Atlas Resource Partners, L.P.
Form 10-Q
August 08, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2014

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

Delaware	45-3591625
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Park Place Corporate Center One 1000 Commerce Drive, Suite 400 Pittsburgh, Pennsylvania	15275
(Address of principal executive office)	(Zip code)

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

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

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

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

Large accelerated filer 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 August 4, 2014 was 81,529,726.

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)

	June 30, 2014	December 31, 2013
ASSETS		
Current assets:		
Cash and cash equivalents	$3,993	$ 1,828
Accounts receivable	85,419	58,822
Current portion of derivative asset	255	1,891
Subscriptions receivable	16,336	47,692
Prepaid expenses and other	21,023	10,097
Total current assets	127,026	120,330
Property, plant and equipment, net	2,666,718	2,120,818
Goodwill and intangible assets, net	32,611	32,747
Long-term derivative asset	3,415	27,084
Other assets, net	51,516	42,821
	$2,881,286	$ 2,343,800
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$96,778	$ 69,346
Advances from affiliates	27,838	26,742
Liabilities associated with drilling contracts	—	49,377
Current portion of derivative liability	19,983	6,353
Accrued well drilling and completion costs	70,319	40,481
Accrued interest	22,194	20,622
Distribution payable	18,497	—
Accrued liabilities	18,622	30,794
Total current liabilities	274,231	243,715
Long-term debt	1,203,973	942,334
Asset retirement obligations	100,002	89,776
Other long-term liabilities	2,604	684
Commitments and contingencies		
Partners' Capital:		
General partner's interest	249	4,482
Preferred limited partners' interests	180,566	183,477

Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	1,132,694	852,457
Accumulated other comprehensive income (loss)	(14,209)	25,699
Total partners' capital	1,300,476	1,067,291
	$2,881,286	$ 2,343,800

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenues:				
Gas and oil production	$104,057	$47,094	$200,302	$93,158
Well construction and completion	16,336	24,851	65,713	81,329
Gathering and processing	3,758	4,463	8,226	8,048
Administration and oversight	4,166	3,391	5,895	4,476
Well services	6,365	4,864	11,844	9,680
Other, net	35	(1,337)	82	(1,317)
Total revenues	134,717	83,326	292,062	195,374
Costs and expenses:				
Gas and oil production	41,763	19,035	78,555	34,251
Well construction and completion	14,206	21,609	57,142	70,721
Gathering and processing	4,273	4,959	8,686	9,372
Well services	2,426	2,305	4,908	4,623
General and administrative	21,315	14,217	37,770	31,784
Depreciation, depletion and amortization	58,001	22,197	108,238	43,405
Total costs and expenses	141,984	84,322	295,299	194,156
Operating income (loss)	(7,267)	(996)	(3,237)	1,218
Interest expense	(13,263)	(4,508)	(26,451)	(11,397)
Gain (loss) on asset sales and disposal	9	(672)	(1,594)	(1,374)
Net loss	(20,521)	(6,176)	(31,282)	(11,553)
Preferred limited partner dividends	(4,424)	(2,071)	(8,823)	(4,028)
Net loss attributable to common limited partners and the general partner	$(24,945)	$(8,247)	$(40,105)	$(15,581)
Allocation of net income (loss) attributable to common limited partners and the general partner:				
Common limited partners' interest	$(27,322)	$(9,269)	$(44,486)	$(16,904)
General partner's interest	2,377	1,022	4,381	1,323
Net loss attributable to common limited partners and the general partner	$(24,945)	$(8,247)	$(40,105)	$(15,581)
Net loss attributable to common limited partners per unit:				
Basic and Diluted	$(0.37)	$(0.20)	$(0.66)	$(0.37)
Weighted average common limited partner units outstanding:				
Basic and Diluted	73,900	47,007	67,595	45,499

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(20,521)	$(6,176)	$(31,282)	$(11,553)
Other comprehensive income (loss):				
Changes in fair value of derivative instruments accounted for as cash flow hedges	(28,293)	42,972	(63,136)	18,028
Less: reclassification adjustment for realized (gains) losses of cash flow hedges in net loss	9,185	(2,286)	23,228	(3,279)
Total other comprehensive income (loss)	(19,108)	40,686	(39,908)	14,749
Comprehensive income (loss) attributable to common and preferred limited partners and the general partner	$(39,629)	$34,510	$(71,190)	$3,196

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENT OF PARTNERS’ CAPITAL

(in thousands, except unit data)

(Unaudited)

	General Partner’s Interest		Preferred Limited Partners’ Interest				Common Limited Partners’ Interests		Class C Common Limited Partner Warrants		Accumulated Other Comprehensi	To
	Class A Units	Amount	Class B Units	Amount	Class C Units	Amount	Units	Amount	Warrants	Amount	Income (Loss)	Pa Ca
2014	1,368,058	$4,482	3,836,554	$96,539	3,749,986	$86,938	59,448,308	$852,457	562,497	$1,176	$25,699	$
f	449,811	—	—	—	—	—	21,850,000	426,393	—	—	—	4
and nits ntive	—	—	—	—	—	—	190,746	3,677	—	—	—	3
ns	—	(1,279)	—	(742)	—	(725)	—	(15,751)	—	—	—	(
ns nd tners neral n	—	(7,335)	—	(5,192)	—	(5,075)	—	(88,368)	—	—	—	(
on nits ntive	—	—	—	—	—	—	—	(1,228)	—	—	—	(
e	—	4,381	—	4,461	—	4,362	—	(44,486)	—	—	—	(
sive	—	—	—	—	—	—	—	—	—	—	(39,908)	(
014	1,817,869	$249	3,836,554	$95,066	3,749,986	$85,500	81,489,054	$1,132,694	562,497	$1,176	$(14,209)	$

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(Unaudited)

	Six Months Ended June 30,	
	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$(31,282)	$(11,553)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	108,238	43,405
Loss on asset sales and disposal	1,594	1,374
Non-cash compensation expense	4,353	7,249
Amortization of deferred financing costs	3,711	5,797
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	(3,410)	11,880
Accounts payable and accrued liabilities	(38,163)	(90,097)
Net cash provided by (used in) operating activities	45,041	(31,945)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(94,555)	(130,052)
Net cash paid for acquisitions	(517,453)	—
Other	(148)	(4,056)
Net cash used in investing activities	(612,156)	(134,108)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under credit facilities	838,000	249,000
Repayments under credit facilities	(676,000)	(600,425)
Net proceeds from issuance of long-term debt	97,500	267,811
Distributions paid to unitholders	(105,970)	(48,897)
Net proceeds from issuance of common limited partner units	426,393	320,221
Deferred financing costs, distribution equivalent rights and other	(10,643)	(1,892)
Net cash provided by financing activities	569,280	185,818
Net change in cash and cash equivalents	2,165	19,765
Cash and cash equivalents, beginning of year	1,828	23,188
Cash and cash equivalents, end of period	$3,993	$42,953

See accompanying notes to consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

June 30, 2014

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

Atlas Resource Partners, L.P. (the "Partnership") is a publicly traded Delaware master-limited partnership (NYSE: ARP) and an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL") with operations in basins across the United States. The Partnership sponsors and manages tax-advantaged investment partnerships (the "Drilling Partnerships"), in which it coinvests, to finance a portion of its natural gas, crude oil and NGL production activities. At June 30, 2014, Atlas Energy, L.P. ("ATLS"), a publicly traded master-limited partnership (NYSE: ATLS), owned 100% of the general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls the Partnership and an approximate 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in the Partnership.

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

The accompanying consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2013 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, 2013. 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 six months ended June 30, 2014 may not necessarily be indicative of the results of operations for the full year ending December 31, 2014.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

The Partnership's consolidated balance sheets at June 30, 2014 and December 31, 2013 and the consolidated statements of operations for the three and six months ended June 30, 2014 and 2013 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.

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 as further explained under the heading "Property, Plant and Equipment" elsewhere within this note.

