Atlas Resource Partners, L.P.
Form 10-Q
November 09, 2015

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, 2015

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.)
	15275

Park Place Corporate Center One
1000 Commerce Drive, Suite 400
Pittsburgh, Pennsylvania
(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 x	Accelerated filer ¨
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, 2015 was 102,154,241.

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)

	September 30, 2015	December 31, 2014
ASSETS		
Current assets:		
Cash and cash equivalents	$2,418	$15,247
Accounts receivable	89,402	114,520
Advances to affiliates	1,178	—
Current portion of derivative asset	146,622	144,259
Subscriptions receivable	23,054	32,398
Prepaid expenses and other	25,407	26,296
Total current assets	288,081	332,720
Property, plant and equipment, net	1,534,718	2,263,820
Goodwill and intangible assets, net	14,154	14,330
Long-term derivative asset	205,979	130,602
Other assets, net	53,826	50,081
	$2,096,758	$2,791,553
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$82,209	$111,198
Advances from affiliates	—	2,249
Liabilities associated with drilling contracts	—	40,611
Current portion of derivative payable to Drilling Partnerships	1,881	932
Accrued well drilling and completion costs	56,300	80,404
Accrued interest	10,785	26,452
Distribution payable	14,234	20,876
Deferred acquisition purchase price	21,667	23,445
Accrued liabilities	42,669	33,406
Total current liabilities	229,745	339,573
Long-term debt	1,505,047	1,394,460
Asset retirement obligations	112,435	107,950

Other long-term liabilities	4,654	2,033
Commitments and contingencies		
Partners' Capital:		
General partner's interest	(27,465)	(13,697)
Preferred limited partners' interests	188,910	163,522
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	35,854	605,065
Accumulated other comprehensive income	46,402	191,471
Total partners' capital	244,877	947,537
	$2,096,758	$2,791,553

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,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues:				
Gas and oil production	$90,734	$129,399	$292,243	$337,893
Well construction and completion	23,054	61,204	63,665	126,917
Gathering and processing	1,685	3,061	6,046	11,287
Administration and oversight	5,495	6,177	7,301	12,072
Well services	5,842	6,597	18,568	18,441
Gain on mark-to-market derivatives	131,065	—	209,706	—
Other, net	20	261	80	343
Total revenues	257,895	206,699	597,609	506,953
Costs and expenses:				
Gas and oil production	41,591	51,391	130,224	133,038
Well construction and completion	20,046	53,221	55,361	110,363
Gathering and processing	2,473	3,214	7,406	11,900
Well services	2,398	2,617	6,735	7,525
General and administrative	13,978	13,124	44,400	50,894
Depreciation, depletion and amortization	40,463	64,578	125,948	176,077
Asset impairment	672,246	—	672,246	—
Total costs and expenses	793,195	188,145	1,042,320	489,797
Operating income (loss)	(535,300)	18,554	(444,711)	17,156
Interest expense	(25,192)	(16,577)	(75,105)	(43,028)
Loss on asset sales and disposal	(362)	(92)	(276)	(1,686)
Net income (loss)	(560,854)	1,885	(520,092)	(27,558)
Preferred limited partner dividends	(4,293)	(4,475)	(12,180)	(13,298)
Net loss attributable to common limited partners and the general partner	$(565,147)	$(2,590)	$(532,272)	$(40,856)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	$(553,844)	$(5,599)	$(521,627)	$(48,283)
General partner's interest	(11,303)	3,009	(10,645)	7,427
	$(565,147)	$(2,590)	$(532,272)	$(40,856)

Net loss attributable to common limited partners and the general partner				
Net loss attributable to common limited partners per unit:				
Basic	$(5.73)	$(0.07)	$(5.74)	$(0.67)
Diluted	$(5.73)	$(0.07)	$(5.74)	$(0.67)
Weighted average common limited partner units outstanding:				
Basic	96,660	81,521	90,943	72,288
Diluted	96,660	81,521	90,943	72,288

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,	
	2015	2014	2015	2014
Net income (loss)	$(560,854)	$1,885	$(520,092)	$(27,558)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	—	70,362	—	5,268
Reclassification adjustment for unrealized gains used to offset impairment expense	(68,021)	—	(68,021)	—
Less: reclassification adjustment for realized (gains) losses of cash flow hedges in net income (loss)	(23,927)	(1,388)	(77,048)	22,703
Total other comprehensive income (loss)	(91,948)	68,974	(145,069)	27,971
Comprehensive income (loss) attributable to common and preferred limited partners and the general partner	$(652,802)	$70,859	$(665,161)	$413

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL

(in thousands, except unit data)

(Unaudited)

est	Preferred Limited Partners' Interest								Common Limited Partners' Interests		Class C Com Limited Partner Warra	
	Class B		Class C		Class D		Class E					
mount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Ar
(13,697)	39,654	$983	3,749,986	$85,501	3,200,000	$77,038	—	$—	85,346,941	$605,065	562,497	$1
—	—	—	—	—	—	—	—	—		(44,893)	—	–
—	—	—	—	—	890,328	20,997	256,083	5,930	14,904,934	89,409	—	–
—	—	—	—	—	—	—	—		459,189	4,600	—	–
1,142	—	8	—	100	—	(231)	—	(172)	—	5,830	—	–
(4,265)	—	(42)	—	(5,937)	—	(6,287)	—	(173)	—	(102,999)	—	–
—	—	—	—	—	—	—	—	—	—	(516)	—	–
—	(39,654)	(985)	—	—	—	—	—	—	39,859	985	—	–
(10,645)	—	36	—	5,738	—	6,088	—	318	—	(521,627)	—	–
—	—	—	—	—	—	—	—	—	—	—	—	–

(27,465)	—	$—	3,749,986	$85,402	4,090,328	$97,605	256,083	$5,903	100,750,923	$35,854	562,497	$1

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, 2015	Nine Months Ended September 30, 2014
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(520,092)	$(27,558)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depreciation, depletion and amortization	125,948	176,077
Asset impairment	672,246	—
Unrealized gain on derivatives	(192,447)	—
(Gain) loss on asset sales and disposal	(190)	1,686
Non-cash compensation expense	4,497	6,291
Amortization of deferred financing costs	13,151	6,098
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	148,879	(90,204)
Accounts payable and accrued liabilities	(150,684)	14,695
Net cash provided by operating activities	101,308	87,085
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(102,290)	(150,579)
Net cash paid for acquisitions	(36,967)	(510,029)
Other	394	(98)
Net cash used in investing activities	(138,863)	(660,706)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	560,341	1,034,000
Repayments under credit facilities	(449,754)	(793,000)
Distributions paid to unitholders	(119,703)	(162,290)
Net proceeds from long term debt	—	97,386
Net proceeds from issuance of common limited partner units	89,409	426,253
Net proceeds from issuance of preferred units	6,927	—
Arkoma transaction adjustment	(44,893)	(12,266)
Deferred financing costs, distribution equivalent rights and other	(17,601)	(13,123)
Net cash provided by financing activities	24,726	576,960
Net change in cash and cash equivalents	(12,829)	3,339
Cash and cash equivalents, beginning of year	15,247	1,828
Cash and cash equivalents, end of period	$2,418	$5,167

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2015

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the “Partnership”) is a publicly traded (NYSE: ARP) Delaware master-limited partnership (“MLP”) 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 (the “Drilling Partnerships”), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities.

On February 27, 2015, the Partnership’s general partner, Atlas Energy Group, LLC (“Atlas Energy Group”; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. (“Atlas Energy”), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as “ATLS”). Atlas Energy Group manages the Partnership’s operations and activities through its ownership of the Partnership’s general partner interest. Concurrent with Atlas Energy Group’s unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. (“Targa”; NYSE: TRGP) and ceased trading. At September 30, 2015, Atlas Energy Group owned 100% of the Partnership’s general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 23.6% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

In addition to its general and limited partner interest in the Partnership, ATLS also holds general and limited partner interests in Atlas Growth Partners, L.P. (“AGP”), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale, and in Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2014 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, 2014. 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, 2015 may not necessarily be indicative of the results of operations for the full year ending December 31, 2015.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership’s consolidated balance sheets at September 30, 2015 and December 31, 2014 and the consolidated statements of operations for the three and nine months ended September 30, 2015 and 2014 include the accounts of the Partnership and its wholly-owned subsidiaries. Transactions between the Partnership and other ATLS operations have been identified in the consolidated financial statements as transactions between affiliates, where applicable. All material intercompany transactions have been eliminated.

On June 5, 2015, the Partnership acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS (“Arkoma Acquisition”). Management of the Partnership determined that the Arkoma Acquisition constituted a transaction between entities under common control. In comparison to the acquisition method of accounting, whereby the purchase price for the asset acquisition would have been allocated to identifiable Arkoma assets and liabilities based upon their fair values with any excess treated as goodwill, transfers between entities under common control require that assets and liabilities be recognized by the acquirer at historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners’ capital on the Partnership’s consolidated balance sheets. Also, in comparison to the acquisition method of accounting, whereby the results of operations and the financial position of the acquisition of Arkoma assets would have been included in the Partnership’s consolidated financial statements from the date of acquisition, transfers between entities under common control require the acquirer to reflect the effect to the assets acquired and liabilities assumed and the related results of operations at the beginning of the period during which it was acquired and retrospectively adjust its prior period consolidated financial statements to furnish comparative information. As such, the Partnership reflected the impact of the Arkoma Acquisition on its consolidated financial statements in the following manner:

- Recognized the assets acquired and liabilities assumed from the Arkoma Acquisition at their historical carrying value at the date of transfer, with any difference between the purchase price and the net book value of the assets recognized as an adjustment to partners' capital;
- Retrospectively adjusted its consolidated financial statements for any date prior to June 5, 2015, the date of acquisition, to reflect its results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period; and
- Adjusted the presentation of the Partnership's consolidated statements of operations for the three and nine months ended September 30, 2014 to reflect the results of operations attributable to the Arkoma assets prior to the date of acquisition to determine income attributable to common limited partners.

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 Drilling Partnerships in which the Partnership has an interest. Such interests generally approximate 30%. 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 (see "Property, Plant and Equipment").

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. 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, 2015 and 2014 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 accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customers' 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, 2015 and December 31, 2014, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $8.7 million and $8.9 million of inventory at September 30, 2015 and December 31, 2014, respectively, 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 that 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 that 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 Property, Plant and Equipment

The Partnership reviews its property, plant and equipment 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 flows from the sale of production of reserves are 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 future 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, 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 recognizing its proportionate share of limited partners' Drilling Partnership external operating expenses. 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 Drilling Partnership's wells become uneconomic to the Drilling Partnership under the terms of the Drilling Partnership's drilling and operating agreement in order to recover these excess reserves, in addition to the Partnership becoming responsible for paying associated future operating, development and plugging costs of the well interests acquired, and to acquire any additional residual interests in the wells held by the Drilling Partnership's limited partners. The acquisition of any such uneconomic well interest from the Drilling Partnership by the Partnership is governed under the Drilling Partnership's limited partnership 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.

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 6.5% and 5.4% for the three months ended September 30, 2015 and 2014, respectively, and 6.4% and 5.7% for the nine months ended September 30, 2015 and 2014, respectively. The aggregate amount of interest capitalized by the Partnership was $4.0 million and $3.7 million for the three months ended September 30, 2015 and 2014, respectively, and $12.0 million and $9.4 million for the nine months ended September 30, 2015 and 2014, 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. ARP reviews intangible 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 following table reflects the components of intangible assets being amortized at September 30, 2015 and December 31, 2014 (in thousands):

	September 30,	December 31,	Estimated Useful Lives

	2015	2014	In Years
Gross Carrying Amount	$ 14,344	$ 14,344	13
Accumulated Amortization	(13,829)	(13,653)	
Net Carrying Amount	$ 515	$ 691	

Amortization expense on intangible assets was $0.1 million for both the three months ended September 30, 2015 and 2014. Amortization expense on intangible assets was $0.2 million for both the nine months ended September 30, 2015 and 2014. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2015 - $0.2 million; 2016 - $0.1 million; 2017 - $0.1 million; 2018 - $0.1 million; and 2019 - $0.1 million.

Goodwill

At September 30, 2015 and December 31, 2014, the Partnership had $13.6 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, 2015 and 2014.

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. 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.

As a result of its goodwill impairment evaluation at December 31, 2014, the Partnership recognized an $18.1 million non-cash impairment charge within asset impairments on its consolidated statement of operations for the year ended December 31, 2014. The goodwill impairment resulted from the reduction in the Partnership's estimated fair value of its gas and oil production reporting unit in comparison to its carrying amount at December 31, 2014. The Partnership's estimated fair value of its gas and oil production reporting unit was impacted by a decline in overall commodity prices during the fourth quarter of 2014.

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. On January 1, 2015, the Partnership discontinued hedge accounting through de-designation for all of its existing commodity derivatives which were qualified as hedges. As such, subsequent changes in fair value after December 31, 2014 of these derivatives are recognized immediately within gain (loss) on mark-to-market derivatives in the Partnership's consolidated statements of operations, while the fair values of the instruments recorded in accumulated other comprehensive income as of December 31, 2014 will be reclassified to the consolidated statements of operations in the periods in which those respective derivative contracts settle. Prior to discontinuance of hedge accounting, the fair value of these commodity derivative instruments was recognized in accumulated other comprehensive income (loss) within partners' capital on the Partnership's consolidated balance sheets and reclassified to the Partnership's consolidated statements of operations at the time the originally hedged physical transactions affected earnings.

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.

Partnership Preferred Units

The following is a summary of recent Partnership Preferred Unit activity:

- In connection with the Partnership's acquisition of Titan Operating, L.L.C. in July 2012, the Partnership issued 3.8 million convertible Class B Partnership preferred units ("Class B Preferred Units"). While outstanding, the Class B Preferred Units received quarterly cash distributions equal to the greater of (i) $0.40 and (ii) the quarterly common unit distribution.

    - On December 23, 2014, 3,796,900 of Class B Preferred Units were voluntarily converted into common units, while the remaining 39,654 Class B Preferred Units were converted into common units on July 25, 2015.

- In connection with the Partnership's acquisition of certain proved reserves and associated assets from EP Energy, Inc. in July 2013, the Partnership issued 3.7 million convertible Class C Partnership Preferred Units to Atlas Energy ("Class C Preferred Units"). The Class C Preferred Units receive quarterly cash distributions equal to the greater of (i) $0.51 and (ii) the quarterly common unit distribution.

- In October 2014, in connection with the Partnership's acquisition of assets in the Eagle Ford Shale (see Note 3), the Partnership issued 3.2 million of its 8.625% Class D cumulative redeemable perpetual preferred units ("Class D Preferred Units") and in March 2015, issued an additional 800,000 Class D Preferred Units (see Note 12). The Partnership pays quarterly distributions on the Class D Preferred Units at an annual rate of $2.15625 per unit, or 8.625% of the $25.00 liquidation preference.

- In April 2015, the Partnership issued 255,000 of its 10.75% Class E cumulative redeemable perpetual preferred units ("Class E Preferred Units"). The initial quarterly distribution on the Class E Preferred Units was $0.6793 per unit, representing the distribution for the period from April 14, 2015 through July 15, 2015. Subsequent to July 15, 2015, the Partnership pays future quarterly distributions on the Class E Preferred Units at an annual rate of $2.6875 per unit, or 10.75% of the liquidation preference.

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, 2015 and 2014.

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 2011. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of

September 30, 2015.

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.

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 income (loss) attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net income (loss)	$(560,854)	$1,885	$(520,092)	$(27,558)
Preferred limited partner dividends	(4,293)	(4,475)	(12,180)	(13,298)
Net loss attributable to common limited partners and the general partner	(565,147)	(2,590)	(532,272)	(40,856)
Less: General partner's interest	11,303	(3,009)	10,645	(7,427)
Net loss attributable to common limited partners	(553,844)	(5,599)	(521,627)	(48,283)
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 - Basic	(553,844)	(5,599)	(521,627)	(48,283)
Plus: Convertible preferred limited partner dividends(1)	—	—	—	—
Net loss utilized in the calculation of net loss attributable to common limited partners per unit - Diluted	$(553,844)	$(5,599)	$(521,627)	$(48,283)

(1) Net income (loss) 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 and nine months ended September 30, 2015, net loss attributable to common limited partners' ownership interest is not allocated to approximately 346,000

and 501,000 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 three and nine months ended September 30, 2014, net loss attributable to common limited partners' ownership interest is not allocated to approximately 797,000 and 780,000 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 three and nine months ended September 30, 2015 and 2014, distributions on the Partnership's Class B and Class C preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

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 or if converted methods, as applicable. 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,	
	2015	2014	2015	2014
Weighted average number of common limited partner units—basic	96,660	81,521	90,943	72,288
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	96,660	81,521	90,943	72,288

(1) For the three and nine months ended September 30, 2015, 346,000 and 501,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the three and nine months ended September 30, 2014, approximately 797,000 and 780,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

(2) For the three and nine months ended September 30, 2014 and the three and nine months ended September 30, 2015, potential common limited partner units issuable upon conversion of the Partnership's Class B preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. For the three and nine months ended September 30, 2014 and the three and nine months ended September 30, 2015, potential common limited partner units issuable upon (a) conversion of the Partnership's Class C preferred units and (b) exercise of the common unit 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. As the Class D and Class E preferred units are convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

Revenue Recognition

Natural gas and oil production. 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.

