC, Viking

	Resources, LLC, Atlas Pipeline Partners, L.P. and Atlas Pipeline Operating Partnership, L.P. Specific terms in this exhibit have been redacted, as marked by three asterisks (***), because confidential treatment for those terms has been requested. The redacted material has been separately filed with the Securities and Exchange Commission(5)
10.8	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Edward E. Cohen, dated as of November 8, 2010(6)
10.9	Non-Competition and Non-Solicitation Agreement, by and between Chevron Corporation and Jonathan Z. Cohen, dated as of November 8, 2010(6)
10.10(a)	Credit Agreement

	between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders[3]
10.10(b)	First Amendment to Credit Agreement, dated as of April 30, 2012, between Atlas Resource Partners, L.P. and Wells Fargo Bank, N.A., as administrative agent for the Lenders[10]
10.10(c)	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[12]
10.10(d)	Third Amendment to Amended and Restated Credit Agreement dated as of December 20, 2012[15]
10.10(e)	Fourth Amendment to Amended and Restated Credit

Agreement dated
as of January 11,
2013(16)

10.10(f)	Fifth Amendment to Amended and Restated Credit Facility dated as of May 30, 2013[1]
10.11	Secured Hedge Facility Agreement, among Atlas Resources, LLC, the participating partnerships from time to time party thereto, the hedge providers from time to time party thereto and Wells Fargo Bank, N.A., as collateral agent for the hedge providers[3]
10.12	Second Amended and Restated Credit Agreement dated July 31, 2013 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[23]
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(8)
10.15	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan(8)
10.16	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan(8)
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	Employment Agreement between Atlas Energy, L.P. and Daniel Herz dated as of November 4, 2011[24]
10.21	Common Unit Purchase Agreement, dated as of March 15, 2012, among Atlas Resource Partners, L.P. and the various purchasers party thereto[9]
10.22	Registration Rights Agreement, dated as of April 30, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein[10]
10.23	Registration Rights Agreement, dated as of July 25, 2012, among Atlas Resource Partners, L.P. and the various parties listed therein[12]

10.24	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(13)
10.25	Underwriting Agreement dated November 20, 2012, among Atlas Resource Partners, L.P., Wells Fargo Securities, LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets, Inc., Deutsche Bank Securities Inc., J.P. Morgan Securities LLC, Morgan Stanley & Co. LLC and RBC Capital Markets, LLC, as representatives of the several underwriters(19)

10.26	Second Lien Credit Agreement, dated as of December 20, 2012, by and among Atlas Resource Partners, L.P, the lenders party thereto and Wells Fargo Energy Capital, Inc. as administrative agent for the lenders(15)
10.27	Purchase Agreement dated as of January 16, 2013, among Atlas Resource Partners, L.P., Atlas Resource Finance Corporation and the initial purchasers named therein(17)
10.28	Registration Rights Agreement, dated as of January 23, 2013 among Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation and the initial purchasers named therein (20)

10.29	Distribution Agreement dated as of May 10, 2013, between Atlas Resource Partners, L.P. and Deutsche Bank Securities Inc., as representative of the several agents(11)

10.30	Class C Preferred Unit Purchase Agreement, dated as of June 9, 2013, between Atlas Resource Partners, L.P. and Atlas Energy, L.P. (14)
10.31	Underwriting Agreement, dated June 10, 2013, among Atlas Resource Partners, L.P. and the underwriters named therein(21)
10.32	Registration Rights Agreement dated as of July 31, 2013, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein and Deutsche Bank Securities, Inc., for itself and on behalf of the Initial Purchasers(22)
10.33	Registration Rights Agreement dated as of July 31, 2013, by and among Atlas Energy, L.P. and Atlas Resource Partners, L.P. (23)
12.1	Statement of Computation of Ratio of Earnings to Fixed Charges
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(25)
101.SCH	XBRL Schema Document(25)
101.CAL	XBRL Calculation Linkbase Document(25)
101.LAB	XBRL Label Linkbase Document(25)
101.PRE	XBRL Presentation Linkbase Document(25)
101.DEF	XBRL Definition Linkbase Document(25)

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 31, 2013.
(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 Annual Report on Form 10-K filed for the year ended December 31, 2011.
(9) Previously filed as an exhibit to our Current Report on Form 8-K filed on March 21, 2012.
(10) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 1, 2012.
(11) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 10, 2013.
(12) Previously filed as an exhibit to our Current Report on Form 8-K filed on July 26, 2012.
(13) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2012.
(14) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 10, 2013.
(15) Previously filed as an exhibit to our Current Report on Form 8-K filed on December 26, 2012.

(16) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 11, 2013.
(17) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 17, 2013.
(18) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2012.
(19) Previously filed as an exhibit to our Current Report on Form 8-K filed on November 27, 2012.

(20) Previously filed as an exhibit to our Current Report on Form 8-K filed on January 25, 2013.
(21) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 14, 2013.
(22) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 2, 2013.
(23) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 6, 2013.
(24) Previously filed as an exhibit to Atlas Energy s Quarterly Report on Form 10-Q for the quarter ended June 30, 2013.
(25) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). Users of this data are advised pursuant to Rule 406T of Regulation S-T that the interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of section 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise not subject to liability under these sections. The financial information contained in the XBRL-related documents is unaudited or unreviewed .

SIGNATURES

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

		ATLAS RESOURCE PARTNERS, L.P.
		By: Atlas Resource Partners GP, LLC, its General Partner
Date:	November 8, 2013	By: /s/ EDWARD E. COHEN
		Edward E. Cohen
		Chairman of the Board and Chief Executive Officer of the General Partner
Date:	November 8, 2013	By: /s/ SEAN P. MCGRATH
		Sean P. McGrath
		Chief Financial Officer of the General Partner
Date:	November 8, 2013	By: /s/ JEFFREY M. SLOTTERBACK
		Jeffrey M. Slotterback
		Chief Accounting Officer of the General Partner