Use of Estimates

The preparation of the Partnership's consolidated financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities that exist at the date of the Partnership's consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. The Partnership's consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, asset impairments, fair value of derivative instruments, the probability of forecasted transactions and the allocation of purchase price to the fair value of assets acquired and liabilities assumed. Actual results could differ from those estimates.

The natural gas industry principally conducts its business by processing actual transactions as many as 60 days after the month of delivery. Consequently, the most recent two months' financial results were recorded using estimated volumes and contract market prices. Differences between estimated and actual amounts are recorded in the following month's financial results. Management believes that the operating results presented for the three and six months ended June 30, 2014 and 2013 represent actual results in all material respects (see "Revenue Recognition").

Receivables

Accounts receivable on the consolidated balance sheets consist solely of the trade accounts receivable associated with the Partnership's operations. In evaluating the realizability of its accounts receivable, the Partnership's management performs ongoing credit evaluations of its customers and adjusts credit limits based upon payment history and the customer's current creditworthiness, as determined by management's review of the Partnership's customers' credit information. The Partnership extends credit on sales on an unsecured basis to many of its customers. At June 30, 2014 and December 31, 2013, the Partnership had recorded no allowance for uncollectible accounts receivable on its consolidated balance sheets.

Inventory

The Partnership had $9.2 million and $4.6 million of inventory at June 30, 2014 and December 31, 2013, 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 which generally do not extend the useful life of an asset for two years or more through the replacement of critical components are expensed as incurred. Major renewals and improvements which generally extend the useful life of an asset for two years or more through the replacement of critical components are capitalized. Depreciation and amortization expense is based on cost less the estimated salvage value primarily using the straight-line method over the asset's estimated useful life. When entire pipeline systems, gas plants or other property and equipment are retired or sold, any gain or loss is included in the Partnership's results of operations.

The Partnership follows the successful efforts method of accounting for oil and gas producing activities. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs to enhance or evaluate development of proved fields or areas are capitalized. All other geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Oil and NGLs are converted to gas equivalent basis ("Mcfe") at the rate of one barrel to 6 Mcf of natural gas. Mcf is defined as one thousand cubic feet.

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

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

Impairment of Long-Lived Assets

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

The review of the Partnership's oil and gas properties is done on a field-by-field basis by determining if the historical cost of proved properties less the applicable accumulated depletion, depreciation and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Partnership's plans to continue to produce and develop proved reserves. Expected future cash 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 futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets.

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

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

The Partnership's method of calculating its reserves may result in reserve quantities and values which are greater than those which would be calculated by the Drilling Partnerships, which the Partnership sponsors and owns an interest in but does not control. The Partnership's reserve quantities include reserves in excess of its proportionate share of reserves in Drilling Partnerships, which the Partnership may be unable to recover due to the Drilling Partnerships' legal structure. The Partnership may have to pay additional consideration in the future as a 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 partner agreement. In general, the Partnership will seek consent from the Drilling Partnership's limited partners to acquire the well interests from the Drilling Partnership based upon the Partnership's determination of fair market value.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment charges are recorded if conditions indicate the

Partnership will not explore the acreage prior to expiration of the applicable leases or if it is determined that the carrying value of the properties is above their fair value. During the year ended December 31, 2013, the Partnership recognized $13.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet, primarily for its unproved acreage in the Chattanooga and New Albany Shales. There were no impairments of unproved gas and oil properties recorded by the Partnership for the three and six months ended June 30, 2014 and 2013.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. During the year ended December 31, 2013, the Partnership recognized $24.5 million of asset impairments related to its gas and oil properties within property, plant and equipment, net on its consolidated balance sheet for its shallow natural gas wells in the New Albany Shale. There were no impairments of proved gas and oil properties recorded by the Partnership for the three and six months ended June 30, 2014 and 2013.

The impairments of proved and unproved properties during the year ended December 31, 2013 related to the carrying amounts of these gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2013 and management's intention not to drill on certain expiring unproved acreage. The estimate of the fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

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 6.0% and 5.9% for the three months ended June 30, 2014 and 2013, respectively, and 5.8% and 6.0% for the six months ended June 30, 2014 and 2013, respectively. The aggregate amount of interest capitalized by the Partnership was $3.1 million and $3.4 million for the three months ended June 30, 2014 and 2013, respectively, and $5.7 million and $6.9 million for the six months ended June 30, 2014 and 2013, respectively.

Intangible Assets

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

The following table reflects the components of intangible assets being amortized at June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013	Estimated Useful Lives In Years
Gross Carrying Amount	$14,344	$ 14,344	13
Accumulated Amortization	(13,517)	(13,381)	
Net Carrying Amount	$827	$ 963	

Amortization expense on intangible assets was $0.1 million for both the three months ended June 30, 2014 and 2013, and $0.2 million for both the six months ended June 30, 2014 and 2013. Aggregate estimated annual amortization expense for all of the contracts described above for the next five years ending December 31 is as follows: 2014 - $0.3 million; 2015 - $0.2 million; 2016 - $0.1 million, 2017 - $0.1 million and 2018 - $0.1 million.

Goodwill

At June 30, 2014 and December 31, 2013, the Partnership had $31.8 million of goodwill recorded in connection with its prior consummated acquisitions. No changes in the carrying amount of goodwill were recorded for the three and six months ended June 30, 2014 and 2013.

The Partnership tests goodwill for impairment at each year end by comparing its reporting units' estimated fair values to carrying values. Because quoted market prices for the reporting units are not available, the Partnership's management must apply judgment in determining the estimated fair value of these reporting units. The Partnership's management uses all available information to make these fair value determinations, including the present values of expected future cash flows using discount rates commensurate with the risks involved in the Partnership's assets and the available market data of the industry group. A key component of these fair value determinations is a reconciliation of the sum of the fair value calculations to the Partnership's market capitalization. The observed market prices of individual trades of an entity's equity securities (and thus its computed market capitalization) may not be representative of the fair value of the entity as a whole. Substantial value may arise from the ability to take advantage of synergies and other benefits that flow from control over another entity. Consequently, measuring the fair value of a collection of assets and liabilities that operate together in a controlled entity is different from measuring the fair value of that entity on a stand-alone basis. In most industries, including the Partnership's, an acquiring entity typically is willing to pay more for equity securities that give it a controlling interest than an investor would pay for a number of equity securities representing less than a controlling interest. Therefore, once the above fair value calculations have been determined, the Partnership's management also considers the inclusion of a control premium within the calculations. This control premium is judgmental and is based on, among other items, observed acquisitions in the Partnership's industry. The resultant fair values calculated for the reporting units are compared to observable metrics on large mergers and acquisitions in the Partnership's industry to determine whether those valuations appear reasonable in management's judgment. Management will continue to evaluate goodwill at least annually or when impairment indicators arise. During the three and six months ended June 30, 2014 and 2013, no impairment indicators arose, and no goodwill impairments were recognized by the Partnership.

Asset Retirement Obligations

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

Income Taxes

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

The Partnership evaluates tax positions taken or expected to be taken in the course of preparing the Partnership's tax returns and disallows the recognition of tax positions not deemed to meet a "more-likely-than-not" threshold of being sustained by the applicable tax authority. The Partnership's management does not believe it has any tax positions taken within its consolidated financial statements that would not meet this threshold. The Partnership's policy is to reflect interest and penalties related to uncertain tax positions, when and if they become applicable. The Partnership has not recognized any potential interest or penalties in its consolidated financial statements for the three and six months ended June 30, 2014 and 2013.

The Partnership files Partnership Returns of Income in the U.S. and various state jurisdictions. With few exceptions, the Partnership is no longer subject to income tax examinations by major tax authorities for years prior to 2010. The Partnership is not currently being examined by any jurisdiction and is not aware of any potential examinations as of June 30, 2014.