Drilling Partnerships. Certain energy activities are conducted by the Partnership through, and a portion of its revenues are attributable to, sponsorship of the Drilling Partnerships. Drilling Partnership investor capital raised by the Partnership is deployed to drill and complete wells included within the partnership. As the Partnership deploys Drilling Partnership investor capital, it recognizes certain management fees it is entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if the Partnership has Drilling Partnership investor capital that has not yet been deployed, it will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on the Partnership's consolidated balance sheets. After the Drilling Partnership well is completed and turned in line (i.e. wells that have been drilled, completed, and connected to a gathering system), the Partnership is entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees it is entitled to receive for services provided, the Partnership is also entitled to its pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%. The Partnership recognizes its Drilling Partnership management fees in the following manner:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, the Partnership receives a 15% mark-up on those costs incurred to drill and complete wells included within the partnership. Such fees are earned, in accordance with each Drilling Partnership's partnership agreement, and recognized as the services are performed, typically between 60 and 270 days.
- Administration and oversight. For each well drilled by a Drilling Partnership, the Partnership receives a fixed fee between $100,000 and $500,000, depending on the type of well drilled, which is earned in accordance with each Drilling Partnership's partnership agreement and recognized at the initiation of the well. Additionally, the

Drilling Partnership pays the Partnership a monthly per well administrative fee of $75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed.

- Well services. Each Drilling Partnership pays the Partnership a monthly per well operating fee, currently $1,000 to $2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

While the historical structure has varied, the Partnership has generally agreed to subordinate a portion of its share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of cumulative unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. The Partnership periodically compares the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, the Partnership recognizes subordination as an estimated reduction of its pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which the Partnership has recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

Gathering and processing revenue. Gathering and processing revenue includes gathering fees the Partnership charges to the Drilling Partnership wells for the Partnership’s processing plants in the New Albany and the Chattanooga Shales. Generally, the Partnership charges a gathering fee to the Drilling Partnership wells equivalent to the fees the Partnership remits. In Appalachia, a majority of the Drilling Partnership wells are subject to a gathering agreement, whereby the Partnership remits a gathering fee of 16%. However, based on the respective Drilling Partnership partnership agreements, the Partnership charges the Drilling Partnership wells a 13% gathering fee. As a result, some of the Partnership’s gathering expenses, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

The Partnership’s gas and oil production operations accrue 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 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, 2015 and December 31, 2014 of $46.3 million and $84.7 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 for all periods presented, only include changes in the fair value of unsettled derivative contracts accounted for as cash flow hedges (see Note 8). The Partnership does not have any other type of transaction which would be included within other comprehensive income (loss).

Recently Issued Accounting Standards

In September 2015, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2015-16, Business Combinations (Subtopic 805) ("Update 2015-16")which eliminates the need to retrospectively adjust previously issued financial statements for changes in provisional amounts recognized at the date on which a business was acquired and later revised based on new information about facts and circumstances that existed at the acquisition date. Subsequent to the effective date of this accounting standard, such adjustments will be applied prospectively and the nature of, and reason for, the change in accounting principle will be disclosed. The Partnership will adopt the requirements of Update 2015-16 upon its effective date of January 1, 2016, and the Partnership does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In August 2015, the FASB issued ASU 2015-15, Interest—Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements which was a clarification of its previously issued ASU 2015-03, Interest—Imputation of Interest (“Update 2015-15”)requiring entities to present debt issuance costs related to a recognized debt liability as a direct deduction from the carrying amount of that debt liability. Given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to line-of-credit arrangements, ASU 2015-15 effectively allows an entity to defer line-of-credit issuance costs and present such costs as an asset. These deferred debt issuance costs may be amortized ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Partnership will adopt the requirements of Update 2015-15 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In April 2015, the FASB issued ASU 2015-06, Earnings Per Share (Topic 260): Effects on Historical Earnings per Unit of Master Limited Partnership Dropdown Transactions (“Update 2015-06”). Under Topic 260, Earnings per Share, master limited partnerships (“MLPs”) apply the two-class method to calculate earnings per unit (“EPU”) because the general partner, limited partners, and incentive distribution rights holders each participate differently in the distribution of available cash. When a general partner transfers (or “drops down”) net assets to an MLP and that transaction is accounted for as a transaction between entities under common control, the statements of operations of the MLP are adjusted retrospectively to reflect the drop down transaction as if it occurred on the earliest date during which the entities were under common control. The amendments in Update 2015-06 specify that for purposes of calculating historical EPU under the two-class method, the earnings (losses) of a transferred business before the date of a drop down transaction should be allocated entirely to the general partner interest, and previously reported EPU of the limited partners would not change as a result of a drop down transaction. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs also are required. The amendments in Update 2015-06 are effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption is permitted and amendments in Update 2015-06 should be applied retrospectively for all financial statements presented. The Partnership will adopt the requirements of Update 2015-06 upon its effective date of January 1, 2016, and the Partnership does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In March 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30) (“Update 2015-03”). The amendments in Update 2015-03 are intended to simplify presentation of debt issuance costs and require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs would not be affected by the amendments in Update 2015-03. The amendments in Update 2015-03 are effective for periods beginning after December 15, 2015, and interim periods within those periods. Early adoption is permitted, including adoption in an interim period, and an entity should apply the new guidance on a retrospective basis. The Partnership will adopt the requirements of Update 2015-03 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis (“Update 2015-02”). The amendments in Update 2015-02 are intended to improve targeted areas of consolidation guidance for legal entities such as limited partnerships, limited liability corporations and securitization structures. The amendments simplify the consolidation evaluation for reporting organizations that are required to evaluate whether they should consolidate certain legal entities. The amendments in Update 2015-02 are effective for periods beginning after December 31, 2015. Early adoption is permitted, including adoption in an interim period. The Partnership will adopt the requirements of Update 2015-02 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In January 2015, the FASB issued ASU 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items (“Update 2015-01”). The amendments in Update 2015-01 simplify the income statement presentation requirements in Subtopic 225-20 by eliminating the concept of extraordinary items. Extraordinary items are events and transactions that are distinguished by their unusual nature and by the infrequency of their occurrence. The amendments in Update 2015-01 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. A reporting entity may apply the amendments prospectively. A reporting entity may also apply the amendments retrospectively to all prior periods presented in the financial statements. Early adoption is permitted provided that the guidance is applied from the beginning of the fiscal year of adoption. The Partnership will adopt the requirements of Update 2015-01 upon its effective date of January 1, 2016, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In November 2014, the FASB issued ASU 2014-16, Derivatives and Hedging (Topic 815) – Determining Whether the Host Contract in a Hybrid Financial Instrument Issued in the Form of a Share is More Akin to Debt or to Equity ("Update 2014-16"). Certain classes of shares include features that entitle the holders to preferences and rights (such as conversion rights, redemption rights, voting powers, and liquidation and dividend payment preferences) over the other shareholders. Shares that include embedded derivative features are referred to as hybrid financial instruments, which must be separated from the host contract and accounted for as a derivative if certain criteria are met under Subtopic 815-10. One criterion requires evaluating whether the nature of the host contract is more akin to debt or to equity and whether the economic characteristics and risks of the embedded derivative feature are "clearly and closely related" to the host contract. In making that evaluation, an issuer or investor may consider all terms and features in a hybrid financial instrument including the embedded derivative feature that is being evaluated for separate accounting or may consider all terms and features in the hybrid financial instrument except for the embedded derivative feature that is being evaluated for separate accounting. The use of different methods can result in different accounting outcomes for economically similar hybrid financial instruments. Additionally, there is diversity in practice with respect to the consideration of redemption features in relation to other features when determining whether the nature of a host contract is more akin to debt or to equity. The amendments in Update 2014-16 clarify how current U.S. GAAP should be interpreted in evaluating the economic characteristics and risks of a host contract in a hybrid financial instrument that is issued in the form of a share. The effects of initially adopting the amendments in Update 2014-16 should be applied on a modified retrospective basis to existing hybrid financial instruments issued in the form of a share as of the beginning of the fiscal year for which the amendments are effective. Retrospective application is permitted to all relevant prior periods. The amendments in Update 2014-16 are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Early adoption, including adoption in an interim period, is permitted. The Partnership will adopt the requirements of Update 2014-16 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40) ("Update 2014-15"). The amendments in Update 2014-15 provide U.S. GAAP guidance on the responsibility of an entity's management in evaluating whether there is substantial doubt about the entity's ability to continue as a going concern and about related footnote disclosures. For each reporting period, an entity's management will be required to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued. In doing so, the amendments in Update 2014-15 should reduce diversity in the timing and content of footnote disclosures. The amendments in Update 2014-15 are effective for the annual period ending after December 15, 2016, and for annual and interim periods thereafter. Early adoption is permitted. The Partnership will adopt the requirements of Update 2014-15 upon its effective date in 2016, and it does not anticipate it having a material impact on its financial position, results of operations or related disclosures.

In June 2014, the FASB issued ASU 2014-12, Compensation – Stock Compensation (Topic 718) ("Update 2014-12"). The amendments in Update 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period, be treated as a performance condition. As such, the performance target should not be reflected in estimating the grant date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. The amendments in Update 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted. Entities may apply the amendments in

Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The Partnership will adopt the requirements of Update 2014-12 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606) ("Update 2014-09"), which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, Property, Plant and Equipment, and intangible assets within the scope of Topic 350, Intangibles – Goodwill and Other) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. Early adoption is not permitted. The Partnership will adopt the requirements of Update 2014-09 retrospectively upon its effective date of January 1, 2018, and is evaluating the impact of the adoption on its financial position, results of operations or related disclosures.

NOTE 3 – ACQUISITIONS

Rangely Acquisition

On June 30, 2014, the Partnership completed an acquisition of a 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado from Merit Management Partners I, L.P., Merit Energy Partners III, L.P. and Merit Energy Company, LLC (collectively, “Merit Energy”) for approximately $408.9 million in cash, net of purchase price adjustments (the “Rangely Acquisition”). The purchase price was funded through borrowings under the Partnership’s revolving credit facility, the issuance of an additional $100.0 million of its 7.75% senior notes due 2021 (“7.75% Senior Notes”) (see Note 7) and the issuance of 15,525,000 common limited partner units (see Note 12). The Rangely Acquisition had an effective date of April 1, 2014. The Partnership’s consolidated financial statements reflected the operating results of the acquired business commencing June 30, 2014 with the transaction closing.

The Partnership accounted for this transaction under the acquisition method of accounting. Accordingly, the Partnership evaluated the identifiable assets acquired and liabilities assumed at their respective acquisition date fair values (see Note 9). In conjunction with the issuance of common limited partner units associated with the acquisition, the Partnership recorded $11.6 million of transaction fees, which were included with common limited partners’ interests for the year ended December 31, 2014 on the Partnership’s consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred.

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:	
Prepaid expenses and other	$4,041
Property, plant and equipment	405,416
Other assets, net	2,888
Total assets acquired	$412,345
Liabilities:	
Accrued liabilities	2,117
Asset retirement obligation	1,305
Total liabilities assumed	3,422

Net assets acquired	$408,923

Other Acquisitions

Arkoma Acquisition

On June 5, 2015, the Partnership completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). The Partnership funded the purchase price through the issuance of 6,500,000 common limited partner units (see Note 12). The Arkoma Acquisition had an effective date of January 1, 2015. The Partnership accounted for the Arkoma Acquisition as a transaction between entities under common control (see Note 2).

Eagle Ford Acquisition

On November 5, 2014, the Partnership and AGP completed an acquisition of oil and natural gas liquid interests in the Eagle Ford Shale in Atascosa County, Texas from Cima Resources, LLC and Cinco Resources, Inc. (together "Cinco") for $342.0 million, net of purchase price adjustments (the "Eagle Ford Acquisition"). Approximately $183.1 million was paid in cash by the Partnership and $19.9 million was paid by AGP at closing, and approximately $139.0 million was to be paid in four quarterly installments beginning December 31, 2014. On December 31, 2014, AGP made its first installment payment of $35.0 million related to its Eagle Ford Acquisition. Prior to the March 31, 2015 installment, the Partnership, AGP, and Cinco amended the purchase and sale agreement to alter the timing and amount of the quarterly payments beginning with the March 31, 2015 payment and ending December 31, 2015, with no change to the overall purchase price. On March 31, 2015, AGP paid $28.3 million and the Partnership issued $20.0 million of its Class D Preferred Units (see Note 12) to satisfy the second installment related to the Eagle Ford Acquisition. On June 30, 2015, AGP paid $16.0 million and the Partnership paid $0.6 million to satisfy the third installment related to the Eagle Ford Acquisition. In September 2015, the Partnership agreed with AGP to have AGP transfer its remaining $36.3 million of deferred purchase obligation, along with the related undeveloped natural gas and oil properties, to the Partnership. On September 30, 2015 the Partnership paid $17.5 million to satisfy the fourth installment related to the Eagle Ford Acquisition. At September 30, 2015, the Partnership's remaining deferred portion of the purchase price was $21.6 million, payable on December 31, 2015. The Partnership's issuance of Class D Preferred Units represents a non-cash transaction for statement of cash flow purposes during the nine months ended September 30, 2015.

GeoMet Acquisition

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. ("GeoMet") (OTCQB: GMET) for approximately $97.9 million in cash, net of purchase price adjustments, with an effective date of January 1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	September 30, 2015	December 31, 2014	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$ 456,181	$ 441,548	
Pre-development costs	8,167	7,223	
Wells and related equipment	3,081,614	3,026,416	
Total proved properties	3,545,962	3,475,187	
Unproved properties	264,844	217,321	
Support equipment	44,260	37,359	
Total natural gas and oil properties	3,855,066	3,729,867	
Pipelines, processing and compression facilities	56,632	49,547	2 – 40
Rights of way	829	830	20 – 40
Land, buildings and improvements	9,202	9,160	3 – 40
Other	18,316	17,936	3 – 10
	3,940,045	3,807,340	
Less – accumulated depreciation, depletion and amortization	(2,405,327)	(1,543,520)	
	$ 1,534,718	$ 2,263,820	

During the three and nine months ended September 30, 2015, the Partnership recognized a $0.4 million and a $0.3 million loss, respectively, on asset sales and disposals. During the nine months ended September 30, 2014, the Partnership recognized $1.7 million of loss on asset sales and disposals primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement.

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, 2015 and 2014.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. For the three and nine months ended September 30, 2015, the Partnership recognized $740.2 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Southern

Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, reduced by $68.0 million of future hedge gains reclassified from accumulated other comprehensive income. Asset impairment and the related hedge gains are included in Asset impairment expense in the Partnership's combined consolidated results of operations. There were no impairments of proved gas and oil properties for the three and nine months ended September 30, 2014.

During the nine months ended September 30, 2015 and 2014, the Partnership recognized $5.2 million and $42.5 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on the Partnership's consolidated statements of cash flows.

NOTE 5 – OTHER ASSETS

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

	September 30, 2015	December 31, 2014
Deferred financing costs, net of accumulated amortization of $31,774 and $18,622 at September 30, 2015 and December 31, 2014, respectively	$ 44,571	$ 40,637
Notes receivable	3,871	3,866
Other	5,384	5,578
	$ 53,826	$ 50,081

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 $3.2 million and $2.4 million for the three months ended September 30, 2015 and 2014, respectively, and $8.9 million and $6.1 million for the nine months ended September 30, 2015 and 2014, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the nine months ended September 30, 2015, the Partnership recognized $4.3 million for accelerated amortization of deferred financing costs associated with a reduction of the borrowing base under the revolving credit facility. There was no accelerated amortization of deferred financing costs for the Partnership during the three months ended September 30, 2015 and 2014 and the nine months ended September 30, 2014.

At September 30, 2015 and December 31, 2014, 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 sheets. 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 months ended September 30, 2015 and 2014, approximately $21,000 and $22,000, respectively, of interest income was recognized within other, net on the Partnership's consolidated statements of operations, and approximately $64,000 and $68,000 for the nine months ended September 30, 2015 and 2014, respectively. At September 30, 2015 and December 31, 2014, the Partnership recorded no allowance for credit losses within its consolidated balance sheets based upon payment history and ongoing credit evaluations associated with the notes receivable.

