Atlas Resource Partners, L.P.
Form 10-Q
August 08, 2016

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, 2016

OR

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

For the transition period from to

Commission file number: 001-35317

ATLAS RESOURCE PARTNERS, L.P.

(Exact name of registrant as specified in its charter)

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

(Address of principal executive office) (Zip code)

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

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

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

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

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

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

The number of outstanding common limited partner units of the registrant on August 4, 2016 was 106,180,706.

ATLAS RESOURCE PARTNERS, L.P.

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ON FORM 10-Q

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Forward-Looking Statements

The matters discussed within this report include forward-looking statements. These statements may be identified by the use of forward-looking terminology such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “intend,” “m “might,” “plan,” “potential,” “predict,” “should,” or “will,” or the negative thereof or other variations thereon or comparable terminology. In particular, statements about our expectations, beliefs, plans, objectives, assumptions or future events or performance contained in this report are forward-looking statements. We have based these forward-looking statements on our current expectations, assumptions, estimates and projections. While we believe these expectations, assumptions, estimates and projections are reasonable, such forward-looking statements are only predictions and involve known and unknown risks and uncertainties, many of which are beyond our control. These and other important factors may cause our actual results, performance or achievements to differ materially from any future results, performance or achievements expressed or implied by these forward-looking statements. Some of the key factors that could cause actual results to differ from our expectations include:

- the potential adverse effects of the filings under Chapter 11 of the United States Bankruptcy Code (“Chapter 11”) and restructuring transactions on our operations, management and employees and the risks associated with operating our business during the restructuring process;
- the ability to consummate our pre-packaged plan of reorganization on the time frame or terms contemplated, or at all;
- the length of time that we will operate under Chapter 11 protection and the continued availability of operating capital during the pendency of the proceedings;
- risks and uncertainties associated with the Chapter 11 proceedings including our ability to achieve the anticipated benefits therefrom;
- risks associated with third party motions in the Chapter 11 proceedings, which may interfere with our ability to develop and consummate the Plan;
- the demand for natural gas, oil, NGLs and condensate;
- the price volatility of natural gas, oil, NGLs and condensate;
- changes in the differential between benchmark prices for oil and natural gas and wellhead prices that we receive;
- changes in the market price of our units;
- future financial and operating results;
- our ability to meet our liquidity needs;
- restrictive covenants in the debt documents governing our indebtedness that may adversely affect operational flexibility;
- actions that we may take in connection with our liquidity needs, including the ability to service our debt, and ability to satisfy covenants in our debt documents;
- economic conditions and instability in the financial markets;
- effects of debt payment obligations on our distributable cash;
- resource potential;
- the impact of our securities being quoted on the OTC Pink Sheets rather than listed on the New York Stock Exchange;
- effects of partial depletion or drainage by earlier offset drilling on our acreage;
- success in efficiently developing and exploiting our reserves and economically finding or acquiring additional recoverable reserves;
- the accuracy of estimated natural gas and oil reserves;
- the financial and accounting impact of hedging transactions;
- the ability to fulfill our substantial capital investment needs;
- expectations with regard to acquisition activity, or difficulties encountered in connection with acquisitions, dispositions or similar transactions;
-

the limited payment of distributions, or failure to declare a distribution, on outstanding common units or other equity securities;

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- any issuance of additional common units or other equity securities, and any resulting dilution or decline in the market price of any such securities;
- potential changes in tax laws which may impair the ability to obtain capital funds through investment partnerships;
- the ability to obtain adequate water to conduct drilling and production operations, and to dispose of the water used in and generated by these operations at a reasonable cost and within applicable environmental rules;
- the effects of unexpected operational events and drilling conditions, and other risks associated with drilling operations;
- impact fees and severance taxes;
- changes and potential changes in the regulatory and enforcement environment in the areas in which we conduct business;
- the effects of intense competition in the natural gas and oil industry;
- general market, labor and economic conditions and uncertainties;
- the ability to retain certain key customers;
- dependence on the gathering and transportation facilities of third parties;
- the availability of drilling rigs, equipment and crews;
- potential incurrence of significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations or an accidental release of hazardous substances into the environment;
- access to sufficient amounts of carbon dioxide for tertiary recovery operations;
- uncertainties with respect to the success of drilling wells at identified drilling locations;
- acquisitions may potentially prove to be worth less than we paid, or provide less than anticipated proved reserves;
- ability to identify all risks associated with the acquisition of oil and natural gas properties, or existing wells, and the sufficiency of indemnifications we receive from sellers to protect us from such risks;
- expirations of undeveloped leasehold acreage;
- uncertainty regarding leasing operating expenses, general and administrative expenses and funding and development costs;
- exposure to financial and other liabilities of the managing general partners of the investment partnerships;
- the ability to comply with, and the potential costs of compliance with, new and existing federal, state, local and other laws and regulations applicable to our business and operations;
- restrictions on hydraulic fracturing;
- exposure to new and existing litigation;
- development of alternative energy resources; and
- the effects of a cyber event or terrorist attack.