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 loss allocated to the common limited partners for purposes of calculating net loss attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Net loss	$(20,521)	$(6,176)	$(31,282)	$(11,553)
Preferred limited partner dividends	(4,424)	(2,071)	(8,823)	(4,028)
Net loss attributable to common limited partners and the general partner	(24,945)	(8,247)	(40,105)	(15,581)
Less: General partner's interest	(2,377)	(1,022)	(4,381)	(1,323)
Net loss attributable to common limited partners	(27,322)	(9,269)	(44,486)	(16,904)
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	$(27,322)	$(9,269)	$(44,486)	$(16,904)

[1] Net income attributable to common limited partners' ownership interests is allocated to the phantom units on a pro-rata basis (weighted average phantom units outstanding as a percentage of the sum of the weighted average phantom units and common limited partner units outstanding). For the three months ended June 30, 2014 and 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 724,000 and 923,000 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 six months ended June 30, 2014 and 2013, net loss attributable to common limited partners' ownership interest is not allocated to approximately 772,000 and 960,000 phantom units, respectively, because the contractual terms of the phantom units as participating securities do not require the holders to share in the losses of the entity.

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Weighted average number of common limited partner units - basic	73,900	47,007	67,595	45,499
Add effect of dilutive incentive awards[1]	—	—	—	—

Add effect of dilutive convertible preferred limited partner units and warrants[(2)]	—	—	—	—
Weighted average number of common limited partner units - diluted	73,900	47,007	67,595	45,499

(1) For the three months ended June 30, 2014 and 2013, approximately 724,000 units and 923,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the six months ended June 30, 2014 and 2013, approximately 772,000 units and 960,000 units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive.

(2) For the three and six months ended June 30, 2014 and 2013, 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 six months ended June 30, 2014, potential common limited partner units issuable upon conversion of the Partnership's 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. For the three and six months ended June 30, 2014, potential common limited partner units issuable upon 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.

Revenue Recognition

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

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

The Partnership accrues unbilled revenue due to timing differences between the delivery of natural gas, NGLs and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Partnership's records and management estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices (see "Use of Estimates" for further description). The Partnership had unbilled revenues of $83.3 million and $55.3 million at June 30, 2014 and December 31, 2013, respectively, which were included in accounts receivable within the Partnership's consolidated balance sheets.

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 Shale and the Chattanooga Shale. 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 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%.

Comprehensive Income (Loss)

Comprehensive income (loss) includes net income (loss) and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net income (loss). These changes, other than net income (loss), are referred to as "other comprehensive income (loss)" on the Partnership's consolidated financial statements, and at June 30, 2014, 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 Adopted Accounting Standards

In July 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-11, Income Taxes (Topic 740) – Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists ("Update 2013-11"), which, among other changes, requires an entity to present an unrecognized tax benefit as a liability and not net with deferred tax assets when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date to settle any additional income taxes under the tax law of the applicable jurisdiction that would result from the disallowance of a tax position or when the tax law of the applicable tax jurisdiction does not require, and the entity does not intend to, use the deferred tax asset for such purpose. These requirements are effective for interim and annual reporting periods beginning after December 15, 2013. Early adoption was permitted. These amendments should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application was permitted. The Partnership adopted the requirements of Update 2013-11 upon its effective date of January 1, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

In February 2013, the FASB issued ASU 2013-04, Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is Fixed at the Reporting Date (“Update 2013-04”). Update 2013-04 provides guidance for the recognition, measurement and disclosure of obligations resulting from joint and several liability arrangements, for which the total amount of the obligation within the scope of this guidance is fixed at the reporting date, except for obligations addressed within existing guidance in U.S. GAAP. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations and settled litigation and judicial rulings. Update 2013-04 requires an entity to measure joint and several liability arrangements, for which the total amount of the obligation is fixed at the reporting date as the sum of the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors and any additional amount the reporting entity expects to pay on behalf of its co-obligors. In addition, Update 2013-04 provides disclosure guidance on the nature and amount of the obligation as well as other information. Update 2013-04 is effective for fiscal years and interim periods within those years, beginning after December 15, 2013. The Partnership adopted the requirements of Update 2013-04 upon its effective date of January 1, 2014, and it had no material impact on its financial position, results of operations or related disclosures.

Recently Issued Accounting Standards

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. Earlier 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, 2016, 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, 2017, 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 for approximately $420.0 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 (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 $11.5 million of transaction fees which were included with common limited partners’ interests for the six months ended June 30, 2014 on the Partnership’s consolidated balance sheet. All other costs associated with the acquisition of assets were expensed as incurred. Due to the recent date of the acquisition, the accounting for the business combination is based upon preliminary data that remains subject to adjustment and could further change as the Partnership continues to evaluate the facts and circumstances that existed as of the acquisition date.

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

Assets:	
Prepaid expenses and other	$4,041
Property, plant and equipment	417,264
Total current assets	$421,305
Liabilities:	
Asset retirement obligation	1,305
Total liabilities assumed	1,305
Net assets acquired	$420,000

EP Energy Acquisition

On July 31, 2013, the Partnership completed the acquisition of assets from EP Energy E&P Company, L.P. (“EP Energy”) for approximately $709.6 million in cash, net of purchase price adjustments (the “EP Energy Acquisition”). The purchase price was funded through borrowings under the Partnership’s revolving credit facility, the issuance of the Partnership’s 9.25% senior notes due August 15, 2021 (see Note 7), and the issuance of 14,950,000 common limited partner units and 3,749,986 newly created Class C convertible preferred units (see Note 12). The assets acquired included coal-bed methane producing natural gas assets in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama and the County Line area of Wyoming. The EP Energy Acquisition had an effective date of May 1, 2013. The Partnership’s consolidated financial statements reflected the operating results of the acquired business commencing July 31, 2013 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 $12.1 million of transaction fees which were included within common limited partners' interests for the year ended December 31, 2013 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 fair values at the date of the acquisition (in thousands):

Assets:	
Prepaid expenses and other	$5,268
Property, plant and equipment	723,842
Total current assets	$729,110
Liabilities:	
Accounts payable	2,747
Asset retirement obligation	16,728
Total liabilities assumed	19,475
Net assets acquired	$709,635

Pro Forma Financial Information

The following data presents pro forma revenues, net income (loss) and basic and diluted net income (loss) per unit for the Partnership as if the Rangely and EP Energy acquisitions, including the related borrowings, net proceeds from the issuances of debt and issuances of common and preferred units had occurred on January 1, 2013. The Partnership prepared these pro forma unaudited financial results for comparative purposes only; they may not be indicative of the results that would have occurred if the Rangely and EP Energy acquisitions and related offerings had occurred on January 1, 2013 or the results that will be attained in future periods (in thousands, except per share data; unaudited):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Total revenues and other	$157,613	$148,591	$338,063	$317,366
Net income (loss)	(2,433)	22,624	(2,409)	35,823
Net income (loss) attributable to common limited partners	(9,596)	16,971	(16,190)	25,665
Net income (loss) attributable to common limited partners per unit:				
Basic	$(0.12)	$0.21	$(0.20)	$0.31
Diluted	$(0.12)	$0.20	$(0.20)	$0.31

Other Acquisitions

On May 12, 2014, the Partnership completed the acquisition of certain assets from GeoMet, Inc. (“GeoMet”) (OTCQB: GMET) for approximately $107.0 million in cash with an effective date of January 1, 2014. The assets include coal-bed methane producing natural gas assets in West Virginia and Virginia.