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 where 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 for asset retirement obligations was based on the Partnership's historical experience in plugging and abandoning wells, the 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, 2015, the Drilling Partnerships had $45.6 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. As of September 30, 2015, the Partnership has withheld $4.3 million of limited partner distributions related to the asset retirement obligations of certain Drilling Partnerships. 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,	
	2015	2014	2015	2014
Asset retirement obligations, beginning of period	$110,775	$101,325	$107,950	$91,179
Liabilities incurred	80	323	292	8,178
Liabilities settled	(1)	(271)	(547)	(820)
Accretion expense	1,581	1,468	4,740	4,308
Asset retirement obligations, end of period	$112,435	$102,845	$112,435	$102,845

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations. During the year ended December 31, 2014, the Partnership incurred $7.0 million of future plugging and abandonment costs related to acquisitions it consummated (see Note 3). During the nine months ended September 30, 2014, the Partnership incurred $6.6 million of future plugging and abandonment liabilities within purchase accounting for the Rangely and GeoMet acquisitions it consummated during the period (see Note 3). No future plugging and abandonment liabilities related to consummated acquisitions were incurred during the three and nine months ended September 30, 2015.

NOTE 7 - DEBT

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

	September 30, 2015	December 31, 2014
Revolving credit facility	$563,000	$696,000
Term loan facility	243,408	—
7.75 % Senior Notes – due 2021	374,601	374,544
9.25 % Senior Notes – due 2021	324,038	323,916
Total debt	1,505,047	1,394,460
Less current maturities	—	—
Total long-term debt	$1,505,047	$1,394,460

Credit Facility

The Partnership is a party to its Second Amended and Restated Credit Agreement dated July 31, 2013, as amended, with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the "Credit Agreement"), which provides for a senior secured revolving credit facility with a borrowing base of $750.0 million as of September 30, 2015.

The Partnership's borrowing base is scheduled for semi-annual redeterminations in November 2015 and thereafter in May and November of each year. In July 2015, a determination by the lenders reaffirmed the Partnership's $750.0 million borrowing base. The Credit Agreement also provides that the Partnership's borrowing base will be reduced by 25% of the stated amount of any senior notes issued, or additional second lien debt incurred, after July 1, 2015. At September 30, 2015, $563.0 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 $4.3 million was outstanding at September 30, 2015. 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 non-guarantor subsidiaries of the Partnership are minor. Borrowings under the credit facility bear interest, at the Partnership's election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% 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 0.50% and 1.75% per annum. If the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, the applicable margin on Eurodollar loans and ABR loans will be increased by 0.25%. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on the Partnership's consolidated statements of operations. At September 30, 2015, the weighted average interest rate on outstanding borrowings under the credit facility was 2.75%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness (excluding second lien debt in an aggregate principal amount of up to $300.0 million), 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, 2015. The Credit Agreement also requires the Partnership to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter 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, 2015, the Partnership's ratio of current assets to current liabilities was 1.4 to 1.0, and its ratio of Total Funded Debt to EBITDA was 5.2 to 1.0.

Term Loan Facility

On February 23, 2015, the Partnership entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020. The Term Loan Facility is presented net of unamortized discount of $6.6 million at September 30, 2015.

The Partnership has the option to prepay the Term Loan Facility at any time, and is required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. The Partnership is also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;

- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

The Partnership’s obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of its assets and those of its restricted subsidiaries (the “Loan Parties”) that guarantee the Partnership’s existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by the Partnership’s material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at the Partnership’s option, at either

(i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an “ABR Loan”). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans. At September 30, 2015, the weighted average interest rate on outstanding borrowings under the term loan facility was 10.0%.

The Second Lien Credit Agreement contains customary covenants that limit the Partnership’s ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in the Partnership’s existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. The Partnership was in compliance with these covenants as of September 30, 2015.

Under the Second Lien Credit Agreement, the Partnership may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed $300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

Senior Notes

At September 30, 2015, the Partnership had $374.6 million outstanding of its 7.75% senior unsecured notes due 2021 (“7.75% Senior Notes”). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of September 30, 2015. 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 for 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 Partnership may redeem the 7.75% Senior Notes in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (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. 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 7.75% Senior Notes.

At September 30, 2015, the Partnership had $324.0 million outstanding of its 9.25% senior unsecured notes due 2021 (“9.25% Senior Notes”). The 9.25% Senior Notes were presented net of a $1.0 million unamortized discount as of September 30, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, the Partnership may redeem the 9.25% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest, if any. 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%. 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.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of the Partnership’s material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% 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% Senior Notes 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, 2015.

Total cash payments for interest by the Partnership were $87.7 million and $55.2 million for the nine months ended September 30, 2015 and 2014, 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. To manage the risk of regional commodity price differences, the Partnership occasionally enters into basis swaps. Basis swaps are contractual arrangements that guarantee a price differential for a commodity from a specified delivery point price and the comparable national exchange price. For natural gas basis swaps, which have negative differentials to the New York Mercantile Stock Exchange (“NYMEX”), the Partnership receives or pays a payment from the counterparty if the price differential to NYMEX is greater or less than the stated terms of the contract. 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.

On January 1, 2015, the Partnership discontinued hedge accounting for its qualified commodity derivatives. As such, changes in fair value of these derivatives after December 31, 2014 are recognized immediately within gain (loss) on mark-to-market derivatives in the Partnership’s consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners’ capital on the Partnership’s consolidated balance sheet, are being reclassified to the Partnership’s consolidated statements of operations at the time the originally hedged physical transactions settle.

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 recorded net derivative assets of $352.6 million and $274.9 million on its consolidated balance sheets at September 30, 2015 and December 31, 2014, respectively. Of the $46.4 million of deferred gains in accumulated other comprehensive income on the Partnership’s consolidated balance sheet at September 30, 2015, the Partnership will reclassify $27.7 million of gains to its consolidated statement of operations over the next twelve month period as these contracts expire with the remaining gains of $18.7 million being reclassified to the Partnership’s consolidated statements of operations in later periods as the remaining contracts expire.

The following table summarizes the commodity derivative activity for the three and nine months ended September 30, 2015 (in thousands):

	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2015
	$ (23,927)	$ (77,048)

Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets[1]		
Portion of settlements attributable to subsequent mark to market gains	(19,555)	(49,680)
Total cash settlements on commodity derivative contracts	(43,482)	(126,728)
2015 Unrealized gains prior to settlement[2]	10,426	17,259
Unrealized gain on open derivative contracts at September 30, 2015, net of amounts recognized in income in prior year[2]	120,639	192,447
Gains on mark-to-market derivatives	$ 131,065	$ 209,706

(1) Recognized in gas and oil production revenue.
(2) Recognized in gain on mark-to-market derivatives.

The Partnership had gains of $43.5 million and $1.4 million related to cash settlements during the three months ended September 30, 2015 and 2014, respectively, and a gain of $126.7 million and a loss of $22.7 million related to cash settlements during the nine months ended September 30, 2015 and 2014, respectively. 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, 2015 and 2014 for hedge ineffectiveness.

The following table summarizes the gross fair values of the Partnership's derivative instruments, presenting the impact of offsetting the derivative assets and liabilities included 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 of Assets Presented in the Consolidated Balance Sheets
As of September 30, 2015			
Current portion of derivative assets	$ 146,629	$ (7)	$ 146,622
Long-term portion of derivative assets	205,979	—	205,979
Total derivative assets	$ 352,608	$ (7)	$ 352,601
As of December 31, 2014			
Current portion of derivative assets	$ 144,357	$ (98)	$ 144,259
Long-term portion of derivative assets	130,972	(370)	130,602
Total derivative assets	$ 275,329	$ (468)	$ 274,861

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, 2015			
Current portion of derivative liabilities	$ (7)	$ 7	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ (7)	$ 7	$ —
As of December 31, 2014			
Current portion of derivative liabilities	$ (98)	$ 98	$ —
Long-term portion of derivative liabilities	(370)	370	—
Total derivative liabilities	$ (468)	$ 468	$ —

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 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, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price. These contracts were recorded at their fair values.

At September 30, 2015, 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)
2015	13,611,100	$ 4.193	$ 21,734
2016	53,546,300	$ 4.229	75,852
2017	49,920,000	$ 4.219	60,364
2018	40,800,000	$ 4.170	44,298
2019	15,960,000	$ 4.017	13,785
			$ 216,033

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)	Fair Value Asset (in thousands)(2)
2015	Puts purchased	600,000	$ 3.934	$ 803
2015	Calls sold	600,000	$ 4.634	—
				$ 803

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)
2015	Puts purchased	360,000	$ 4.000	$ 505
2016	Puts purchased	1,440,000	$ 4.150	1,952
				$ 2,457

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Asset (in thousands)(7)
2015	1,200,000	$ (0.090)	$ 41
			$ 41

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)	Fair Value Asset (in thousands)(8)
2015	1,260,000	$ 1.923	$ 1,225

			$ 1,225

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[(1)]	Average Fixed Price (per Gal)[(1)]	Fair Value Asset (in thousands)[(4)]
2015	2,016,000	$ 1.016	$ 1,096
			$ 1,096

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[(1)]	Average Fixed Price (per Gal)[(1)]	Fair Value Asset (in thousands)[(5)]
2015	378,000	$ 1.248	$ 237
			$ 237

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Asset (in thousands)[6]
2015	378,000	$ 1.263	$ 238
			$ 238

Natural Gas Liquids – Crude Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Asset (in thousands)[3]
2016	84,000	$ 85.651	$ 3,038
2017	60,000	$ 83.780	1,828
			$ 4,866

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Asset (in thousands)[3]
2015	487,500	$87.592	$ 20,377
2016	1,557,000	$81.471	49,856
2017	1,140,000	$77.285	27,462
2018	1,080,000	$76.281	22,073
2019	540,000	$68.371	5,837
			$ 125,605
		Total net assets	$ 352,601

(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 propane prices, as applicable.
(5) Fair value based on forward Mt. Belvieu butane prices, as applicable.

(6) Fair value based on forward Mt. Belvieu iso butane prices, as applicable.
(7) Fair value based on forward WAHA natural gas prices, as applicable
(8) Fair value based on forward Mt. Belvieu natural gasoline prices, as applicable.
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, 2015, net unrealized derivative assets of $2.5 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At September 30, 2015, 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 the ultimate 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, 2015 and December 31, 2014 was as follows (in thousands):

As of September 30, 2015	Level 1	Level 2	Level 3	Total
Derivative assets, gross				
Commodity swaps	$ —	$349,348	$ —	$349,348
Commodity puts	—	2,457	—	2,457
Commodity options	—	803	—	803
Total derivative assets, gross	—	352,608	—	352,608
Derivative liabilities, gross				
Commodity swaps	—	(7)	—	(7)

Commodity options		—	—	—	—
Total derivative liabilities, gross		—	(7)	—	(7)
Total derivatives, fair value, net	$	—	$352,601	$ —	$352,601

As of December 31, 2014	Level 1		Level 2	Level 3	Total
Derivative assets, gross					
Commodity swaps	$	—	$267,242	$ —	$267,242
Commodity puts		—	2,767	—	2,767
Commodity options		—	5,320	—	5,320
Total derivative assets, gross		—	275,329	—	275,329
Derivative liabilities, gross					
Commodity swaps		—	(401)	—	(401)
Commodity options		—	(67)	—	(67)
Total derivative liabilities, gross		—	(468)	—	(468)
Total derivatives, fair value, net	$	—	$274,861	$ —	$274,861

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 values of the Partnership's long-term debt at September 30, 2015 and December 31, 2014, which consist of its Senior Notes and outstanding borrowings under its revolving credit and term loan facilities (see Note 7), were $1,049.5 million and $1,219.8 million, respectively, compared with the carrying amounts of $1,505.0 million and $1,394.5 million, respectively. At September 30, 2015 and December 31 2014, the carrying values of outstanding borrowings under the Partnership's respective revolving and term loan credit facilities (see Note 7), which bear interest at variable interest rates, approximated their estimated fair values. The estimated fair values of the Partnership's Senior Notes were based upon the market approach and calculated using yields of the Partnership Senior Notes as provided by financial institutions and thus were categorized as Level 3 values.

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

Management estimates the fair value of the Partnership's 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 asset retirement obligations that were measured at fair value on a nonrecurring basis for the three and nine months September 30, 2015 and 2014 were as follows (in thousands):

	Three Months Ended September 30,			
	2015		2014	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$80	$ 80	$323	$323
Total	$80	$ 80	$323	$323

	Nine Months Ended September 30,			
	2015		2014	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$292	$292	$8,178	$8,178
Total	$292	$292	$8,178	$8,178

Management estimates the fair value of the Partnership's long-lived assets in connection with reviewing these assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions and judgments regarding such events or circumstances. See Note 4 for a discussion of current year impairments. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs. No impairments were recognized during the three and nine months ended September 30, 2014.

During the year ended December 31, 2014, the Partnership completed the Eagle Ford, Rangely and GeoMet acquisitions (see Note 3). The fair value measurements of assets acquired and liabilities assumed for these acquisitions are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The estimated fair values of the assets acquired and liabilities assumed in the Eagle Ford Acquisition as of the acquisition date, which are reflected in the Partnership's consolidated balance sheet as of September 30, 2015, are subject to change as the final valuation has not yet been completed, and such changes could be material. 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 valuations and are subject to change.

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, sponsorship of 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.

NOTE 11 — COMMITMENTS AND CONTINGENCIES

General Commitments

The Partnership is the ultimate 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. The Partnership has structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, the Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and the Partnership may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that it does not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by the Partnership to reflect current well performance, commodity prices and production costs, among other items. Based on its historical experience, as of September 30, 2015, the management of the Partnership believes that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While its historical structure has varied, the Partnership has generally agreed to subordinate a portion of its share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. The Partnership periodically compares the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, the Partnership recognizes subordination as an estimated reduction of its pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which the Partnership has recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, the Partnership will recognize an estimated increase in its portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized. For the three months ended September 30, 2015 and 2014, $0.4 million and $0.9 million, respectively, of the Partnership's gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses. For the nine months ended September 30, 2015 and 2014, $1.5 million and $4.7 million, respectively, of the Partnership's gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

In connection with the Eagle Ford Acquisition (see Note 3), the Partnership guaranteed the timely payment of the deferred portion of the purchase price that was to be paid by AGP. The Partnership's deferred purchase obligation is included within accrued liabilities on the Partnership's consolidated balance sheets at September 30, 2015 and December 31, 2014.

In connection with the GeoMet Acquisition (see Note 3), the Partnership acquired certain long-term annual firm transportation obligations. Estimated fixed and determinable portions of the Partnership's firm transportation obligations as of September 30, 2015 were as follows: 2015— $0.9 million; 2016— $3.6 million; 2017— $2.5 million; 2018— $1.8 million; 2019— $1.8 million; thereafter— $6.5 million.

In connection with the Partnership's acquisition of assets from EP Energy E&P Company, L.P. on July 31, 2013 (the "EP Energy Acquisition"), the Partnership acquired certain long-term annual firm transportation obligations. Estimated fixed and determinable portions of the Partnership's firm transportation obligations as of September 30, 2015 were as follows: 2015— $2.2 million; 2016— $2.2 million; and 2017 to 2019— none.

As of September 30, 2015, the Partnership is committed to expend approximately $45.0 million, principally on drilling and completion expenditures.

Legal Proceedings

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

NOTE 12 –ISSUANCES OF UNITS

In August 2015, the Partnership entered into a distribution agreement with MLV & Co. LLC ("MLV"). Pursuant to the distribution agreement, the Partnership may sell from time to time through MLV the Partnership's 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") having a maximum aggregate offering price of up to $100 million. Sales of Class D and Class E Preferred 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 NYSE, the existing trading market for the 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 MLV a commission, which shall not be more than 3.0% of the gross sales price of Class D and Class E Preferred Units. The Partnership has agreed to reimburse MLV for certain expenses incurred in connection with entering into the distribution agreement. Under the terms of the distribution agreement, the Partnership may also sell Class D and Class E Preferred Units from time to time to MLV as principal for its own account at a price to be agreed upon at the time of sale. Any sale of Class D and Class E Preferred Units to MLV as principal would be pursuant to the terms of a separate terms agreement between the Partnership and MLV. During the three and nine months ended September 30, 2015, the Partnership issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units under the preferred equity distribution program for net proceeds of $1.0 million, net of $0.2 million in commissions and offering expenses paid.

In May 2015, in connection with the Arkoma Acquisition (see Note 3), the Partnership issued 6,500,000 of its common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.7 million. The Partnership used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under the Partnership's revolving credit facility.