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

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NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2014	December 31, 2013	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$326,764	$ 320,459	
Pre-development costs	4,724	4,367	
Wells and related equipment	2,792,248	2,164,760	
Total proved properties	3,123,736	2,489,586	
Unproved properties	214,715	211,536	
Support equipment	31,252	23,005	
Total natural gas and oil properties	3,369,703	2,724,127	
Pipelines, processing and compression facilities	43,093	42,949	2 – 40
Rights of way	829	830	20 – 40
Land, buildings and improvements	8,970	9,462	3 – 40
Other	16,992	15,318	3 – 10
	3,439,587	2,792,686	
Less – accumulated depreciation, depletion and amortization	(772,869)	(671,868)	
	$2,666,718	$ 2,120,818	

During the six months ended June 30, 2014, the Partnership recognized $1.6 million of loss on asset disposal primarily related to the sale of producing wells in the Niobrara Shale in connection with the settlement of a third party farmout agreement. During the three and six months ended June 30, 2013, the Partnership recognized $0.7 million and $1.4 million of loss on asset disposal pertaining to its decision not to drill wells on leasehold property that expired in such periods in Indiana and Tennessee.

During the year ended December 31, 2013, the Partnership recognized $38.0 million of asset impairments related to its oil and gas properties within property, plant and equipment, net on its consolidated balance sheet primarily for its shallow natural gas wells in the New Albany Shale and unproved acreage in the Chattanooga and New Albany Shales. These impairments related to the carrying amounts of gas and oil properties being in excess of the Partnership's estimate of their fair values at December 31, 2013, and management's intention not to drill on certain expiring unproved acreage. The estimate of fair values of these gas and oil properties was impacted by, among other factors, the deterioration of natural gas prices at the date of measurement.

NOTE 5 – OTHER ASSETS

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

	June 30, 2014	December 31, 2013

Deferred financing costs, net of accumulated amortization of $15,660 and $11,948 at June 30, 2014 and December 31, 2013, respectively	$42,534	$ 35,292
Notes receivable	3,875	3,978
Long-term derivative asset receivable from Drilling Partnerships	947	863
Other	4,160	2,688
	$51,516	$ 42,821

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 $1.9 million and $1.2 million for the three months ended June 30, 2014 and 2013, respectively, and $3.7 million and $2.6 million for the six months ended June 30, 2014 and 2013, respectively, which was recorded within interest expense on the Partnership's consolidated statements of operations. During the three and six months ended June 30, 2014, the Partnership recognized $8.3 million of deferred financing costs relating to the amendment to its revolving credit facility in connection with the Rangely Acquisition (see Note 7). During the six months ended June 30, 2013, the Partnership recognized $3.2 million for accelerated amortization of deferred financing costs associated with the retirement of its then-existing term loan facility and a portion of the outstanding indebtedness under its revolving credit facility with a portion of the proceeds from its issuance of its 7.75% senior notes due 2021 (see Note 7). There was no accelerated amortization of deferred financing costs during the three months ended June 30, 2014 and 2013 and during the six months ended June 30, 2014.

At June 30, 2014 and December 31, 2013, the Partnership had notes receivable with certain investors of its Drilling Partnerships, which were included within other assets, net on the Partnership's consolidated balance 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 and six months ended June 30, 2014, approximately $23,000 and $46,000 of interest income, respectively, was recognized within other, net on the Partnership's consolidated statements of operations. For the three and six months ended June 30, 2013, there was approximately $25,000 of interest income recognized within other, net on the Partnership's consolidated statements of operations. At June 30, 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 could 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 June 30, 2014, the Drilling Partnerships had $55.7 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 June 30, 2014, the Partnership withheld approximately $0.7 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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Asset retirement obligations, beginning of period	$91,389	$66,386	$89,776	$64,794
Liabilities incurred	7,326	599	7,855	1,244
Liabilities settled	(200)	(216)	(417)	(223)
Accretion expense	1,487	963	2,788	1,917
Asset retirement obligations, end of period	$100,002	$67,732	$100,002	$67,732

The above accretion expense was included in depreciation, depletion and amortization in the Partnership's consolidated statements of operations and the asset retirement obligation liabilities were included within asset retirement obligations in the Partnership's consolidated balance sheets. During the three and six months ended June 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). During the year ended December 31, 2013, the Partnership incurred $16.7 million of future plugging and abandonment liabilities within purchase accounting for the EP Energy Acquisition it consummated during the period.

NOTE 7 - DEBT

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

	June 30, 2014	December 31, 2013
Revolving credit facility	$581,000	$ 419,000
7.75 % Senior Notes – due 2021	374,530	275,000
9.25 % Senior Notes – due 2021	248,443	248,334
Total debt	1,203,973	942,334
Less current maturities	—	—
Total long-term debt	$1,203,973	$ 942,334

Credit Facility

On June 30, 2014, in connection with the Rangely Acquisition (see Note 3), the Partnership entered into an amendment to its amended and restated credit agreement (as amended, the "Credit Agreement") with Wells Fargo Bank, National Association, as administrative agent, and the lenders party thereto. The Credit Agreement provides for a senior secured revolving credit facility with a syndicate of banks with a current borrowing base of $825.0 million and a maximum facility amount of $1.5 billion scheduled to mature in July 2018. The Partnership's borrowing base under the revolving credit facility is scheduled for semi-annual redeterminations on May 1 and November 1 of each year. Up to $20.0 million of the revolving credit facility may be in the form of standby letters of credit, of which $4.4 million was outstanding at June 30, 2014. 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 revolving 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. The Partnership is also required to pay a fee on the unused portion of the borrowing base at a rate of 0.375% 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 June 30, 2014, the weighted average interest rate on outstanding borrowings under the revolving credit facility was 2.3%.

The Credit Agreement contains customary covenants that limit the Partnership's ability to incur additional indebtedness, grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidation with other persons, or engage in certain asset dispositions including a sale of all or substantially all of its assets. The Partnership was in compliance with these covenants as of June 30, 2014. 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 4.50 to 1.0 as of the last day of the quarters ended through December 31, 2014, 4.25 to 1.0 as of the last day of the quarter ending March 31, 2015, and 4.00 to 1.0 as of the last day of fiscal quarters ending thereafter, and a ratio of current assets (as defined in the Credit Agreement) to current liabilities (as defined in the Credit Agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. Based on the definitions contained in the Partnership's Credit Agreement, at June 30, 2014, 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 3.7 to 1.0.

Senior Notes

At June 30, 2014, the Partnership had $374.5 million outstanding of its 7.75% senior unsecured notes due 2021 ("7.75% Senior Notes"), inclusive of an additional $100.0 million of such notes issued in a private placement transaction on June 2, 2014 at an offering price of 99.5% of par value, yielding net proceeds of approximately $97.5 million. The net proceeds were used to partially fund the Rangely Acquisition (see Note 3). The Partnership issued $275.0 million of its 7.75% Senior Notes in a private placement transaction at par on January 23, 2013. The 7.75% Senior Notes were presented net of a $0.5 million unamortized discount as of June 30, 2014. Interest 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 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price as defined in the governing indenture, plus accrued and unpaid interest and additional interest, if any. On and after January 15, 2017, the 7.75% Senior Notes are redeemable, in whole or in part, at a redemption price of 103.875%, decreasing to 101.938% on January 15, 2018 and 100% on January 15, 2019.

The Partnership entered into registration rights agreements with respect to the $100.0 million 7.75% Senior Notes issued in June 2014. Under the registration rights agreements, the Partnership will cause to be filed with the SEC registration statements with respect to offers to exchange the 7.75% Senior Notes for substantially identical notes that are registered under the Securities Act. The Partnership will use reasonable best efforts to cause such exchange offer registration statements to become effective under the Securities Act. In addition, the Partnership will use reasonable best efforts to cause an exchange offer to be consummated not later than 270 days after the issuance of the 7.75% Senior Notes. Under some circumstances, in lieu of, or in addition to, a registered exchange offer, the Partnership has agreed to file a shelf registration statement with respect to the 7.75% Senior Notes. The Partnership is required to pay additional interest if it fails to comply with its obligations to register the 7.75% Senior Notes within the specified time periods.

At June 30, 2014, the Partnership had $250.0 million of 9.25% senior notes due 2021 ("9.25% Senior Notes"), issued in a private placement transaction at an offering price of 99.297% of par value, yielding net proceeds of approximately $242.8 million. The net proceeds were used to partially fund the EP Energy Acquisition (see Note 3). The 9.25% Senior Notes were presented net of a $1.6 million unamortized discount as of June 30, 2014. Interest on the 9.25% Senior Notes is payable semi-annually on February 15 and August 15. At any time on or after August 15, 2017, the Partnership may redeem some or all of the 9.25% Senior Notes at a redemption price of 104.625%. On or after August 15, 2018, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 102.313% and on or after August 15, 2019, the Partnership may redeem some or all of the 9.25% Senior Notes at the redemption price of 100.0%. In addition, at any time prior to August 15, 2016, the Partnership may redeem up to 35%

of the 9.25% Senior Notes with the proceeds received from certain equity offerings at a redemption price of 109.250%. Under certain conditions, including if the Partnership sells certain assets and does not reinvest the proceeds or repay senior indebtedness or if it experiences specific kinds of changes of control, the Partnership must offer to repurchase the 9.25% Senior Notes.

In connection with the issuance of the 9.25% Senior Notes, the Partnership entered into a registration rights agreement, whereby it agreed to (a) file an exchange offer registration statement with the Securities and Exchange Commission (the "SEC") to exchange the privately issued notes for registered notes, and (b) cause the exchange offer to be consummated by July 30, 2014. On March 28, 2014, the registration statement relating to the exchange offer for the 9.25% Senior Notes was declared effective, and the exchange offer was completed on April 29, 2014.

The 9.25% Senior Notes and 7.75% Senior Notes are guaranteed by certain of the Partnership's material subsidiaries. The guarantees under the 9.25% Senior Notes and 7.75% Senior Notes are full and unconditional and joint and several, and any subsidiaries of the Partnership, other than the subsidiary guarantors, are minor. There are no restrictions on the Partnership's ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 9.25% Senior Notes and 7.75% Senior Notes contain covenants, including limitations on 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 June 30, 2014.

Total cash payments for interest by the Partnership were $26.0 million and $3.7 million for the six months ended June 30, 2014 and 2013, 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 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.

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

The Partnership enters into derivative contracts with various financial institutions, utilizing master contracts based upon the standards set by the International Swaps and Derivatives Association, Inc. These contracts allow for rights of offset at the time of settlement of the derivatives. Due to the right of offset, derivatives are recorded on the Partnership’s consolidated balance sheets as assets or liabilities at fair value on the basis of the net exposure to each counterparty. Potential credit risk adjustments are also analyzed based upon the net exposure to each counterparty. Premiums paid for purchased options are recorded on the Partnership’s consolidated balance sheets as the initial value of the options. The Partnership reflected net derivative liabilities on its consolidated balance sheets of $17.7 million and assets of $22.6 million at June 30, 2014 and December 31, 2013, respectively. Of the $14.2 million of net loss in accumulated other comprehensive income on the Partnership’s consolidated balance sheet at June 30, 2014, if the fair values of the instruments remain at current market values, the Partnership will reclassify $18.9 million of losses to gas and oil production revenue on its consolidated statement of operations over the next twelve month period as these contracts expire. Aggregate gains of $4.7 million of gas and oil production revenues will be reclassified to the Partnership’s consolidated statements of operations in later periods as the remaining contracts expire. Actual amounts that will be reclassified will vary as a result of future commodity price changes. No amounts were reclassified from other comprehensive income related to derivative instruments entered into during the three and six months ended June 30, 2014. Approximately $0.5 million of derivative loss was reclassified from other comprehensive income related to derivative instruments entered into during the three and six months ended June 30, 2013.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
(Gain) loss reclassified from accumulated other comprehensive income (loss):				
Gas and oil production revenue	$ 9,185	$ (2,286)	$ 23,228	$ (3,279)
Total	$ 9,185	$ (2,286)	$ 23,228	$ (3,279)

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

Offsetting Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Consolidated Balance Sheets	Net Amount of Assets Presented in the Consolidated Balance Sheets
As of June 30, 2014			
Current portion of derivative assets	$ 3,324	$ (3,069)	$ 255
Long-term portion of derivative assets	9,439	(6,024)	3,415
Current portion of derivative liabilities	3,004	(3,004)	—
Long-term portion of derivative liabilities	3,915	(3,915)	—
Total derivative assets	$ 19,682	$ (16,012)	$ 3,670
As of December 31, 2013			
Current portion of derivative assets	$ 2,664	$ (773)	$ 1,891
Long-term portion of derivative assets	31,146	(4,062)	27,084
Current portion of derivative liabilities	4,341	(4,341)	—
Long-term portion of derivative liabilities	122	(122)	—
Total derivative assets	$ 38,273	$ (9,298)	$ 28,975

Offsetting Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Consolidated	Net Amount of Liabilities Presented in the Consolidated

		Balance Sheets	Balance Sheets
As of June 30, 2014			
Current portion of derivative assets	$ (3,069)	$ 3,069	$ —
Long-term portion of derivative assets	(6,024)	6,024	—
Current portion of derivative liabilities	(22,987)	3,004	(19,983)
Long-term portion of derivative liabilities	(5,335)	3,915	(1,420)
Total derivative liabilities	$ (37,415)	$ 16,012	$ (21,403)
As of December 31, 2013			
Current portion of derivative assets	$ (773)	$ 773	$ —
Long-term portion of derivative assets	(4,062)	4,062	—
Current portion of derivative liabilities	(10,694)	4,341	(6,353)
Long-term portion of derivative liabilities	(189)	122	(67)
Total derivative liabilities	$ (15,718)	$ 9,298	$ (6,420)

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

In June 2013, the Partnership entered into contracts which provided the option to enter into swap contracts for future production periods (“swaptions”) up through September 30, 2013 for production volumes related to assets acquired from EP Energy (see Note 3). In connection with the swaption contracts, the Partnership paid premiums of $11.3 million, which represented their fair value on the date the transactions were initiated and were initially recorded as a derivative asset on the Partnership’s consolidated balance sheet. Swaption contract premiums paid are amortized over the period from initiation of the contract through their termination date. For the three months ended June 30, 2013, the Partnership recognized approximately $1.3 million of amortization expense in other, net on the Partnership’s consolidated statement of operations related to the swaption contracts.

The Partnership recognized losses of $9.2 million and gains of $2.3 million for the three months ended June 30, 2014 and 2013, respectively, and losses of $23.2 million and gains of $3.3 million for the six months ended June 30, 2014 and 2013, respectively, on settled contracts covering commodity production. These gains and losses were included within gas and oil production revenue in the Partnership’s consolidated statements of operations. As the underlying prices and terms in the Partnership’s derivative contracts were consistent with the indices used to sell its natural gas and oil, there were no gains or losses recognized during the three and six months ended June 30, 2014 and 2013, respectively, for hedge ineffectiveness or as a result of the discontinuance of any cash flow hedges.