In April 2015, the Partnership issued 255,000 of its Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. The Partnership pays cumulative distributions on a quarterly basis at an annual rate of $2.6875 per unit or at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

In October 2014, in connection with the Eagle Ford Acquisition (see Note 3), the Partnership issued 3,200,000 8.625% Class D Preferred Units at a public offering price of $25.00 per Class D Preferred Unit, yielding net proceeds of approximately $77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. The Partnership used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition. On

March 31, 2015, to partially pay its portion of the quarterly installment related to the Eagle Ford Acquisition, the Partnership issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit. On January 15, 2015, the Partnership paid an initial quarterly distribution of $0.616927 per unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015 (see Note 13). The Partnership pays distributions on a quarterly basis, at an annual rate of $2.15625 per unit, or 8.625% of the $25.00 liquidation preference.

The Class D and Class E Preferred Units rank senior to the Partnership's common units and Class C Preferred Units with respect to the payment of distributions and distributions upon a liquidation event. The Class D and Class E Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change in control. At any time on or after October 15, 2019 for the Class D Preferred Units and April 15, 2020 for the Class E Preferred Units, the Partnership may, at its option, redeem such preferred units in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership may redeem such preferred units following certain changes of control, as described in the respective Certificates of Designation. If the Partnership does not exercise this redemption option upon a change of control, then holders of such preferred units will have the option to convert the preferred units into a number of

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Partnership common units as set forth in the respective Certificates of Designation. If the Partnership exercises any of its redemption rights relating to the preferred units, the holders of such preferred units will not have the conversion right described above with respect to the preferred units called for redemption.

In August 2014, the Partnership entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the “Agents”). Pursuant to the equity distribution agreement, the Partnership may sell from time to time through the Agents common units representing limited partner interests of the Partnership having an aggregate offering price of up to $100.0 million. Sales of common units 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, including sales made directly on the New York Stock Exchange, the existing trading market for the common 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 units sold through such Agent. Under the terms of the equity distribution agreement, the Partnership may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between the Partnership and such Agent. During the three months ended September 30, 2015, the Partnership issued 5,519,110 common limited partner units under the equity distribution program for net proceeds of $18.6 million, net of $0.3 million in commissions and offering expenses paid. During the nine months ended September 30, 2015, the Partnership issued 8,404,934 common limited partner units under the equity distribution program for net proceeds of $40.0 million, net of $1.0 million in commissions and offering expenses paid.

In May 2014, in connection with the Rangely Acquisition (see Note 3), the Partnership issued 15,525,000 of its common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.3 million.

In March 2014, in connection with the GeoMet Acquisition (see Note 3), the Partnership issued 6,325,000 of its common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.0 million.

NOTE 13 – CASH DISTRIBUTIONS

In January 2014, the Partnership’s board of directors approved the modification of its cash distribution payment practice to a monthly cash distribution program whereby it distributes all of its available cash (as defined in the partnership agreement) for that month to its unitholders within 45 days from the month end. Prior to that, the Partnership paid quarterly cash distributions within 45 days from the end of each calendar quarter. 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. While outstanding, the Class B Preferred Units received regular quarterly cash distributions equal to the greater of (i) $0.40 (or $0.1333 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. While outstanding, the Class C Preferred Units will receive regular quarterly cash distributions equal to the greater of (i) $0.51 (or $0.17 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. The initial quarterly distribution on the Class D Preferred Units was $0.616927 per unit, representing the distribution for the period from October 2, 2014 through January 14, 2015. The Partnership pays quarterly distributions on the Class D Preferred Units at an annual rate of $2.15625 per unit, $0.5390625 per unit paid on a quarterly basis, or 8.625% of the $25.00 liquidation preference. The Partnership pays quarterly distributions on the Class E Preferred Units at an annual rate of $2.6875 per unit, or $0.671875 per unit on a quarterly basis, or 10.75% of the $25.00 liquidation preference.

Distributions declared by the Partnership for the period from January 1, 2014 through September 30, 2015 were as follows (in thousands, except per unit amounts):

Date Cash Distribution Paid	For Month 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
March 17, 2014	January 31, 2014	$ 0.1933	$ 12,718	$ 1,467		$ 1,055
April 14, 2014	February 28, 2014	$ 0.1933	$ 12,719	$ 1,466		$ 1,055
May 15, 2014	March 31, 2014	$ 0.1933	$ 12,719	$ 1,466		$ 1,054
June 13, 2014	April 30, 2014	$ 0.1933	$ 15,752	$ 1,466		$ 1,279
July 15, 2014	May 31, 2014	$ 0.1933	$ 15,752	$ 1,466		$ 1,279
August 14, 2014	June 30, 2014	$ 0.1966	$ 16,029	$ 1,492		$ 1,377
September 12, 2014	July 31, 2014	$ 0.1966	$ 16,028	$ 1,493		$ 1,378
October 15, 2014	August 31, 2014	$ 0.1966	$ 16,032	$ 1,491		$ 1,378
November 14, 2014	September 30, 2014	$ 0.1966	$ 16,032	$ 1,492		$ 1,378
December 15, 2014	October 31, 2014	$ 0.1966	$ 16,033	$ 1,491		$ 1,378
January 14, 2015	November 30, 2014	$ 0.1966	$ 16,779	$ 745	(1)	$ 1,378
February 13, 2015	December 31, 2014	$ 0.1966	$ 16,782	$ 745	(1)	$ 1,378
March 17, 2015	January 31, 2015	$ 0.1083	$ 9,284	$ 643	(1)	$ 203
April 14, 2015	February 28, 2015	$ 0.1083	$ 9,347	$ 643	(1)	$ 204
May 15, 2015	March 31, 2015	$ 0.1083	$ 9,444	$ 643	(1)	$ 206
June 12, 2015	April 30, 2015	$ 0.1083	$ 10,179	$ 642	(1)	$ 221
July 15, 2015	May 31, 2015	$ 0.1083	$ 10,304	$ 643	(1)	$ 223
August 14, 2015	June 30, 2015	$ 0.1083	$ 10,309	$ 637	(2)	$ 223
September 14, 2015	July 31, 2015	$ 0.1083	$ 10,571	$ 638	(2)	$ 229
October 15, 2015	August 31, 2015	$ 0.1083	$ 10,949	$ 637	(2)	$ 236

(1) Includes payments for the Class B and Class C preferred unit monthly distributions.
(2) Includes payments for the Class C preferred unit monthly distributions.

Date Cash Distribution Paid	For the Period	Cash Distribution per Class D Preferred Limited Partner Unit	Total Cash Distribution To Class D Preferred Limited Partners
January 15, 2015	October 2, 2014 – January 14, 2015	$ 0.616927	$ 1,974
April 15, 2015		$ 0.539063	$ 2,156

	January 15, 2015 – April 14, 2015		
July 15, 2015	April 15, 2015 – July 14, 2015	$ 0.5390625	$ 2,157
October 15, 2015	July 15, 2015 – October 14, 2015	$ 0.5390625	$ 2,205

Date Cash Distribution Paid	For the Period	Cash Distribution per Class E Preferred Limited Partner Unit	Total Cash Distribution To Class E Preferred Limited Partners
July 15, 2015	April 14, 2015 – July 14, 2015	$ 0.6793	$ 173
October 15, 2015	July 15, 2015 – October 14, 2015	$ 0.6718750	$ 172

On October 28, 2015, the Partnership declared a monthly distribution of $0.1083 per common unit for the month of September 30, 2015. The $11.9 million distribution, including $0.2 million and $0.6 million to the general partner and preferred limited partners, respectively, will be paid on November 13, 2015 to unitholders of record at the close of business on November 9, 2015.

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, 2015, the Partnership had 1,736,920 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 182,008 phantom units, restricted units and unit options available for grant. Share based payments to non-employee directors, which have a cash settlement option, are recognized within liabilities in the consolidated financial statements based upon their current fair market value.

In the case of awards held by eligible employees, following a "change in control", as defined in the 2012 LTIP, 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. Upon a change in control, all unvested awards held by directors will immediately vest in full.

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 upon vesting. 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 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 four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at September 30, 2015, 162,496 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at September 30, 2015 include DERs. During the three months ended September 30, 2015 and 2014, the Partnership paid $0.1 million and $0.5 million, respectively, with respect to the 2012 LTIP's DERs. During the nine months ended September 30, 2015 and

2014, the Partnership paid $0.6 million and $1.5 million, respectively, with respect to the 2012 LTIP's DERs. These amounts were recorded as reductions of partners' capital on the Partnership's consolidated balance sheets.

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

	Three Months Ended September 30,			
	2015		2014	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of period	411,257	$ 21.10	901,207	$ 23.29
Granted	—	—	9,400	19.85
Vested and issued(1)	(68,187)	22.15	(115,797)	24.54
Forfeited	(23,914)	23.00	—	—
Outstanding, end of period(2)(3)	319,156	$ 20.74	794,810	$ 23.07
Vested and not yet issued(4)	3,125	$ 21.02	5,412	$ 25.25
Non-cash compensation expense recognized (in thousands)		$ 375		$ 1,647

	Nine Months Ended September 30,			
	2015		2014	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year	799,192	$ 22.70	839,808	$ 24.31
Granted	9,730	8.50	236,423	20.28
Vested and issued(1)	(457,727)	23.75	(262,671)	24.51
Forfeited	(32,039)	23.01	(18,750)	23.00
Outstanding, end of period(2)(3)	319,156	$ 20.74	794,810	$ 23.07
Vested and not yet issued(4)	3,125	$ 21.02	5,412	$ 25.25
Non-cash compensation expense recognized (in thousands)		$ 3,692		$ 4,968

(1) The intrinsic values of phantom unit awards vested and issued during the three months ended September 30, 2015 and 2014 were $0.3 million and $2.3 million, respectively, and $3.9 million and $5.2 million during the nine months ended September 30, 2015 and 2014, respectively.
(2) The aggregate intrinsic value for phantom unit awards outstanding at September 30, 2015 was $0.9 million.
(3) There were approximately $16,000 and $0.1 million recognized as liabilities on the Partnership's consolidated balance sheets at September 30, 2015 and December 31, 2014, respectively, representing 14,005 and 26,579 units, respectively, due to the option of the participants to settle in cash instead of units. The respective weighted average grant date fair values for these units were $13.39 and $21.16 at September 30, 2015 and December 31, 2014, respectively. There was $0.2 million recognized as liabilities on the Partnership's consolidated balance sheet at the period ended September 30, 2014 representing 29,035 units that participants may opt to settle in cash instead of units. The weighted average grant date fair value for these units was $21.09 at September 30, 2014.
(4)

The intrinsic values of phantom unit awards vested, but not yet issued at September 30, 2015 and 2014 were approximately $2,000 and $0.1 million, respectively.

At September 30, 2015, the Partnership had approximately $2.3 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 1.6 years.

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 83,163 unit options outstanding under the 2012 LTIP at September 30, 2015 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, 2015 and 2014.

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

	Three Months Ended September 30,			
	2015		2014	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of period	1,452,800	$ 24.66	1,468,925	$ 24.66
Granted	—	—	—	—
Exercised [1]	—	—	—	—
Forfeited	(35,036)	24.67	(3,750)	24.67
Outstanding, end of period[2][3]	1,417,764	$ 24.66	1,465,175	$ 24.66
Options exercisable, end of period[4]	1,332,976	$ 24.67	732,025	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ (87)		$ 342

	Nine Months Ended September 30,			
	2015		2014	
	Number of Unit Options	Weighted Average Exercise Price	Number of Unit Options	Weighted Average Exercise Price
Outstanding, beginning of year	1,458,300	$ 24.66	1,482,675	$ 24.66
Granted	—	—	—	—
Exercised [1]	—	—	—	—
Forfeited	(40,536)	24.68	(17,500)	24.46
Outstanding, end of period[2][3]	1,417,764	$ 24.66	1,465,175	$ 24.66
Options exercisable, end of period[4]	1,332,976	$ 24.67	732,025	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 805		$ 1,374

(1) No options were exercised during the three and nine months ended September 30, 2015 and 2014.
(2) The weighted average remaining contractual life for outstanding options at September 30, 2015 was 6.6 years.
(3) There were no aggregate intrinsic values of options outstanding at September 30, 2015 and 2014.
(4) The weighted average remaining contractual life for exercisable options at September 30, 2015 was 6.6 years. There were no intrinsic values for options exercisable at September 30, 2015 and 2014.

At September 30, 2015, the Partnership had approximately $0.1 million in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards, which is expected to be recognized over a weighted average period of 0.6 years. 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.

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. There were no restricted units granted, issued or outstanding in 2014 and 2015.

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,	
	2015	2014	2015	2014
Gas and oil production:				
Revenues	$221,799	$129,399	$501,949	$337,893
Operating costs and expenses	(41,591)	(51,391)	(130,224)	(133,038)
Depreciation, depletion and amortization expense	(37,079)	(61,811)	(116,559)	(168,600)
Asset impairment	(672,246)	—	(672,246)	—
Segment income (loss)	$(529,117)	$16,197	$(417,080)	$36,255
Well construction and completion:				
Revenues	$23,054	$61,204	$63,665	$126,917
Operating costs and expenses	(20,046)	(53,221)	(55,361)	(110,363)
Segment income	$3,008	$7,983	$8,304	$16,554
Other partnership management:(1)				
Revenues	$13,042	$16,096	$31,995	$42,143
Operating costs and expenses	(4,871)	(5,831)	(14,141)	(19,425)
Depreciation, depletion and amortization expense	(3,384)	(2,767)	(9,389)	(7,477)
Segment income	$4,787	$7,498	$8,465	$15,241
Reconciliation of segment income (loss) to net income (loss):				
Segment income (loss):				
Gas and oil production	$(529,117)	$16,197	$(417,080)	$36,255
Well construction and completion	3,008	7,983	8,304	16,554
Other partnership management	4,787	7,498	8,465	15,241
Total segment income (loss)	(521,322)	31,678	(400,311)	68,050
General and administrative expenses(2)	(13,978)	(13,124)	(44,400)	(50,894)
Interest expense(2)	(25,192)	(16,577)	(75,105)	(43,028)
Gain/(loss) on asset sales and disposal(2)	(362)	(92)	(276)	(1,686)
Net income (loss)	$(560,854)	$1,885	$(520,092)	$(27,558)
Reconciliation of segment revenues to total revenues:				
Segment revenues:				
Gas and oil production(3)	$221,799	$129,399	$501,949	$337,893
Well construction and completion	23,054	61,204	63,665	126,917
Other partnership management	13,042	16,096	31,995	42,143
Total revenues	$257,895	$206,699	$597,609	$506,953
Capital expenditures:				
Gas and oil production	$31,753	$50,596	$87,986	$134,390
Other partnership management	639	4,097	13,433	11,729
Corporate and other	407	1,237	871	4,460
Total capital expenditures	$32,799	$55,930	$102,290	$150,579

	September 30, 2015	December 31, 2014
Balance sheet:		
Goodwill:		
Gas and oil production	$—	$—
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	$13,639	$13,639
Total assets:		
Gas and oil production	$1,916,277	$2,601,171
Well construction and completion	30,188	39,558
Other partnership management	71,816	65,896
Corporate and other	78,477	84,928
	$2,096,758	$2,791,553

(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) Gain (loss) on asset sales and disposal, general and administrative expenses and interest expense have not been allocated to its reportable segments as it would be impracticable to reasonably do so for the periods presented.
(3) Gas and oil production segment revenues include gains on mark to market derivatives.

NOTE 16 — SUBSEQUENT EVENTS

Cash Distributions. On October 28, 2015, the Partnership declared a monthly distribution of $0.1083 per common unit for the month of September 30, 2015. The $11.9 million distribution, including $0.2 million and $0.6 million to the general partner and preferred limited partners, respectively, will be paid on November 13, 2015 to unitholders of record at the close of business on November 9, 2015.

On October 15, 2015, the Partnership paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from July 15, 2015 through October 14, 2015 to Class D Preferred Unitholders of record as of October 1, 2015.

On October 15, 2015, the Partnership paid a quarterly distribution of $0.671875 per Class E Preferred Unit, or $0.2 million, for the period from July 15, 2015 through October 14, 2015 to Class E Preferred Unitholders of record as of October 1, 2015.

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, 2014. 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 (NYSE: ARP) Delaware master-limited partnership (“MLP”) 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 (“Drilling Partnerships”), in which we coinvest, to finance a portion of our natural gas, crude oil and natural gas liquid production activities.

On February 27, 2015, our general partner, Atlas Energy Group, LLC (“Atlas Energy Group”; NYSE: ATLS) distributed 100% of its common units to existing unitholders of its then parent, Atlas Energy, L.P. (“Atlas Energy”), which was a publicly traded master-limited partnership (NYSE: ATLS) (Atlas Energy and Atlas Energy Group are collectively referred to as “ATLS”). Atlas Energy Group manages our operations and activities through its ownership of our general partner interest. Concurrent with Atlas Energy Group’s unit distribution, Atlas Energy and its midstream ownership interests merged into Targa Resources Corp. (“Targa”; NYSE: TRGP) and ceased trading. At September 30, 2015, Atlas Energy Group 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 23.6% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

In addition to its general and limited partner interest in us, ATLS also holds general and limited partner interests in the following:

- Atlas Growth Partners, L.P. (“AGP”), a Delaware limited partnership and an independent developer and producer of natural gas, oil and NGLs, with operations primarily focused in the Eagle Ford Shale; and
- Lightfoot Capital Partners, L.P. and Lightfoot Capital Partners GP, LLC, which incubate new MLPs and invest in existing MLPs.