At June 30, 2014, the Partnership had the following commodity derivatives:

Natural Gas – Fixed Price Swaps

Production Period Ending December 31,	Volumes (MMBtu)[1]	Average Fixed Price (per MMBtu)[1]	Fair Value Asset/ (Liability) (in thousands)[2]
2014	30,076,500	$ 4.152	$ (9,117)
2015	51,924,500	$ 4.239	882
2016	45,746,300	$ 4.311	3,003
2017	24,840,000	$ 4.532	3,321
2018	9,360,000	$ 4.619	360
			$ (1,551)

Natural Gas – Costless Collars

Production Period Ending December 31,	Option Type	Volumes	Average Floor and Cap	Fair Value Asset/ (Liability)

		(MMBtu)(1)	(per MMBtu)(1)	(in thousands)(2)
2014	Puts purchased	1,920,000	$ 4.221	$ 310
2014	Calls sold	1,920,000	$ 5.120	(198)
2015	Puts purchased	3,480,000	$ 4.234	1,487
2015	Calls sold	3,480,000	$ 5.129	(616)
				$ 983

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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)
2014	Puts purchased	900,000	$ 3.800	$ 27
2015	Puts purchased	1,440,000	$ 4.000	385
2016	Puts purchased	1,440,000	$ 4.150	582
				$ 994

Natural Gas – WAHA Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Liability (in thousands)(8)
2014	5,400,000	$ (0.110)	$ (306)
			$ (306)

Natural Gas – NGPL Basis Swaps

Production Period Ending December 31,	Volumes (MMBtu)(1)	Average Fixed Price (per MMBtu)(1)	Fair Value Liability (in thousands)(9)
2014	2,700,000	$ (0.110)	$ (22)
			$ (22)

Natural Gas Liquids – Natural Gasoline Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)(1)	Average Fixed Price (per Bbl)(1)	Fair Value Liability (in thousands)(3)
2015	96,000	$ 88.550	$ (787)
2016	84,000	$ 85.651	(479)
2017	60,000	$ 83.780	(306)
			$ (1,572)

Natural Gas Liquids – Ethane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Asset (in thousands)[4]
2014	1,260,000	$ 0.303	$ 18
			$ 18

Natural Gas Liquids – Propane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Liability (in thousands)[5]
2014	6,174,000	$ 0.999	$ (443)
2015	8,064,000	$ 1.016	(403)
			$ (846)

Natural Gas Liquids – Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Liability (in thousands)[6]
2014	756,000	$ 1.308	$ —
2015	1,512,000	$ 1.248	(58)
			$ (58)

Natural Gas Liquids – Iso Butane Fixed Price Swaps

Production Period Ending December 31,	Volumes (Gal)[1]	Average Fixed Price (per Gal)[1]	Fair Value Liability (in thousands)[7]
2014	756,000	$ 1.323	$ (16)
2015	1,512,000	$ 1.263	(69)
			$ (85)

Crude Oil – Fixed Price Swaps

Production Period Ending December 31,	Volumes (Bbl)[1]	Average Fixed Price (per Bbl)[1]	Fair Value Liability (in thousands)[3]
2014	591,000	$ 95.599	$ (4,471)
2015	1,095,000	$ 90.160	(7,207)
2016	777,000	$ 87.785	(2,802)
2017	132,000	$ 83.305	(734)
			$ (15,214)

Crude Oil – Costless Collar

Production Period Ending December 31,	Option Type	Volumes (Bbl)[1]	Average Floor and Cap (per Bbl)[1]	Fair Value Asset/ (Liability) (in thousands)[3]
2014	Puts purchased	20,580	$ 84.169	$ 5
2014	Calls sold	20,580	$ 113.308	(35)

2015	Puts purchased	29,250	$83.846		47
2015	Calls sold	29,250	$110.654		(91)
				$	(74)
			Total net liability	$	(17,733)

(1) “MMBtu” represents million British Thermal Units; “Bbl” represents barrels; “Gal” represents gallons.
(2) Fair value based on forward NYMEX natural gas prices, as applicable.
(3) Fair value based on forward WTI crude oil prices, as applicable.
(4) Fair value based on forward Mt. Belvieu ethane prices, as applicable.
(5) Fair value based on forward Mt. Belvieu propane prices, as applicable.
(6) Fair value based on forward Mt. Belvieu butane prices, as applicable.
(7) Fair value based on forward Mt. Belvieu iso butane prices, as applicable
(8) Fair value based on forward WAHA natural gas prices, as applicable
(9) Fair value based on forward NGPL natural gas prices, as applicable

At June 30, 2014, the Partnership had net cash proceeds of $1.3 million related to hedging positions monetized on behalf of the Drilling Partnerships’ limited partners, which were included within cash and cash equivalents on the Partnership’s consolidated balance sheet. The Partnership will allocate the monetization net proceeds to the Drilling Partnerships’ limited partners based on their natural gas and oil production generated over the period of the original derivative contracts.

In June 2012, the Partnership entered into natural gas put option contracts, which related to future natural gas production of the Drilling Partnerships. Therefore, a portion of any unrealized derivative gain or loss is allocable to the limited partners of the Drilling Partnerships based on their share of estimated gas production related to the derivatives not yet settled. At June 30, 2014, net unrealized derivative assets of $1.0 million were payable to the limited partners in the Drilling Partnerships related to these natural gas put option contracts.

At June 30, 2014, the Partnership had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under its revolving credit facility (see Note 7), the Partnership is required to utilize this secured hedge facility for future commodity risk management activity for its equity production volumes within the participating Drilling Partnerships. Each participating Drilling Partnership's obligations under the facility are secured by mortgages on its oil and gas properties and first priority security interests in substantially all of its assets and by a guarantee of the general partner of the Drilling Partnership. The Partnership, as general partner of the Drilling Partnerships, administers the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

NOTE 9 – FAIR VALUE OF FINANCIAL INSTRUMENTS

Management has established a hierarchy to measure the Partnership's financial instruments at fair value, which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. Observable inputs represent market data obtained from independent sources, whereas, unobservable inputs reflect the Partnership's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. The hierarchy defines three levels of inputs that may be used to measure fair value:

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

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

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

Assets and Liabilities Measured at Fair Value on a Recurring Basis

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

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Information for assets and liabilities measured at fair value at June 30, 2014 and December 31, 2013 was as follows (in thousands):

	Level 1	Level 2	Level 3	Total
As of June 30, 2014				
Derivative assets, gross				
Commodity swaps	$ —	$16,814	$ —	$16,814
Commodity basis swaps	—	25	—	25
Commodity puts	—	994	—	994
Commodity options	—	1,849	—	1,849
Total derivative assets, gross	—	19,682	—	19,682
Derivative liabilities, gross				
Commodity swaps	—	(36,123)	—	(36,123)
Commodity basis swaps	—	(352)	—	(352)
Commodity options	—	(940)	—	(940)
Total derivative liabilities, gross	—	(37,415)	—	(37,415)
Total derivatives, fair value, net	$ —	$(17,733)	$ —	$(17,733)

	Level 1	Level 2	Level 3	Total
As of December 31, 2013				
Derivative assets, gross				
Commodity swaps	$ —	$33,594	$ —	$33,594
Commodity puts	—	1,374	—	1,374
Commodity options	—	3,305	—	3,305
Total derivative assets, gross	—	38,273	—	38,273
Derivative liabilities, gross				
Commodity swaps	—	(14,624)	—	(14,624)
Commodity options	—	(1,094)	—	(1,094)
Total derivative liabilities, gross	—	(15,718)	—	(15,718)
Total derivatives, fair value, net	$ —	$22,555	$ —	$22,555

Other Financial Instruments

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

The Partnership's other current assets and liabilities on its consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair value of the Partnership's long-term debt at June 30, 2014 and December 31, 2013, which consists of its Senior Notes and outstanding borrowings under its revolving credit facility (see Note 7), were $1,244.3 million and $938.6 million, respectively, compared with the carrying amounts of $1,204.0 million and $942.3 million, respectively. At June 30, 2014 and December 31, 2013, the carrying values of outstanding borrowings under the Partnership's revolving credit facility (see Note 7), which bears interest at variable interest rates, approximated its estimated fair value. The estimated fair values of the Partnership's Senior Notes were based upon the market approach and calculated using yields of the Partnership as provided by financial institutions and thus were categorized as Level 3 values.

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

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

Information for assets and liabilities that were measured at fair value on a nonrecurring basis for the three and six months ended June 30, 2014 and 2013 were as follows (in thousands):

	Three Months Ended June 30,			
	2014		2013	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$7,326	$7,326	$599	$599
Total	$7,326	$7,326	$599	$599

	Six Months Ended June 30,			
	2014		2013	
	Level 3	Total	Level 3	Total
Asset retirement obligations	$7,855	$7,855	$1,244	$1,244
Total	$7,855	$7,855	$1,244	$1,244

Management estimates the fair value of the Partnership's long-lived assets in connection with reviewing these assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, using estimates, assumptions and judgments regarding such events or circumstances. For the year ended December 31, 2013, the Partnership recognized $38.0 million of impairment of long-lived assets which were defined as a Level 3 fair value measurements (see Note 2 – Impairment of Long-Lived Assets). No impairments were recognized during the three and six months ended June 30, 2014 and 2013.