FINANCIAL PRESENTATION

Our consolidated balance sheets at September 30, 2015 and December 31, 2014, and the consolidated statements of operations for the three and nine months ended September 30, 2015 and 2014 include our accounts and our wholly-owned subsidiaries. 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. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the consolidation of the financial statements.

SUBSEQUENT EVENTS

Cash Distributions. On October 28, 2015, we declared a monthly distribution of $0.1083 per common unit for the month of September 30, 2015. The $11.9 million distribution, including $0.2 million and $0.6 million to the general partner and preferred limited partners, respectively, will be paid on November 13, 2015 to unitholders of record at the close of business on November 9, 2015.

On October 15, 2015, we paid a quarterly distribution of $0.5390625 per Class D Preferred Unit, or $2.2 million, for the period from July 15, 2015 through October 14, 2015 to Class D Preferred Unitholders of record as of October 1, 2015.

On October 15, 2015, we paid a quarterly distribution of $0.6718750 per Class E Preferred Unit, or $0.2 million, for the period from July 15, 2015 through October 14, 2015 to Class E Preferred Unitholders of record as of October 1, 2015.

RECENT DEVELOPMENTS

Arkoma Acquisition. On June 5, 2015, we completed the acquisition of ATLS's coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma for approximately $31.5 million, net of purchase price adjustments (the "Arkoma Acquisition"). We funded the purchase price through the issuance of 6,500,000 common limited partner units. The Arkoma Acquisition had an effective date of January 1, 2015, however, as the acquisition constituted a transaction between entities under common control, we retrospectively adjusted our consolidated financial statements for dates prior to the date of acquisition to reflect our results on a consolidated basis with the results of the Arkoma assets as of or at the beginning of the respective period.

Issuance of Common Units. In May 2015, in connection with the Arkoma Acquisition, we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.5 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our revolving credit facility (see "Issuance of Units").

Issuance of Preferred Units. In April 2015, we issued 255,000 of our 10.75% Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units") at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. We pay distributions on the Class E Preferred Units at a rate of 10.75% per annum of the stated liquidation preference of $25.00 (see "Issuance of Units").

Credit Facility Amendment. On February 23, 2015, we entered into a Sixth Amendment to the Second Amended and Restated Credit Agreement (the "Sixth Amendment") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto, which amendment amends the Second Amended and Restated Credit Agreement (the "Credit Agreement"), dated July 31, 2013. Among other things, the Sixth Amendment:

- reduced the borrowing base under the Credit Agreement from $900.0 million to $750.0 million;
- permitted the incurrence of second lien debt in an aggregate principal amount up to $300.0 million;
- rescheduled the May 1, 2015 borrowing base redetermination for July 1, 2015;
- if the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, increased the applicable margin on Eurodollar loans and ABR loans by 0.25% from previous levels,
- following the next scheduled redetermination of the borrowing base, upon the issuance of senior notes or the incurrence of second lien debt, reduces the borrowing base by 25% of the stated amount of such senior notes or additional second lien debt; and
- revised the maximum ratio of Total Funded Debt to EBITDA to be (i) 5.25 to 1.0 as of the last day of the quarters ended on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ended on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ended on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter thereafter.

Second Lien Term Loan Facility. On February 23, 2015, we entered into a Second Lien Credit Agreement (the "Second Lien Credit Agreement") with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"). The Term Loan Facility matures on February 23, 2020.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries (the "Loan Parties") that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans (see “Credit Facilities”).

CONTRACTUAL REVENUE ARRANGEMENTS

Natural Gas. We market the majority of our natural gas production to gas marketers directly or to third party plant operators who process and market our gas. The sales price of natural gas produced is a function of the market in the area and typically linked to a regional index. The pricing indices for the majority of our production areas are as follows:

- Appalachian Basin - Dominion South Point, Tennessee Gas Pipeline Zone 4 (200 Leg), Transco Leidy Line, Columbia Appalachia, NYMEX and Transco Zone 5;
- Mississippi Lime - Southern Star;
- Barnett Shale and Marble Falls- primarily Waha;
- Raton - ANR, Panhandle, and NGPL;
- Black Warrior Basin - Southern Natural;
- Eagle Ford – Transco Zone 1;
- Arkoma – Enable Gas; and
- Other regions - primarily the Texas Gas Zone SL spot market (New Albany Shale) and the Cheyenne Hub spot market (Niobrara).

We attempt to sell the majority of our natural gas at monthly, fixed index prices and a smaller portion at index daily prices.

We hold firm transportation obligations on Colorado Interstate Gas for the benefit of production from the Raton Basin in the New Mexico/Colorado Area. The total of firm transportation obligations held is approximately 82,500 dth/d under contracts expiring in 2016. We also hold firm transportation obligations on East Tennessee Natural Gas (25,000 dth/d), Columbia Gas Transmission (14,500 dth/d) and Equitrans (12,300 dth/d) for the benefit of production from the central Appalachian Basin under contracts expiring between the years 2015 and 2024 ("dth" represents dekatherm, each, of which is equivalent to 1MMBtu.).

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/pipeline charges. The oil and natural gas liquids production of our Rangely assets flows into a common carrier pipeline and is sold at prevailing market prices, less applicable transportation and oil quality differentials. 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 to meet pipeline specifications for transport or sale to end users or marketers operating on the receiving pipeline. The resulting plant residue natural gas is sold as indicated above and our NGLs are generally priced and sold using the Mont Belvieu (TX) or Conway (KS) regional processing indices. 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 percentage 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.

Drilling Partnerships. Certain energy activities are conducted by us through, and a portion of our revenues are attributable to, sponsorship of our Drilling Partnerships. Drilling Partnership investor capital raised by us is deployed to drill and complete wells included within the partnership. As we deploy Drilling Partnership investor capital, we recognize certain management fees we are entitled to receive, including well construction and completion revenue and a portion of administration and oversight revenue. At each period end, if we have Drilling Partnership investor capital that has not yet been deployed, we will recognize a current liability titled "Liabilities Associated with Drilling Contracts" on our consolidated balance sheets. After the Drilling Partnership well is completed and turned in line (i.e.

wells that have been drilled, completed, and connected to a gathering system), we are entitled to receive additional operating and management fees, which are included within well services and administration and oversight revenue, respectively, on a monthly basis while the well is operating. In addition to the management fees we are entitled to receive for services provided, we are also entitled to our pro-rata share of Drilling Partnership gas and oil production revenue, which generally approximates 30%.

As the ultimate managing general partner of our Drilling Partnerships, we receive the following Drilling Partnership management fees:

- Well construction and completion. For each well that is drilled by a Drilling Partnership, we receive a 15% mark-up on those costs incurred to drill and complete the wells included within the partnership. Such fees are earned, in accordance with each Drilling Partnership's partnership agreement, and recognized as the services are performed, typically between 60 and 270 days.
- Administration and oversight. For each well drilled by a Drilling Partnership, we receive a fixed fee between $100,000 and $500,000, depending on the type of well drilled, which is earned in accordance with each Drilling Partnership's partnership agreement and recognized at the initiation of the well. Additionally, the Drilling Partnership pays us a monthly per well administrative fee of $75 for the life of the well. The well administrative fee is earned on a monthly basis as the services are performed; and
- Well services. Each Drilling Partnership pays us a monthly per well operating fee, currently $1,000 to $2,000, depending on the type of well, for the life of the well. Such fees are earned on a monthly basis as the services are performed.

Gathering and processing revenue includes gathering fees we charge to the Drilling Partnership wells for our processing plants in the New Albany and the Chattanooga Shales. Generally, we charge a gathering fee to the 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 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%.

While the historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized.

GENERAL TRENDS AND OUTLOOK

We expect our business to be affected by key trends in natural gas and oil production markets. 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 natural gas, oil and natural gas liquids commodity price markets have suffered significant declines during the fourth quarter of 2014 and the first three quarters of 2015. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. 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 and oil production from particular wells decrease. 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 plays throughout the United States. Through September 30, 2015, we have established production positions in the following operating areas:

- the Appalachia Basin assets, 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;
- 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 2013, as well as the Central Appalachia Basin in West Virginia and Virginia, where we established a position following our acquisition of assets from GeoMet Inc. in May 2014, and the Arkoma Basin in eastern Oklahoma, where we established a position following the Arkoma Acquisition (see "Recent Developments");
- the Barnett Shale and Marble Falls play, both in the Fort Worth Basin in northern Texas. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil.
- the Rangely field in northwest Colorado, a mature tertiary CO_2 flood with low-decline oil production, where we have a 25% non-operated net working interest position following our acquisition on June 30, 2014 ("Rangely Acquisition");
- the Eagle Ford Shale in south Texas, in which we and AGP acquired acreage and producing wells in November 2014;
- the Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area; and
- our 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; 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 and the number of wells we turned in line, both gross and for our interest, during the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Gross wells drilled:				
Appalachia - Utica	—	4	—	4
Barnett/Marble Falls	—	20	3	72
Eagle Ford	13	—	13	—
Mississippi Lime	—	6	4	22
Total	13	30	20	98
Net wells drilled(1):				
Appalachia - Utica	—	1	—	1
Barnett/Marble Falls	—	6	2	42
Eagle Ford	4	—	4	—
Mississippi Lime	—	2	3	9
Total	4	9	9	52
Gross wells turned in line(2):				
Appalachia - Utica	—	3	4	3
Barnett/Marble Falls	—	23	14	72
Eagle Ford	1	—	3	—
Mississippi Lime	2	4	13	15
Total	3	30	34	90
Net wells turned in line(2):				
Appalachia - Utica	—	1	1	1
Barnett/Marble Falls	—	9	4	46
Eagle Ford	1	—	2	—
Mississippi Lime	2	2	6	6
Total	3	12	13	53

(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.
(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.

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, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production:(1)(2)(3)				
Appalachia:				

Natural gas (MMcf)	3,123	3,516	8,879	10,670
Oil (000's Bbls)	30	34	94	106
NGLs (000's Bbls)	3	4	9	11
Total (MMcfe)	3,320	3,744	9,495	11,373
Coal-bed Methane:				
Natural gas (MMcf)	11,828	12,896	35,849	35,597
Oil (000's Bbls)	—	—	—	—
NGLs (000's Bbls)	—	—	—	—
Total (MMcfe)	11,828	12,896	35,849	35,597
Barnett/Marble Falls:				
Natural gas (MMcf)	4,019	5,311	12,795	15,955
Oil (000's Bbls)	46	117	171	304
NGLs (000's Bbls)	175	263	570	746
Total (MMcfe)	5,340	7,593	17,238	22,256
Rangely/Eagle Ford[(4)]:				
Natural gas (MMcf)	29	—	92	—

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Oil (000's Bbls)	329	236	1,035	236
NGLs (000's Bbls)	29	24	89	24
Total (MMcfe)	2,174	1,562	6,832	1,562
Mississippi Lime/Hunton:				
Natural gas (MMcf)	622	614	1,889	1,719
Oil (000's Bbls)	40	34	121	101
NGLs (000's Bbls)	52	50	156	143
Total (MMcfe)	1,175	1,117	3,553	3,181
Other operating areas:				
Natural gas (MMcf)	289	294	873	897
Oil (000's Bbls)	1	2	5	6
NGLs (000's Bbls)	29	31	68	92
Total (MMcfe)	470	492	1,310	1,489
Total production:				
Natural gas (MMcf)	19,910	22,632	60,376	64,838
Oil (000's Bbls)	446	423	1,425	754
NGLs (000's Bbls)	287	372	892	1,016
Total (MMcfe)	24,306	27,405	74,277	75,458
Production per day:(1)(2)(3)				
Appalachia:				
Natural gas (Mcfd)	33,950	38,218	32,522	39,083
Oil (Bpd)	326	367	343	390
NGLs (Bpd)	30	46	34	40
Total (Mcfed)	36,087	40,693	34,782	41,661
Coal-bed Methane:				
Natural gas (Mcfd)	128,560	140,177	131,314	130,393
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcfed)	128,560	140,177	131,314	130,393
Barnett/Marble Falls:				
Natural gas (Mcfd)	43,685	57,726	46,868	58,445
Oil (Bpd)	495	1,273	625	1,114
NGLs (Bpd)	1,898	2,861	2,088	2,732
Total (Mcfed)	58,043	82,535	63,144	81,523
Rangely/Eagle Ford(4):				
Natural gas (Mcfd)	313	—	337	—
Oil (Bpd)	3,573	2,567	3,790	865
NGLs (Bpd)	313	263	324	89
Total (Mcfed)	23,631	16,978	25,024	5,721
Mississippi Lime/Hunton:				
Natural gas (Mcfd)	6,763	6,679	6,921	6,295
Oil (Bpd)	433	366	443	368
NGLs (Bpd)	569	545	572	524
Total (Mcfed)	12,771	12,145	13,014	11,651

Other operating areas:				
Natural gas (Mcfd)	3,143	3,195	3,197	3,287
Oil (Bpd)	16	25	19	24
NGLs (Bpd)	311	334	248	337
Total (Mcfed)	5,104	5,349	4,799	5,453
Total production per day:				
Natural gas (Mcfd)	216,414	245,996	221,159	237,503

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Oil (Bpd)	4,842	4,598	5,220	2,761
NGLs (Bpd)	3,121	4,048	3,266	3,722
Total (Mcfed)	264,196	297,876	272,077	276,403

(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 (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, the Arkoma Basin in eastern Oklahoma, and the County Line area of Wyoming; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; Other operating areas include our production located in the Chattanooga, New Albany and Niobrara Shales.

(4) Production volumes and production volumes per day related to the Rangely field reflect only volumes during the three and nine months ended September 30, 2014. Production volumes and volumes per day for Eagle Ford were included effective November 5, 2014, the date of its acquisition.

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. 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, 2015 and 2014, along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production revenues (in thousands):(1)				
Appalachia:				
Natural gas revenue	$2,869	$7,529	$9,571	$30,925
Oil revenue	1,948	3,090	6,325	9,064
Natural gas liquids revenue	6	213	145	451
Total revenues	$4,823	$10,832	$16,041	$40,440
Coal-bed Methane:				
Natural gas revenue	$42,237	$51,371	$131,212	$146,751
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	$42,237	$51,371	$131,212	$146,751
Barnett/Marble Falls:				
Natural gas revenue	$10,400	$16,547	$32,587	$50,252
Oil revenue	602	10,838	5,043	27,826
Natural gas liquids revenue	2,339	7,394	8,058	20,392
Total revenues	$13,341	$34,779	$45,688	$98,470
Rangely/Eagle Ford(6):				
Natural gas revenue	$73	$—	$340	$—
Oil revenue	24,777	20,478	80,627	20,478
Natural gas liquids revenue	933	1,701	3,234	1,701
Total revenues	$25,783	$22,179	$84,201	$22,179
Mississippi Lime/Hunton:				
Natural gas revenue	$1,253	$2,569	$3,819	$7,395
Oil revenue	1,381	3,514	4,651	9,686
Natural gas liquids revenue	646	1,855	2,367	5,621
Total revenues	$3,280	$7,938	$10,837	$22,702
Other operating areas:				
Natural gas revenue	$1,087	$1,235	$3,479	$3,910
Oil revenue	146	231	454	572
Natural gas liquids revenue	37	834	331	2,869
Total revenues	$1,270	$2,300	$4,264	$7,351
Total production revenues:				
Natural gas revenue	$57,919	$79,251	$181,008	$239,233
Oil revenue	28,854	38,151	97,100	67,626
Natural gas liquids revenue	3,961	11,997	14,135	31,034
Total revenues	$90,734	$129,399	$292,243	$337,893
Average sales price:				
Natural gas (per Mcf):(2)				
Total realized price, after hedge(3) (4)	$3.30	$3.56	$3.41	$3.79
Total realized price, before hedge(3)	$2.28	$3.48	$2.32	$4.07
Oil (per Bbl):(2)				
Total realized price, after hedge(4)	$88.42	$90.18	$83.99	$89.71
Total realized price, before hedge	$43.25	$91.08	$46.74	$93.45
Natural gas liquids (per Bbl):(2)				
Total realized price, after hedge(4)	$21.42	$32.21	$22.17	$30.54
Total realized price, before hedge	$11.01	$32.18	$13.00	$32.16

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Production costs (per Mcfe):(1) (2)				
Appalachia:				
Lease operating expenses(5)	$ 0.95	$ 1.17	$1.05	$ 1.10
Production taxes	0.06	0.08	0.06	0.06
Transportation and compression	0.24	0.31	0.29	0.47
	$ 1.25	$ 1.57	$1.40	$ 1.64
Coal-bed Methane:				
Lease operating expenses	$ 1.06	$ 1.13	$1.05	$ 1.07
Production taxes	0.20	0.32	0.21	0.33
Transportation and compression	0.32	0.33	0.33	0.33
	$ 1.58	$ 1.78	$1.60	$ 1.73
Barnett/Marble Falls:				
Lease operating expenses	$ 1.30	$ 1.36	$1.33	$ 1.44
Production taxes	0.17	0.28	0.17	0.27
Transportation and compression	0.15	0.06	0.10	0.06
	$ 1.62	$ 1.70	$1.59	$ 1.78
Rangely/Eagle Ford(6):				
Lease operating expenses	$ 3.35	$ 3.79	$3.36	$ 3.79
Production taxes	0.49	0.77	0.45	0.77
Transportation and compression	0.02	—	0.03	—
	$ 3.86	$ 4.56	$3.84	$ 4.56
Mississippi Lime/Hunton:				
Lease operating expenses	$ 1.21	$ 1.55	$1.40	$ 1.52
Production taxes	0.05	0.14	0.06	0.16
Transportation and compression	0.27	0.26	0.27	0.29
	$ 1.53	$ 1.95	$1.73	$ 1.96
Other operating areas:				
Lease operating expenses	$ 0.77	$ 0.85	$0.84	$ 0.82
Production taxes	0.09	0.28	0.12	0.22
Transportation and compression	0.18	0.22	0.20	0.21
	$ 1.04	$ 1.35	$1.16	$ 1.25
Total production costs:				
Lease operating expenses(5)	$ 1.30	$ 1.37	$1.34	$ 1.26
Production taxes	0.19	0.30	0.20	0.27
Transportation and compression	0.24	0.23	0.24	0.26
	$ 1.74	$ 1.89	$1.78	$ 1.79

(1) Appalachia includes our production located in Pennsylvania, Ohio, New York and West Virginia (excluding the Cedar Bluff area); Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, the Arkoma Basin in eastern Oklahoma, and the County Line area of Wyoming; Rangely/Eagle Ford includes our 25% non-operated net working interest in oil and natural gas liquids producing assets in the Rangely field in northwest Colorado and our production located in southern Texas; Other operating areas include our production located in the Chattanooga,

New Albany 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, 2015 and 2014. Including the effect of this subordination, the average realized gas sales price was $3.25 per Mcf ($2.23 per Mcf before the effects of financial hedging) and $3.50 per Mcf ($3.43 per Mcf before the effects of financial hedging) for the three months ended September 30, 2015 and 2014, respectively, and $3.35 per Mcf ($2.27 per Mcf before the effects of financial hedging) and $3.69 per Mcf ($3.97 per Mcf before the effects of financial hedging) for nine months ended September 30, 2015 and 2014, respectively.

(4) Includes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015, consisting of $6.8 million associated with natural gas derivative contracts, $10.5 million associated with crude oil derivative contracts, and $2.2 million associated with natural gas liquids derivative contracts for the three months ended September 30, 2015, and $21.4 million associated with natural gas derivative contracts, $22.6 million associated with crude oil derivative contracts, and $5.6 million associated with natural gas liquids derivative contracts for the nine months ended September 30, 2015 (see "Item 1. Financial Statements – Note 8").

(5) 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, 2015 and 2014. Including the effects of these costs, Appalachia lease operating expenses were $0.77 per Mcfe ($1.07 per Mcfe for total production costs) and $1.07 per Mcfe ($1.47 per Mcfe for total production costs) for the three months ended September 30, 2015 and 2014, respectively, and $0.88 per Mcfe ($1.22 per Mcfe for total production costs) and $0.93 per Mcfe ($1.46 per Mcfe for total production costs) for the nine months ended September 30, 2015 and 2014, respectively. Including the effects of these costs, total lease operating expenses were $1.28 per Mcfe ($1.71 per Mcfe for total production costs) and $1.35 per Mcfe ($1.88 per Mcfe for total production costs) for the three months ended September 30, 2015 and 2014, respectively, and $1.32 per Mcfe ($1.75 per Mcfe for total production costs) and $1.23 per Mcfe ($1.76 per Mcfe for total production costs) for the nine months ended September 30, 2015 and 2014, respectively.

(6) Production revenue and production costs related to the Rangely field reflect only activity during the three and nine months ended September 30, 2014. Production revenue and production costs for Eagle Ford were included effective November 5, 2014, the date of its acquisition.

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. Total production revenues were $90.7 million for the three months ended September 30, 2015, a decrease of $38.7 million from $129.4 million for the three months ended September 30, 2014. This decrease principally consisted of a $21.5 million decrease attributable to the Barnett Shale/Marble Falls operations, a $9.1 million decrease attributable to the coal-bed methane assets, a $6.0 million decrease attributable to the Appalachia assets, a $4.7 million decrease attributable to the Mississippi Lime/Hunton assets, and a $1.0 million decrease associated with our other operating areas, partially offset by a $3.6 million increase attributable to the newly acquired Rangely and Eagle Ford assets.

Total production costs were $41.6 million for the three months ended September 30, 2015, a decrease of $9.8 million from $51.4 million for the three months ended September 30, 2014. This decrease primarily consisted of a $4.3 million decrease attributable to the Barnett Shale/Marble Falls assets, a $4.3 million decrease attributable to the coal-bed methane assets, a $1.7 million decrease attributable to the Appalachia operations, a $0.4 million decrease attributable to the Mississippi Lime/Hunton assets, a $0.2 million decrease associated with our other operating areas, and a $0.2 million increase in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships, partially offset by a $1.3 million increase attributable to the newly acquired Rangely/Eagle Ford assets. Total production costs per Mcfe decreased to $1.74 per Mcfe for the three months ended September 30, 2015 from $1.89 per Mcfe for the comparable prior year period primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Total production revenues were $292.2 million for the nine months ended September 30, 2015, a decrease of $45.7 million from $337.9 million for the nine months ended September 30, 2014. This decrease principally consisted of a $52.8 million decrease attributable to the Barnett Shale/Marble Falls operations, a $24.4 million decrease attributable to the Appalachia assets, an $11.9 million decrease attributable to the Mississippi Lime/Hunton assets, a $15.5 million decrease attributable to the coal-bed methane assets, and a $3.1 million decrease associated with our other operating areas, partially offset by a $62.0 million increase attributable to the newly acquired Rangely and Eagle Ford assets.

Total production costs were $130.2 million for the nine months ended September 30, 2015, a decrease of $2.8 million from $133.0 million for the nine months ended September 30, 2014. This decrease primarily consisted of a $12.1 million decrease attributable to the Barnett Shale/Marble Falls assets, a $5.3 million decrease attributable to the Appalachia operations, a $4.5 million decrease attributable to the coal-bed methane assets, a $0.4 million decrease associated with our other operating areas, and a $0.1 million decrease attributable to the Mississippi Lime/Hunton assets, partially offset by a $19.2 million increase attributable to the newly acquired Rangely/Eagle Ford assets, and a $0.4 million decrease in the credit received against lease operating expenses pertaining to the subordination of our revenue within our Drilling Partnerships. Total production costs per Mcfe decreased to $1.78 per Mcfe for the nine months ended September 30, 2015 from $1.79 per Mcfe for the comparable prior year period primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

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. 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 presents the amounts of Drilling Partnership investor capital raised and deployed (in thousands), as well as 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,	
	2015	2014	2015	2014
Drilling partnership investor capital:				
Raised	$24,954	$18,055	$24,954	$19,610
Deployed	$23,054	$61,204	$63,665	$126,917
Average construction and completion:				
Revenue per well	$7,204	$2,121	$3,942	$2,476
Cost per well	6,264	1,845	3,428	2,153
Gross profit per well	$940	$276	$514	$323
Gross profit margin	$3,008	$7,983	$8,304	$16,554
Partnership net wells associated with revenue recognized[(1)]:				
Appalachia - Utica	—	2	2	3
Barnett/Marble Falls	—	22	5	37
Rangely/Eagle Ford	3	—	4	—
Mississippi Lime/Hunton	—	5	5	11
Total	3	29	16	51

(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, 2015 Compared with the Three Months Ended September 30, 2014. Well construction and completion segment margin was $3.0 million for the three months ended September 30, 2015, a decrease of $5.0 million from $8.0 million for the three months ended September 30, 2014. This decrease consisted of a $7.1 million decrease related to fewer wells recognized for revenue within our Drilling Partnerships, partially offset by a $2.1 million increase associated with our higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Eagle Ford Shale wells within our Drilling Partnerships during the three months ended September 30, 2015 compared with the prior year period. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in its average cost per well also results in a proportionate increase or decrease in its average revenue per well, which directly affects the number of wells we drill.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Well construction and completion segment margin was $8.3 million for the nine months ended September 30, 2015, a decrease of $8.3 million from $16.6 million for the nine months ended September 30, 2014. This decrease consisted of an $11.4 million decrease related to fewer wells recognized for revenue within our Drilling Partnerships, partially offset by a $3.1 million increase associated with our higher gross profit margin per well. Average revenue and cost per well increased between periods due primarily to higher capital deployed for Eagle Ford Shale wells within our Drilling Partnerships during the nine months ended September 30, 2015 compared with 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 play, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales. The following table presents the number of gross and net development wells we drilled for our Drilling Partnerships during the three and nine months ended September 30, 2015 and 2014. There were no exploratory wells drilled during the three and nine months ended September 30, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Gross partnership wells drilled:				
Appalachia - Utica	—	4	—	4
Barnett/Marble Falls	—	20	2	52
Eagle Ford	10	—	10	—
Mississippi Lime/Hunton	—	6	2	17
Total	10	30	14	73
Net partnership wells drilled:				
Appalachia - Utica	—	4	—	4
Barnett/Marble Falls	—	20	2	40
Eagle Ford	10	—	10	—
Mississippi Lime/Hunton	—	6	1	17
Total	10	30	13	61

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. Administration and oversight fee revenues were $5.5 million for the three months ended September 30, 2015, a decrease of $0.7 million from $6.2 million for the three months ended September 30, 2014. This decrease was due to a decrease in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls and the Mississippi Lime plays.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Administration and oversight fee revenues were $7.3 million for the nine months ended September 30, 2015, a decrease of $4.8 million from $12.1 million for the nine months ended September 30, 2014. This decrease was due to a decrease in the number of wells spud within the current year period compared with the prior year period, particularly within the Marble Falls and the Mississippi Lime plays.

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, 2015 Compared with the Three Months Ended September 30, 2014. Well services revenues were $5.8 million for the three months ended September 30, 2015, a decrease of $0.8 million from $6.6 million for the three months ended September 30, 2014. Well services expenses were $2.4 million for the three months ended September 30, 2015, a decrease of $0.2 million from $2.6 million for the three months ended September 30, 2014. The decrease in well services revenue is primarily related to our continued efforts to increase production through intermittent operation of certain legacy wells. The decrease in well services expense is primarily related to lower labor and other employee costs.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Well services revenues were $18.6 million for the nine months ended September 30, 2015, an increase of $0.2 million from $18.4 million for the nine months ended September 30, 2014. Well services expenses were $6.7 million for the nine months ended September 30, 2015, a decrease of $0.8 million from $7.5 million for the nine months ended September 30, 2014. The increase in well services revenue is primarily related to the increased utilization of our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls plays by our Drilling Partnership wells, partially offset by a decrease in revenue pertaining to our continued efforts to increase production through intermittent operation of certain legacy wells. The decrease in well services expense is primarily related to lower labor and other employee 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, 2015 Compared with the Three Months Ended September 30, 2014. Our net gathering and processing expense for the three months ended September 30, 2015 was net expense of $0.8 million, an unfavorable movement of $0.6 million compared with net expense of $0.2 million for the three months ended September 30, 2014. This unfavorable movement 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, and lower gathering fees from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline, as compared to the prior year period.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Our net gathering and processing expense for the nine months ended September 30, 2015 was net expense of $1.4 million, an unfavorable movement of $0.8 million compared with net expense of $0.6 million for the nine months ended September 30, 2014. This unfavorable movement was principally due to lower gathering fees from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline, in comparison with the prior year period.

Gain on Mark-to-Market Derivatives

On January 1, 2015, we discontinued hedge accounting for our qualified commodity derivatives. As such, subsequent changes in fair value of these derivatives are recognized immediately within gain (loss) on mark-to-market derivatives on our consolidated statements of operations. The fair values of these commodity derivative instruments at December 31, 2014, which were recognized in accumulated other comprehensive income within partners’ capital on our balance sheet, will be reclassified to our consolidated statements of operations in the future at the time the originally hedged physical transactions settle.

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. We recognized a gain on mark-to-market derivatives of $131.1 million for the three months ended September 30, 2015. This gain was due primarily to mark-to-market gains in the current quarter primarily related to the change in natural gas and oil prices during the period. There were no gains or losses on mark-to-market derivatives during the three months ended September 30, 2014.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. We recognized a gain on mark-to-market derivatives of $209.7 million for the nine months ended September 30, 2015. This gain was due primarily to mark-to-market gains in the current year primarily related to the change in natural gas and oil prices during the year. There were no gains or losses on mark-to-market derivatives during the nine months ended September 30, 2014.

Other, net

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. Other, net for the three months ended September 30, 2015 was income of approximately $20,000 compared with income of $0.3 million for the three months ended September 30, 2014.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Other, net for the nine months ended September 30, 2015 was income of approximately $0.1 million, compared to income of $0.3 million for the nine months ended September 30, 2014.

OTHER COSTS AND EXPENSES

General and Administrative Expenses

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. Total general and administrative expenses increased to $14.0 million for the three months ended September 30, 2015 compared with $13.1 million for the three months ended September 30, 2014. This increase was primarily due to a $1.8 million increase related to the timing of the initiation of our 2015 Drilling Partnership program and a $1.2 million increase in other corporate activities during the current year, partially offset by a $1.7 million decrease in non-cash compensation expense, and a $0.4 million decrease in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Total general and administrative expenses decreased to $44.4 million for the nine months ended September 30, 2015 compared with $50.9 million for the nine months ended September 30, 2014. This decrease was primarily due to a decrease in non-recurring transaction costs related to the acquisitions of assets in the current and prior year periods.

Depreciation, Depletion and Amortization

Total depreciation, depletion and amortization decreased to $40.5 million for the three months ended September 30, 2015 compared with $64.6 million for the comparable prior year period, which was primarily due to a $24.7 million decrease in our depletion expense.

Total depreciation, depletion and amortization decreased to $125.9 million for the nine months ended September 30, 2015 compared with $176.1 million for the comparable prior year period, which was primarily due to a $52.0 million decrease in our depletion expense.

The following table presents a summary of our depreciation, depletion and amortization expense and our depletion expense per Mcfe for our operations for the respective periods (in thousands, except for percentage and per Mcfe data):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Depreciation, depletion and amortization:				
Depletion expense	$37,079	$61,811	$116,559	$168,600
Depreciation and amortization expense	3,384	2,767	9,389	7,477
	$40,463	$64,578	$125,948	$176,077
Depletion expense:				
Total	$37,079	$61,811	$116,559	$168,600

Depletion expense as a percentage of gas and oil production revenue	41 %	48 %	40 %	50 %
Depletion per Mcfe	$1.53	$2.26	$1.57	$2.23

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, 2015, depletion expense was $37.1 million, a decrease of $24.7 million compared with $61.8 million for the three months ended September 30, 2014. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 41% for the three months ended September 30, 2015, compared with 48% for the three months ended September 30, 2014. Depletion expense per Mcfe decreased to $1.53 for the three months ended September 30, 2015, compared to $2.26 for the prior year comparable period. The decreases in depletion expense, depletion expense as a percentage of gas and oil revenues, and depletion expense per Mcfe when compared with the comparable prior year period are the result of the asset impairments recognized at December 31, 2014.

For the nine months ended September 30, 2015, depletion expense was $116.6 million, a decrease of $52.0 million compared with $168.6 million for the nine months ended September 30, 2014. Our depletion expense of gas and oil properties as a percentage of gas and oil revenues decreased to 40% for the nine months ended September 30, 2015, compared with 50% for the nine months ended September 30, 2014. Depletion expense per Mcfe decreased to $1.57 for the nine months ended September 30, 2015, compared to $2.23 for the prior year comparable period. The decreases in depletion expense, depletion expense as a percentage of gas and oil revenues, and depletion expense per Mcfe when compared with the comparable prior year period are the result of the asset impairments recognized at December 31, 2014.