During the three months ended June 30, 2014, the Partnership completed the Rangely Acquisition and the GeoMet acquisition (see Note 3). During the year ended December 31, 2013, the Partnership completed the acquisition of certain oil and gas assets from EP Energy (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 Rangely Acquisition and the GeoMet acquisition as of the respective acquisition dates, which are reflected in the Partnership's consolidated balance sheet as of June 30, 2014, are subject to change as the final valuations have 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.

The fair value of the warrants associated with the Class C preferred units (see Note 12) was measured using a Black-Scholes pricing model which is based on Level 3 inputs including a conversion price of $23.10, discount rate of 0.21% and estimated volatility rate of 35%.

NOTE 10 — CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with Drilling Partnerships. The Partnership conducts certain activities through, and a portion of its revenues are attributable to, the Drilling Partnerships. The Partnership serves as general partner and operator of the Drilling Partnerships and assumes customary rights and obligations for the Drilling Partnerships. As the general partner, the Partnership is liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the

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

Relationship with Atlas Pipeline Partners, L.P. The Partnership's general partner, ATLS, also maintains a general partner ownership interest in Atlas Pipeline Partners, L.P. ("APL"), a publicly traded Delaware master limited partnership (NYSE: APL) and midstream energy service provider engaged in the gathering, processing and treating of natural gas in the mid-continent and southwestern regions of the United States and gas gathering services in the Appalachian Basin in the northwest region of the United States. In the Chattanooga Shale, a portion of the natural gas produced by the Partnership is gathered and processed by APL. For both the three months ended June 30, 2014 and 2013, $0.1 million of gathering fees were paid by the Partnership to APL. For both the six months ended June 30, 2014 and 2013, $0.2 million of gathering fees were paid by the Partnership to APL.

NOTE 11 — COMMITMENTS AND CONTINGENCIES

General Commitments

The Partnership is the managing general partner of the Drilling Partnerships and has agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. Subject to certain conditions, investor partners in certain Drilling Partnerships have the right to present their interests for purchase by the Partnership, as managing general partner. The Partnership is not obligated to purchase more than 5% to 10% of the units in any calendar year. Based on its historical experience, as of June 30, 2014, the management of the Partnership believes that any such liability incurred would not be material. Also, the Partnership has agreed to subordinate a portion of its share of net partnership revenues from certain of the Drilling Partnerships to the benefit of the investor partners until they have received specified returns, typically 10% to 12% per year determined on a cumulative basis, over a specific period, typically the first five to eight years, in accordance with the terms of the partnership agreements. For the three months ended June 30, 2014 and 2013, $0.4 million and $2.1 million, respectively, and $3.8 million and $4.3 million for the six months ended June 30, 2014 and 2013, respectively, of the Partnership's revenues, net of corresponding production costs, were subordinated, which reduced its cash distributions received from the Drilling Partnerships.

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

In connection with the EP Energy 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 June 30, 2014 were as follows: 2014 - $4.4 million; 2015 $8.6 million; 2016 $2.1 million; and 2017 to 2018   none.

As of June 30, 2014, the Partnership is committed to expend approximately $36.4 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 May 2014, in connection with the closing of 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 $297.5 million. The units were registered under the Securities Act of 1933, as amended (the "Securities Act"), pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

In March 2014, 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 $129.1 million. The units were registered under the Securities Act, pursuant to a shelf registration statement on Form S-3, which was automatically effective on the filing date of February 3, 2014.

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

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

In June 2013, in connection with entering the EP Energy Acquisition (see Note 3), the Partnership sold an aggregate of 14,950,000 of its common limited partner units (including 1,950,000 units pursuant to an over-allotment option) in a public offering at a price of $21.75 per unit, yielding net proceeds of approximately $313.1 million. The Partnership utilized the net proceeds from the sale to repay the outstanding balance under its revolving credit facility (see Note 7).

In May 2013, the Partnership entered into an equity distribution agreement with Deutsche Bank Securities Inc., as representative of several banks. Pursuant to the equity distribution agreement, the Partnership could sell, from time to time through the agents, common units having an aggregate offering price of up to $25.0 million. During the year ended December 31, 2013, the Partnership issued 309,174 common limited partner units under the equity distribution program for net proceeds of $6.9 million, net of $0.4 million in commissions and other offering costs paid. The Partnership utilized the net proceeds from the sale to repay borrowings outstanding under its revolving credit facility. The Partnership terminated the equity distribution agreement effective December 27, 2013.

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 beginning for the month of January 2014, whereby it would distribute 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.

Distributions declared by the Partnership for the period from January 1, 2013 through June 30, 2014 were as follows (in thousands, except per unit amounts):

Date Cash Distribution Paid	For Quarter/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
May 15, 2013	March 31, 2013	$ 0.5100	$ 22,428	$ 1,957	$ 946
August 14, 2013	June 30, 2013	$ 0.5400	$ 32,097	$ 2,072	$ 1,884
November 14, 2013	September 30, 2013	$ 0.5600	$ 33,291	$ 4,248	$ 2,443
February 14, 2014	December 31, 2013	$ 0.5800	$ 34,489	$ 4,400	$ 2,891
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

On July 24, 2014, the Partnership declared a monthly distribution of $0.1966 per common unit for the month of June 2014. The $18.9 million distribution, including $1.4 million and $1.5 million to the general partner and preferred limited partners, respectively, will be paid on August 14, 2014 to holders of record as of August 6, 2014.

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 as well as employees of the general partner and its affiliates, consultants and joint venture partners (collectively, the "Participants"), who perform services for the Partnership. The 2012 LTIP is administered by the board of the general partner, a committee of the board or the board (or committee of the board) of an affiliate (the "LTIP Committee"). Under the 2012 LTIP, the LTIP Committee may grant awards of phantom units, restricted units or unit options for an aggregate of 2,900,000 common limited partner units. At June 30, 2014, the Partnership had 2,368,257 phantom units, restricted units and restricted options outstanding under the 2012 LTIP with 158,063 phantom units, restricted units and unit options available for grant.

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. Phantom units are subject to terms and conditions determined by the LTIP Committee, which may include vesting restrictions. In tandem with phantom unit grants, the LTIP Committee may grant distribution equivalent rights ("DERs"), which are the right to receive an amount in cash, securities, or other property equal to, and at the same time as, the cash distributions or other distributions of securities or other property made by the Partnership with respect to a common unit during the period that the underlying phantom unit is outstanding. Phantom units granted under the 2012 LTIP generally will vest 25% of the original granted amount on each of the four anniversaries of the date of grant. Of the phantom units outstanding under the 2012 LTIP at June 30, 2014, 329,925 units will vest within the following twelve months. All phantom units outstanding under the 2012 LTIP at June 30, 2014 include DERs. During the three months ended June 30, 2014 and 2013, the Partnership paid $0.4 million and $0.5 million, respectively, with respect to the 2012 LTIP's DERs. During the six months ended June 30, 2014 and 2013, the Partnership paid $1.1 million and $1.0

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 June 30,			
	2014		2013	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of period	812,308	$ 24.35	1,025,261	$ 24.53
Granted	223,523	20.29	8,540	24.09
Vested and issued[(1)]	(131,374)	24.69	(168,994)	24.69
Forfeited	(3,250)	24.80	(18,875)	24.03
Outstanding, end of period[(2)(3)]	901,207	$ 23.29	845,932	$ 24.51
Vested and not yet issued[(4)]	67,975	$ 24.66	32,750	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 1,590		$ 2,231

	Six Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Grant Date Fair Value	Number of Units	Weighted Average Grant Date Fair Value
Outstanding, beginning of year	839,808	$ 24.31	948,476	$ 24.76
Granted	227,023	20.30	91,790	22.15
Vested and issued[(1)]	(146,874)	24.48	(171,459)	24.69
Forfeited	(18,750)	23.00	(22,875)	24.23
Outstanding, end of period[(2)(3)]	901,207	$ 23.29	845,932	$ 24.51
Vested and not yet issued[(4)]	74,850	$ 24.49	32,750	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 3,321		$ 5,284

(1) The intrinsic value of phantom unit awards vested and issued during the three months ended June 30, 2014 and 2013 was $2.5 million and $4.1 million, respectively, and $2.9 million and $4.2 million during the six months ended June 30, 2014 and 2013, respectively.

(2) The aggregate intrinsic value for phantom unit awards outstanding at June 30, 2014 was $18.3 million.

(3) There was $0.1 million recognized as liabilities on the Partnership's consolidated balance sheets at the periods ended June 30, 2014 and December 31, 2013, representing 25,432 and 16,084 units, respectively, for the periods ending June 30, 2014 and December 31, 2013, 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 $21.38 and $22.15 for the periods ending June 30, 2014 and December 31, 2013, respectively.

(4) The intrinsic values of phantom unit awards vested, but not yet issued at June 30, 2014 and 2013 were $1.3 million and $0.8 million, respectively, and $1.5 million and $0.8 million during the six months ended June 30, 2014 and 2013, respectively.

At June 30, 2014, the Partnership had approximately $9.8 million in unrecognized compensation expense related to unvested phantom units outstanding under the 2012 LTIP based upon the fair value of the awards.

Unit Options

A unit option is the right to purchase a Partnership common unit in the future at a predetermined price (the exercise price). The exercise price of each option is determined by the LTIP Committee and may be equal to or greater than the fair market value of a common unit on the date the option is granted. The LTIP Committee will determine the vesting and exercise restrictions applicable to an award of options, if any, and the method by which the exercise price may be paid by the Participant. Unit option awards expire 10 years from the date of grant. Unit options granted under the 2012 LTIP generally will vest 25% on each of the next four anniversaries of the date of grant. There were 364,763 unit options outstanding under the 2012 LTIP at June 30, 2014 that will vest within the following twelve months. No cash was received from the exercise of options for the three and six months ended June 30, 2014 and 2013.

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

	Three Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of period	1,472,675	$ 24.66	1,513,500	$ 24.67
Granted	—	—	500	25.35
Exercised [1]	—	—	—	—
Forfeited	(5,625)	24.67	(19,250)	24.68
Outstanding, end of period[2][3]	1,467,050	$ 24.66	1,494,750	$ 24.67
Options exercisable, end of period[4]	734,400	$ 24.67	374,375	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 420		$ 771

	Six Months Ended June 30,			
	2014		2013	
	Number of Units	Weighted Average Exercise Price	Number of Units	Weighted Average Exercise Price
Outstanding, beginning of year	1,482,675	$ 24.66	1,515,500	$ 24.68
Granted	—	—	2,500	22.88
Exercised [1]	—	—	—	—
Forfeited	(15,625)	24.43	(23,250)	24.76
Outstanding, end of period[2][3]	1,467,050	$ 24.66	1,494,750	$ 24.67
Options exercisable, end of period[4]	734,400	$ 24.67	374,375	$ 24.67
Non-cash compensation expense recognized (in thousands)		$ 1,033		$ 1,965

(1) No options were exercised during the three and six months ended June 30, 2014 and 2013, respectively.
(2) The weighted average remaining contractual life for outstanding options at June 30, 2014 was 7.9 years.
(3) The aggregate intrinsic value of options outstanding at June 30, 2014 was approximately $100.
(4) The weighted average remaining contractual life for exercisable options at June 30, 2014 was 7.9 years. There were no intrinsic values for options exercisable at June 30, 2014 and 2013.

At June 30, 2014, the Partnership had approximately $1.7 million in unrecognized compensation expense related to unvested unit options outstanding under the 2012 LTIP based upon the fair value of the awards. The Partnership used the Black-Scholes option pricing model, which is based on Level 3 inputs, to estimate the weighted average fair value of options granted.

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

	Three Months Ended June 30,	Six Months Ended

			June 30,	
	2014	2013	2014	2013
Expected dividend yield	—%	7.3 %	—%	6.7 %
Expected unit price volatility	—%	44.0 %	—%	44.0%
Risk-free interest rate	—%	1.1 %	—%	1.1 %
Expected term (in years)	—	6.88	—	6.35
Fair value of unit options granted	$ —	$ 4.91	$—	$4.86

NOTE 15 – OPERATING SEGMENT INFORMATION

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Gas and oil production:				
Revenues	$104,057	$47,094	$200,302	$93,158
Operating costs and expenses	(41,763)	(19,035)	(78,555)	(34,251)
Depreciation, depletion and amortization expense	(55,531)	(20,580)	(103,560)	(40,276)
Segment income	$6,763	$7,479	$18,187	$18,631
Well construction and completion:				
Revenues	$16,336	$24,851	$65,713	$81,329
Operating costs and expenses	(14,206)	(21,609)	(57,142)	(70,721)
Segment income	$2,130	$3,242	$8,571	$10,608
Other partnership management:(1)				
Revenues	$14,324	$11,381	$26,047	$20,887
Operating costs and expenses	(6,699)	(7,264)	(13,594)	(13,995)
Depreciation, depletion and amortization expense	(2,470)	(1,617)	(4,678)	(3,129)
Segment income	$5,155	$2,500	$7,775	$3,763
Reconciliation of segment income to net loss:				
Segment income:				
Gas and oil production	$6,763	$7,479	$18,187	$18,631
Well construction and completion	2,130	3,242	8,571	10,608
Other partnership management	5,155	2,500	7,775	3,763
Total segment income	14,048	13,221	34,533	33,002
General and administrative expenses(2)	(21,315)	(14,217)	(37,770)	(31,784)
Interest expense(2)	(13,263)	(4,508)	(26,451)	(11,397)
Gain (loss) on asset sales and disposal(2)	9	(672)	(1,594)	(1,374)
Net loss	$(20,521)	$(6,176)	$(31,282)	$(11,553)
Capital expenditures:				
Gas and oil production	$48,809	$66,662	$83,792	$122,435
Other partnership management	4,200	3,133	7,540	4,045
Corporate and other	1,649	1,770	3,223	3,572
Total capital expenditures	$54,658	$71,565	$94,555	$130,052

	June 30, 2014	December 31, 2013
Balance sheet		
Goodwill:		
Gas and oil production	$18,145	$ 18,145
Well construction and completion	6,389	6,389
Other partnership management	7,250	7,250
	$31,784	$ 31,784
Total assets:		

Gas and oil production	$2,725,982	$ 2,170,712
Well construction and completion	23,561	55,031
Other partnership management	56,123	56,493
Corporate and other	75,620	61,564
	$2,881,286	$ 2,343,800

(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.

NOTE 16 — SUBSEQUENT EVENTS

Cash Distribution. On July 24, 2014, the Partnership declared a cash distribution of $0.1966 per common unit for the month of June 2014. The $18.9 million distribution, including $1.4 million and $1.5 million to the general partner and preferred limited partners, respectively, will be paid on August 14, 2014 to holders of record as of August 6, 2014.

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, 2013. These risks and uncertainties could cause actual results to differ materially from the results stated or implied in this document. Readers are cautioned not to place undue reliance on these forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly release the results of any revisions to forward-looking statements, which we may make to reflect events or circumstances after the date of this Form 10-Q or to reflect the occurrence of unanticipated events.

BUSINESS OVERVIEW

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

Atlas Energy, L.P. ("ATLS"), a publicly traded master-limited partnership (NYSE: ATLS), manages our operations and activities through its ownership of our general partner interest. At June 30, 2014, ATLS owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 27.7% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

FINANCIAL PRESENTATION