Asset Impairment

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. Asset impairment for the three months ended September 30, 2015 was $740.2 million as compared with no impairment for the comparable prior year period. The $740.2 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, reduced by $68.0 million of future hedge gains reclassified from accumulated other comprehensive income.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Asset impairment for the nine months ended September 30, 2015 was $740.2 million as compared with no impairment for the comparable prior year period. The $740.2 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, reduced by $68.0 million of future hedge gains reclassified from accumulated other comprehensive income.

Interest Expense

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. Interest expense for the three months ended September 30, 2015 was $25.2 million as compared with $16.6 million for the comparable prior year period. The $8.6 million increase in our interest expense consisted of a $6.8 million increase associated with our Term Loan Facility, a $1.7 million increase associated with interest expense on our Senior Notes, and a $0.8 million increase associated with amortization of our deferred financing costs, partially offset by a $0.7 million decrease associated with lower weighted-average outstanding borrowings under our revolving credit facility. The increase associated with our Senior Notes is primarily due to the issuance of an additional $75.0 million of our 9.25% Senior Notes due 2021 in October 2014. The increase in interest expense for our Term Loan Facility related to our entry into the Term Loan Facility in February 2015.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. Interest expense for the nine months ended September 30, 2015 was $75.1 million as compared with $43.0 million for the comparable prior year period. The $32.1 million increase in our interest expense consisted of a $16.3 million increase associated with our Term Loan Facility, an $8.5 million increase associated with interest expense on our Senior Notes, a $4.3 million accelerated amortization charge related to our reduced credit facility borrowing base, a $2.6 million increase associated with amortization of our deferred financing costs, and a $0.3 million increase associated with higher weighted-average outstanding borrowings under our revolving credit facility. The increase associated with our Senior Notes is primarily due to the issuance of an additional $100.0 million of our 7.75% Senior Notes due 2021 in June 2014 and an additional $75.0 million of our 9.25% Senior Notes due 2021 in October 2014. The increase in interest expense for our Term Loan Facility related to our entry into the Term Loan Facility in February 2015.

Loss on Asset Sales and Disposal

Three Months Ended September 30, 2015 Compared with the Three Months Ended September 30, 2014. During the three months ended September 30, 2015 and 2014, we recognized losses on asset sales and disposal of $0.4 million and $0.1 million, respectively. The $0.4 million loss on asset sales and disposal for the three months ended September 30, 2015 was primarily related to $0.4 million of plugging and abandonment costs for certain wells in the New Albany Shale, partially offset by a $0.1 million insurance reimbursement for the Mossy Oak plant fire in Indiana in 2014.

Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014. During the nine months ended September 30, 2015 and 2014, we recognized losses on asset sales and disposal of $0.3 million and $1.7 million, respectively. The $0.3 million loss on asset sales and disposal for the nine months ended September 30, 2015 was primarily related to $0.4 million of plugging and abandonment costs for certain wells in the New Albany Shale, partially offset by a $0.1 million insurance reimbursement for the Mossy Oak plant fire in Indiana in 2014. The $1.7 million loss on asset sales and disposal for the nine months ended September 30, 2014 was primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement.

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 revolving credit facility (see “Credit Facilities”). Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and 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 limited partner units or asset sales.

We rely on cash flow from operations and our credit facilities 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 facilities and other borrowings, the issuance of additional limited partner units, the sale of assets and other transactions.

Cash Flows – Nine Months Ended September 30, 2015 Compared with the Nine Months Ended September 30, 2014

Net cash provided by operating activities of $101.3 million for the nine months ended September 30, 2015 represented a favorable movement of $14.2 million from net cash provided by operating activities of $87.1 million for the comparable prior year period. The $14.2 million favorable movement in net cash provided by operating activities resulted from a $73.7 million favorable movement in working capital, partially offset by a $59.5 million unfavorable movement in net loss, excluding non-cash items. The $59.5 unfavorable movement in net loss, excluding non-cash items, was principally due to a $492.5 million unfavorable movement in net loss, a $192.5 million unfavorable movement in unrealized gain on derivatives subsequent to our discontinuation of hedge accounting on January 1, 2015, a $50.1 million unfavorable movement in depreciation, depletion and amortization, a $1.9 million unfavorable movement in gain/loss on asset sales and disposal and a $1.8 million unfavorable movement in non-cash compensation, partially offset by a $672.2 million asset impairment charge and a $7.1 million favorable movement in amortization of deferred financing costs. The $73.7 million favorable movement in working capital was due to a $239.1 million favorable movement in accounts receivable, prepaid expenses and other, partially offset by a $165.4 million unfavorable movement in accounts payable and accrued liabilities.

Net cash used in investing activities of $138.9 million for the nine months ended September 30, 2015 represented a favorable movement of $521.8 million from net cash used in investing activities of $660.7 million for the comparable prior year period. This favorable movement was principally due to a $473.1 million decrease in net cash paid for acquisitions and a decrease in capital expenditures of $48.3 million. See further discussion of capital expenditures under “Capital Requirements.”

Net cash provided by financing activities of $24.7 million for the nine months ended September 30, 2015 represented an unfavorable movement of $552.3 million from net cash provided by financing activities of $577.0 million for the comparable prior year period. This unfavorable movement was principally due to a decrease of $473.7 million for borrowings under our term loans and revolving credit facility, a $336.8 million decrease in net proceeds from issuance of our common limited partner units, a $97.4 million decrease in net proceeds from our senior notes and a $37.1 million unfavorable movement in deferred financing costs, distribution equivalent rights and other, partially offset by a decrease of $343.2 million in repayments under our revolving credit facility, a $42.6 million decrease in cash distributions paid to limited partners and a $6.9 million increase in net proceeds from the issuance of our preferred limited partner units. The gross amount of borrowings and repayments under the revolving credit facilities 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 the revolving credit facilities, and payments, which generally occur throughout the period and increase borrowings under our revolving credit facilities, which is generally common practice for our business and industries.

The issuance of $20.0 million in Class D Preferred Units as partial payment for the Eagle Ford Acquisition represented a non-cash transaction during the nine months ended September 30, 2015.

Capital Requirements

The capital requirements of our natural gas and oil production consist primarily of:

- Maintenance capital expenditures — oil and gas assets naturally decline in future periods and, as such, we recognize the estimated capitalized cost of stemming such decline in production margin for the purpose of stabilizing our distributable cash flow and cash distributions, which we refer to as maintenance capital expenditures. We calculate the estimate of maintenance capital expenditures by first multiplying forecasted future full year production margin by 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 hypothetical wells we expect to drill in future periods, including Marcellus Shale, Utica Shale, Mississippi Lime and Marble Falls wells, on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including historical costs of similar wells and characteristics of each individual well. First year margin from wells included within maintenance capital 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 — we consider expansion capital expenditures to be any capital expenditure costs expended that are not maintenance capital expenditures – generally, this will include expenditures to increase, rather than maintain, production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

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,	
	2015	2014	2015	2014
Maintenance capital expenditures	$ 13,456	$ 22,400	$ 42,788	$ 46,300
Expansion capital expenditures	19,343	33,530	59,502	104,279
Total	$ 32,799	$ 55,930	$ 102,290	$ 150,579

During the three months ended September 30, 2015, our $32.8 million of total capital expenditures consisted primarily of $14.4 million for wells drilled exclusively for our own account compared with $23.1 million for the comparable prior year period, $7.3 million of investments in our Drilling Partnerships compared with $16.8 million for the prior year comparable period, $6.1 million of leasehold acquisition costs compared with $7.0 million for the prior year comparable period and $5.0 million of corporate and other costs compared with $9.0 million for the prior year comparable period, which primarily related to decreases in corporate salt water disposal well costs and gathering and processing costs.

During the nine months ended September 30, 2015, our $102.3 million of total capital expenditures consisted primarily of $40.1 million for wells drilled exclusively for our own account compared with $64.9 million for the comparable prior year period, $26.0 million of investments in our Drilling Partnerships compared with $41.8 million for the prior year comparable period, $9.9 million of leasehold acquisition costs compared with $18.3 million for the prior year comparable period and $26.3 million of corporate and other costs compared with $25.6 million for the prior year comparable period.

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, 2015, we are committed to expend approximately $45.0 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, 2015, our off-balance sheet arrangements were limited to our letters of credit outstanding of $4.3 million and commitments to spend $45.0 million related to our drilling and completion and capital expenditures, excluding acquisitions.

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of September 30, 2015, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

In connection with the Eagle Ford Acquisition, we guaranteed the timely payment of the deferred portion of the purchase price that is to be paid by AGP. Pursuant to the agreement between us and AGP, we will have the right to receive some or all of the assets acquired by AGP in the event of its failure to contribute its portion of any deferred payments. In connection with the second installment payments, we and AGP amended the purchase and sale agreement to alter the timing and amount of the quarterly installment payments beginning on March 31, 2015 and ending December 31, 2015. In September 2015, ARP agreed with AGP to have AGP transfer its remaining $36.3 million of deferred purchase obligation, along with the related undeveloped natural gas and oil properties, to ARP.

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.

On January 29, 2014, the general partner's board of directors approved a modification to our cash distribution payment practice to a monthly cash distribution program. Monthly cash distributions are paid approximately 45 days following the end of each respective monthly period.

Available cash, as defined in our Partnership Agreement, will generally be distributed as follows:

- first, 98% to our Class D and E preferred unitholders and 2% to our general partner until the distribution to each of our Class D and Class E Preferred Units is an amount equal to its fixed quarterly distribution;
- 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 per quarter 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 FACILITIES

Revolving Credit Facility

We are a party to our Second Amended and Restated Credit Agreement dated July 31, 2013, as amended, with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto (the “Credit Agreement”), which provides for a senior secured revolving credit facility with a borrowing base of $750.0 million as of September 30, 2015.

Our borrowing base is scheduled for semi-annual redeterminations in November 2015 and thereafter in May and November of each year. In July 2015, the redetermination by the lenders reaffirmed our $750.0 million borrowing base. The Credit Agreement also provides that our borrowing base will be reduced by 25% of the stated amount of any senior notes issued, or additional second lien debt incurred, after July 1, 2015. At September 30, 2015, $563.0 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 $4.3 million was outstanding at September 30, 2015. 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 non-guarantor subsidiaries of ours are minor. Borrowings under the credit facility bear interest, at our election, at either an adjusted LIBOR rate plus an applicable margin between 1.50% 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 0.50% and 1.75% per annum. If the borrowing base utilization (as defined in the Credit Agreement) is less than 90%, the applicable margin on Eurodollar loans and ABR loans will be increased by 0.25%. We are also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% per annum if less than 50% of the borrowing base is utilized and 0.5% if 50% or more of the borrowing base is utilized, which is included within interest expense on our combined consolidated statements of operations.

The Credit Agreement contains customary covenants that limit our ability to incur additional indebtedness (excluding second lien debt in an aggregate principal amount of up to $300.0 million), 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, 2015. The Credit Agreement also requires us to maintain a ratio of Total Funded Debt (as defined in the Credit Agreement) to EBITDA (as defined in the Credit Agreement) (actual or annualized, as applicable), calculated over a period of four consecutive fiscal quarters, of not greater than (i) 5.25 to 1.0 as of the last day of the quarters ending on March 31, 2015, June 30, 2015, September 30, 2015, December 31, 2015 and March 31, 2016, (ii) 5.00 to 1.0 as of the last day of the quarters ending on June 30, 2016, September 30, 2016 and December 31, 2016, (iii) 4.50 to 1.0 as of the last day of the quarter ending on March 31, 2017 and (iv) 4.00 to 1.0 as of the last day of each quarter 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.

Term Loan Facility

On February 23, 2015, we entered into a Second Lien Credit Agreement with certain lenders and Wilmington Trust, National Association, as administrative agent. The Second Lien Credit Agreement provides for a second lien term loan in an original principal amount of $250.0 million (the "Term Loan Facility"), and is presented net of $6.6 million of unamortized discount at September 30, 2015. The Term Loan Facility matures on February 23, 2020.

We have the option to prepay the Term Loan Facility at any time, and we are required to offer to prepay the Term Loan Facility with 100% of the net cash proceeds from the issuance or incurrence of any debt and 100% of the excess net cash proceeds from certain asset sales and condemnation recoveries. We are also required to offer to prepay the Term Loan Facility upon the occurrence of a change of control. All prepayments are subject to the following premiums, plus accrued and unpaid interest:

- the make-whole premium (plus an additional amount if such prepayment is optional and funded with proceeds from the issuance of equity) for prepayments made during the first 12 months after the closing date;
- 4.5% of the principal amount prepaid for prepayments made between 12 months and 24 months after the closing date;
- 2.25% of the principal amount prepaid for prepayments made between 24 months and 36 months after the closing date; and
- no premium for prepayments made following 36 months after the closing date.

Our obligations under the Term Loan Facility are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries (the "Loan Parties") that guarantee our existing first lien revolving credit facility. In addition, the obligations under the Term Loan Facility are guaranteed by our material restricted subsidiaries. Borrowings under the Term Loan Facility bear interest, at our option, at either (i) LIBOR plus 9.0% or (ii) the highest of (a) the prime rate, (b) the federal funds rate plus 0.50%, (c) one-month LIBOR plus 1.0% and (d) 2.0%, each plus 8.0% (an "ABR Loan"). Interest is generally payable at the applicable maturity date for Eurodollar loans and quarterly for ABR loans.

The Second Lien Credit Agreement contains customary covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred stock, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Credit Agreement contains covenants substantially similar to those in our existing first lien revolving credit facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. We were in compliance with these covenants as of September 30, 2015.

Under the Second Lien Credit Agreement, we may elect to add one or more incremental term loan tranches to the Term Loan Facility so long as the aggregate outstanding principal amount of the Term Loan Facility plus the principal amount of any incremental term loan does not exceed $300.0 million and certain other conditions are adhered to. Any such incremental term loans may not mature on a date earlier than February 23, 2020.

SENIOR NOTES

At September 30, 2015, we had $374.6 million outstanding of our 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"). The 7.75% Senior Notes were presented net of a $0.4 million unamortized discount as of September 30, 2015. 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 for 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, we may redeem the 7.75% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid 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. 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 7.75% Senior Notes.

At September 30, 2015, we had $324.0 million outstanding of our 9.25% senior unsecured notes due 2021 (“9.25% Senior Notes”). The 9.25% Senior Notes were presented net of a $1.0 million unamortized discount as of September 30, 2015. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time prior to August 15, 2017, we may redeem the 9.25% Senior Notes, in whole or in part, at a redemption price equal to 100% of the principal amount of the notes plus the Applicable Premium (as defined in the governing indenture), plus accrued and unpaid interest, if any. 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 its 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 its 9.25% Senior Notes at the redemption price of 100.0%. 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 its 9.25% Senior Notes.

In connection with the issuance of the $75.0 million of 9.25% Senior Notes on October 14, 2014, 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 by July 11, 2015. On April 15, 2015, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was subsequently launched on April 15, 2014 and expired on May 13, 2015.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% 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 7.75% Senior Notes and 9.25% Senior Notes contain covenants, including limitations on 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. We were in compliance with these covenants as of September 30, 2015.

SECURED HEDGE FACILITY

At September 30, 2015, 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 the ultimate 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 the ultimate 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

In August 2015, we entered into a distribution agreement with MLV & Co. LLC (“MLV”). Pursuant to the distribution agreement, we may sell from time to time through MLV our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units (“Class D Preferred Units”) and Class E Cumulative Redeemable Perpetual Preferred Units (“Class E Preferred Units”) having a maximum aggregate offering price of up $100 million. Sales of Class D and Class E Preferred 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 NYSE, the existing trading market for the Units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We will pay MLV a commission, which shall not be more than 3.0% of the gross sales price of Class D and Class E Preferred Units. We have agreed to reimburse MLV for certain expenses incurred in connection with entering into the distribution agreement. Under the terms of the distribution agreement, we may also sell Class D and Class E Preferred Units from time to time to MLV as principal for its own account at a price to be agreed upon at the time of sale. Any sale of Class D and Class E Preferred Units to MLV as principal would be pursuant to the terms of a separate terms agreement between us and MLV. During the three and nine months ended September 30, 2015, the Partnership issued 90,328 Class D Preferred Units and 1,083 Class E Preferred Units under the preferred equity distribution program for net proceeds of $1.0 million, net of $0.2 million in commissions and offering expenses paid.

In May 2015, in connection with the Arkoma Acquisition (see “Recent Developments”), we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of approximately $49.7 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our revolving credit facility.

In April 2015, we issued 255,000 of its Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of approximately $6.0 million. We pay cumulative distributions on a quarterly basis at an annual rate of $2.6875 per unit or at a rate of 10.75% per annum of the stated liquidation preference of $25.00.

In October 2014, in connection with the Eagle Ford Acquisition, we issued 3,200,000 Class D Preferred Units at a public offering price of $25.00 per unit, yielding net proceeds of approximately $77.3 million from the offering, after deducting underwriting discounts and estimated offering expenses. We used the net proceeds from the offering to fund a portion of the Eagle Ford Acquisition. On March 31, 2015, to partially pay our portion of the quarterly installment related to the Eagle Ford Acquisition, we issued an additional 800,000 Class D Preferred Units directly to the seller at a value of $25.00 per unit. On January 15, 2015, we paid an initial quarterly distribution of $0.616927 per Class D Preferred Unit for the extended period from October 2, 2014 through January 14, 2015 to holders of record as of January 2, 2015. We will pay distributions on a quarterly basis, at an annual rate of $2.15625 per unit, or 8.625% of the $25.00 liquidation preference.

The Class D and Class E Preferred Units rank senior to our common units and Class C Preferred Units with respect to the payment of distributions and distributions upon a liquidation event. The Class D and Class E Preferred Units have no stated maturity and are not subject to mandatory redemption or any sinking fund and will remain outstanding indefinitely unless repurchased or redeemed by us or converted into our common units in connection with a change in control. At any time on or after October 15, 2019 for the Class D Preferred Units and April 15, 2020 for the Class E Preferred Units, we may, at our option, redeem such preferred units in whole or in part, at a redemption price of $25.00 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, we may redeem such preferred units following certain changes of control, as described in the respective Certificates of Designation. If we do not exercise this redemption option upon a change of control, then holders of such preferred units will have the option to convert the preferred units into a number of our common units as set forth in the respective Certificates of Designation. If we exercise any of our redemption rights relating to such preferred units, the holders will not have the conversion right described above with respect to the preferred units called for redemption.

In August 2014, we entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the Agents. Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to $100.0 million. Sales of common 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, including sales made directly on the New York Stock Exchange, the existing trading market for the common 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 units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. During the three months ended September 30, 2015, we issued 5,519,110 common limited partner units under the equity distribution program for net proceeds of $18.6 million, net of $0.3 million in commissions and offering expenses paid. During the nine months ended September 30, 2015, we issued 8,404,934 common limited partner units under the equity distribution program for net proceeds of $40.0 million, net of $1.0 million in commissions and offering expenses paid.

In May 2014, in connection with the Rangely Acquisition, we issued 15,525,000 of our common limited partner units (including 2,025,000 units pursuant to an over-allotment option) in a public offering at a price of $19.90 per unit, yielding net proceeds of approximately $297.3 million.

In March 2014, in connection with the GeoMet Acquisition, we issued 6,325,000 of our common limited partner units (including 825,000 units pursuant to an over-allotment option) in a public offering at a price of $21.18 per unit, yielding net proceeds of approximately $129.0 million.

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, 2014, 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” within this section, recent increases in natural gas and oil drilling have driven an increase in the supply of natural gas and oil and put a downward pressure on domestic prices. Further declines in commodity prices may result in additional impairment charges in future periods.

There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and nine months ended September 30, 2015 and 2014.

For the three and nine months ended September 30, 2015, we recognized $740.2 million of asset impairment related to oil and gas properties in the Barnett, Coal-bed Methane, Southern Appalachia, Marcellus and Mississippi Lime operating areas, which were impaired due to lower forecasted commodity prices, reduced by $68.0 million of future hedge gains reclassified from accumulated other comprehensive income. There were no impairments of proved gas and oil properties for the three and nine months ended September 30, 2014.

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, 2014.

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, 2015 and 2014. During the year ended December 31, 2014, we recorded an $18.1 million goodwill non-cash impairment loss within asset impairment on our consolidated statement of operations related to an impairment of goodwill in our gas and oil production reporting unit due to a decline in overall commodity prices.

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 year ended December 31, 2014, we completed the Eagle Ford, Rangely and GeoMet acquisitions. 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, oil and natural gas liquids 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, oil and natural gas liquids 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, 2014, we engaged independent third-party reserve engineers to prepare reports 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, oil and natural gas liquids reserves are inherently imprecise. Actual future production, natural gas, oil and natural gas liquids prices, revenues, development expenditures, operating expenses and quantities of recoverable natural gas, oil and natural gas liquids 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, oil and natural gas liquids 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 estimate the cost of future dismantlement, restoration, reclamation and abandonment of our operating assets.

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 interest rate cap 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, 2015. 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, 2015, $563.0 million was outstanding under our revolving credit facility and $243.4 million was outstanding under our term loan 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, 2016 by approximately $8.1 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, 2016 of approximately $9.0 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 option 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, while ethane, propane, butane and iso butane contracts are priced based on the respective Mt. Belvieu price.

At September 30, 2015, 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)
2015	13,611,000	$ 4.193
2016	53,546,300	$ 4.229
2017	49,920,000	$ 4.219
2018	40,800,000	$ 4.170
2019	15,960,000	$ 4.017

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Floor and Cap (per MMBtu)(1)
2015	Puts purchased	600,000	$ 3.934
2015	Calls sold	600,000	$ 4.634

Natural Gas – Put Options – Drilling Partnerships

Production Period Ending December 31,	Option Type	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)
2015	Puts purchased	360,000	$ 4.000
2016	Puts purchased	1,440,000	$ 4.150

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)[(1)]	Average Fixed Price (per MMBtu)[(1)]
2015	1,200,000	$ (0.090)

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Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2015	1,260,000	$ 1.923

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2015	2,016,000	$ 1.016

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2015	378,000	$ 1.248

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)(1)	Average Fixed Price (per Gal)(1)
2015	378,000	$ 1.263

Natural Gas Liquids – Crude Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)
2016	84,000	$ 85.651

2017	60,000	$ 83.780

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]
2015	487,500	$ 87.592
2016	1,557,000	$ 81.471
2017	1,140,000	$ 77.285
2018	1,080,000	$ 76.281
2019	540,000	$ 68.371

(1) “MMBtu” represents million British Thermal Units; “Bbl” represents barrels; “Gal” represents gallons.

ITEM 4: CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure 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 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 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 Chief Executive Officer and Chief Financial Officer concluded that, as of September 30, 2015, 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.

ITEM 6: EXHIBITS

Exhibit No.	Description
1.1	Underwriting Agreement dated April 7, 2015 by and among Atlas Resource Partners, L.P. and the underwriters named therein[26]
1.2	Underwriting Agreement dated May 19, 2015 by and among Atlas Resource Partners, L.P. and the underwriters named therein[40]
2.1	Purchase and Sale Agreement, dated as of May 6, 2014. 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	Asset Purchase Agreement, dated as of February 13, 2014, by and among GeoMet, Inc., GeoMet Operating Company, Inc., GeoMet Gathering Company, LLC and ARP Mountaineer Production, LLC. The exhibits and schedules to the Asset Purchase Agreement have been omitted pursuant to Item 601(b) of Regulation S-K. A copy of the omitted exhibits and schedules will be furnished to the U.S. Securities and Exchange Commission upon request[25]
2.3(a)	Purchase and Sale Agreement, dated September 24, 2014, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC 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 [30]
2.3(b)	First Amendment to Purchase and Sale Agreement dated October 27, 2014, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. [34]
2.3(c)	Second Amendment to Purchase and Sale Agreement dated March 31, 2015, by and between Cinco Resources, Inc., Cima Resources, LLC, ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Resource Partners, L.P. [37]
2.4(a)	Shared Acquisition and Operating Agreement, dated September 24, 2014, by and among ARP Eagle Ford, LLC and Atlas Growth Eagle Ford, LLC. The schedules to the Shared Acquisition and Operating 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 [30]

2.4(b)

Amended and Restated Shared Acquisition and Operating Agreement, effective as of September 24, 2014, by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC. The schedules to the Amended and Restated Shared Acquisition and Operating 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.

2.4(c)

Addendum #2 to the Amended and Restated Shared Acquisition and Operating Agreement by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC, effective as of July 1, 2015. The schedules to Addendum #2 to the Amended and Restated Shared Acquisition and Operating 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.

2.4(d)

Addendum #3 to the Amended and Restated Shared Acquisition and Operating Agreement by and among ARP Eagle Ford, LLC, Atlas Growth Eagle Ford, LLC and Atlas Eagle Ford Operating Company, LLC, effective as of September 30, 2015. The schedules to Addendum #3 to the Amended and Restated Shared Acquisition and Operating 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.

Exhibit No.	Description
2.5	Purchase and Sale Agreement, dated May 18, 2015, by and between New Atlas Holdings, LLC and ARP Production Company, LLC. 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 [40]
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[6]
3.2(d)	Amendment No. 3 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of October 2, 2014[31]
3.2(e)	Amendment No. 4 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of November 3, 2014[33]
3.2(f)	Amendment No. 5 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of February 27, 2015 [39]
3.2(g)	Amendment No. 6 to Amended and Restated Agreement of Limited Partnership of Atlas Resource Partners, L.P. dated as of April 14, 2015 [38]
3.3(a)	Certificate of Formation of Atlas Resource Partners GP, LLC[2]
3.3(b)	Certificate of Amendment to Certificate of Formation of Atlas Resource Partners GP, LLC dated as of November 3, 2014[33]
3.4(a)	Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC[24]

3.4(b)	Amendment No. 1 to Second Amended and Restated Limited Liability Company Agreement of Atlas Resource Partners GP, LLC dated as of November 3, 2014[33]
4.1(a)	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]
4.1(b)	Supplemental Indenture dated as of June 2, 2014 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[29]
4.1(c)	Second Supplemental Indenture dated as of July 23, 2015, among Atlas Resource Partners Holdings, LLC (f/k/a 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[42]
4.2(a)	Indenture dated as of July 30, 2013, by and between Atlas Resource Escrow Corporation and Wells Fargo Bank, National Association[22]
4.2(b)	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]

Exhibit No.	Description
4.2(c)	Second Supplemental Indenture dated as of October 14, 2014, 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[32]
4.2(d)	Third Supplemental Indenture dated as of July 23, 2015, by and among Atlas Resource Partners, L.P., Atlas Resource Partners Holdings, LLC (f/k/a Atlas Energy Holdings Operating Company, LLC), Atlas Resource Finance Corporation, the guarantors named therein and Wells Fargo Bank, National Association[42]
4.3	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]
4.4	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[6]
4.5	Warrant to Purchase Common Units[6]
4.6	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of 8.625% Class D Cumulative Redeemable Perpetual Preferred Units, dated as of October 2, 2014[31]
4.7	Certificate of Designation of the Powers, Preferences and Relative, Participating, Optional and Other Special Rights and Qualifications, Limitations and Restrictions thereof of Class E Cumulative Redeemable Perpetual Preferred Units, dated as of April 14, 2015[38]
10.1	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]
10.2(a)	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[6]
10.2(b)	First Amendment to Second Amended and Restated Credit Agreement dated December 6, 2013 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[28]

10.2(c)	Third Amendment to Second Amended and Restated Credit Agreement dated June 30, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(29)]
10.2(d)	Fourth Amendment to Second Amended and Restated Credit Agreement dated September 24, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(30)]
10.2(e)	Fifth Amendment to Second Amended and Restated Credit Agreement dated November 24, 2014 among Atlas Resource Partners, L.P., the lenders party thereto and Wells Fargo Bank, N.A., as administrative agent for the lenders[(10)]
10.2(f)	Sixth Amendment to Second Amended and Restated Credit Agreement, dated February 23, 2015, by and among Atlas Resource Partners, L.P., Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto[(36)]
10.3	Second Lien Credit Agreement, dated February 23, 2015, by and among Atlas Resource Partners, L.P., Wilmington Trust, National Association, as administrative agent, and the lenders party thereto[(36)]

Exhibit No.	Description
10.4	2012 Long-Term Incentive Plan of Atlas Resource Partners, L.P. [4]
10.5	Form of Phantom Unit Grant Agreement under 2012 Long-Term Incentive Plan[8]
10.6	Form of Option Grant Agreement under 2012 Long-Term Incentive Plan[8]
10.7	Form of Phantom Unit Grant Agreement for Non-Employee Directors under 2012 Long-Term Incentive Plan[8]
10.8	Registration Rights Agreement, dated March 31, 2015, by and between Cinco Resources, Inc. and Atlas Resource Partners, L.P.[37]
10.9	Amended and Restated Registration Rights Agreement, dated as of July 31, 2013, between Atlas Resource Partners, L.P., Wells Fargo Bank, National Association and the lenders named in the Amended and Restated Credit Agreement dated July 31, 2013 by and among Atlas Energy, L.P. and the lenders named therein[39]
10.10	Registration Rights Agreement dated as of June 2, 2014, by and among Atlas Resource Partners, L.P., Atlas Energy Holdings Operating Company, LLC, Atlas Resource Finance Corporation, the guarantors named therein Wells Fargo Securities, LLC and Deutsche Bank Securities, Inc [29]
10.11	Registration Rights Agreement dated as of July 31, 2013, by and among Atlas Energy, L.P. and Atlas Resource Partners, L.P. [6]
10.12	Registration Rights Agreement dated as of October 14, 2014, 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 Securities, LLC, for itself and on behalf of the Initial Purchasers [32]
10.13	Distribution Agreement dated as of August 29, 2014, between Atlas Resource Partners, L.P. and Deutsche Bank Securities Inc., as representative of the several[35]
10.14	Distribution Agreement dated as of August 19, 2015, between Atlas Resource Partners, L.P. and MLV and Co. LLC[43]

10.15	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Edward E. Cohen, dated September 4, 2015[(44)]
10.16	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Jonathan Z. Cohen, dated September 4, 2015[(44)]
10.17	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Daniel C. Herz, dated September 4, 2015[(44)]
10.18	Employment Agreement among Atlas Energy Group, LLC, Atlas Resource Partners, L.P. and Mark Schumacher, dated September 4, 2015[(44)]
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

Exhibit No.	Description
99.1	Voting Agreement, dated as of February 13, 2014, by and among ARP Mountaineer Production, LLC, Atlas Resource Partners, L.P. and each of the persons listed on Annex I thereto(25)
99.2	Atlas Resource Partners, L.P. - Partnership Agreement and Distribution Policy(45)
99.3	Rangely Summary Reserve Report of Cawley, Gillespie, and Associates, Inc.(41)
101.INS	XBRL Instance Document(27)
101.SCH	XBRL Schema Document(27)
101.CAL	XBRL Calculation Linkbase Document(27)
101.LAB	XBRL Label Linkbase Document(27)
101.PRE	XBRL Presentation Linkbase Document(27)
101.DEF	XBRL Definition Linkbase Document(27)

(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 our Current Report on Form 8-K filed on August 6, 2013
(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 November 25, 2014.
(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 May 7, 2014.
(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 Atlas Energy's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013.
(24) Previously filed as an exhibit to our quarterly report on Form 10-Q for the quarter ended September 30, 2013.
(25) Previously filed as an exhibit to our current report on Form 8-K filed on February 18, 2014.
(26) Previously filed as an exhibit to our current report on Form 8-K filed on April 13, 2015.
(27) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is "unaudited" or "unreviewed".
(28) Previously filed as an exhibit to our Annual Report on Form 10-K filed for the year ended December 31, 2013.
(29) Previously filed as an exhibit to our current report on Form 8-K filed on June 3, 2014.
(30) Previously filed as an exhibit to our current report on Form 8-K filed on September 30, 2014.
(31) Previously filed as an exhibit to our current report on Form 8-K filed on October 2, 2014.
(32) Previously filed as an exhibit to our current report on Form 8-K filed on October 15, 2014.
(33) Previously filed as an exhibit to our current report on Form 8-K filed on November 5, 2014.
(34) Previously filed as an exhibit to our current report on Form 8-K filed on November 6, 2014.
(35) Previously filed as an exhibit to our current report on Form 8-K filed on August 29, 2014.
(36) Previously filed as an exhibit to our current report on Form 8-K filed on February 23, 2015.

(37) Previously filed as an exhibit to our current report on Form 8-K filed on April 6, 2015.
(38) Previously filed as an exhibit to our registration statement on Form 8-A filed on April 14, 2015.
(39) Previously filed as an exhibit to our Annual Report on Form 10-K for the year ended December 3, 2014.
(40) Previously filed as an exhibit to our Current Report on Form 8-K filed on May 22, 2015.
(41) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 2, 2015.
(42) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2015.
(43) Previously filed as an exhibit to our Current Report on Form 8-K filed on August 19, 2015.
(44) Previously filed as an exhibit to our Current Report on Form 8-K filed on September 4, 2015.
(45) Previously filed as an exhibit to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015.

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 Energy Group, LLC, its
General Partner

Date:	November 9, 2015	By:	/s/ DANIEL C. HERZ Daniel C. Herz Chief Executive Officer of ARP
Date:	November 9, 2015	By:	/s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback Chief Financial Officer of ARP
Date:	November 9, 2015	By:	/s/ MATTHEW J. FINKBEINER Matthew J. Finkbeiner Chief Accounting Officer of ARP