Other factors that could cause actual results to differ from those implied by the forward-looking statements in this report are more fully described under “Item 1A: Risk Factors” in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015. Given these risks and uncertainties, you are cautioned not to place undue reliance on these forward-looking statements. The forward-looking statements included in this report are made only as of the date hereof. We do not undertake and specifically decline any obligation to update any such statements or to publicly announce the results of any revisions to any of these statements to reflect future events or developments.

PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands)

(Unaudited)

	June 30, 2016	December 31, 2015
ASSETS		
Current assets:		
Cash and cash equivalents	$24,258	$1,353
Accounts receivable	62,555	63,367
Advances to affiliates	5,765	—
Current portion of derivative asset	99,654	159,460
Subscriptions receivable	—	19,877
Prepaid expenses and other	17,074	22,935
Current deferred financing costs	12,162	—
Total current assets	221,468	266,992
Property, plant and equipment, net	1,156,055	1,191,611
Goodwill and intangible assets, net	14,028	14,095
Long-term derivative asset	135,231	198,262
Other assets, net	13,604	28,989
Total assets	$1,540,386	$1,699,949
LIABILITIES AND PARTNERS’ CAPITAL (DEFICIT)		
Current liabilities:		
Accounts payable	$37,914	$49,249
Advances from affiliates	—	9,924
Liabilities associated with drilling contracts	—	21,483
Current portion of derivative payable to Drilling Partnerships	956	2,574
Accrued well drilling and completion costs	2,182	26,914
Accrued interest	24,085	25,436
Distribution payable	—	4,334
Accrued liabilities	17,144	22,086
Current portion of long-term debt	1,553,277	—
Total current liabilities	1,635,558	162,000
Long-term debt, less current portion, net	—	1,503,427
Asset retirement obligations	129,678	113,740

Other long-term liabilities	6,007	5,410
Commitments and contingencies (Note 9)		
Partners' Capital (Deficit):		
General partner's interest	(33,929)	(31,156)
Preferred limited partners' interests	188,462	188,739
Class C common limited partner warrants	1,176	1,176
Common limited partners' interests	(396,871)	(262,762)
Accumulated other comprehensive income	10,305	19,375
Total partners' deficit	(230,857)	(84,628)
Total liabilities and partners' deficit	$1,540,386	$1,699,949

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per unit data)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Revenues:				
Gas and oil production	$51,397	$97,260	$99,889	$201,509
Well construction and completion	(1,326)	16,956	774	40,611
Gathering and processing	1,600	2,177	3,095	4,361
Administration and oversight	495	547	950	1,806
Well services	4,190	6,102	8,622	12,726
Gain (loss) on mark-to-market derivatives	(73,264)	(26,944)	(27,144)	78,641
Other, net	84	27	198	60
Total revenues	(16,824)	96,125	86,384	339,714
Costs and expenses:				
Gas and oil production	30,852	43,135	66,694	88,633
Well construction and completion	(1,153)	14,745	673	35,315
Gathering and processing	2,191	2,516	4,470	4,933
Well services	1,474	2,139	3,652	4,337
General and administrative	23,761	13,287	40,838	30,422
Depreciation, depletion and amortization	29,008	42,494	59,053	85,485
Total costs and expenses	86,133	118,316	175,380	249,125
Operating income (loss)	(102,957)	(22,191)	(88,996)	90,589
Interest expense	(31,954)	(24,716)	(59,659)	(49,913)
Gain (loss) on asset sales and disposal	(502)	97	(493)	86
Gain on early extinguishment of debt	—	—	26,498	—
Other income (loss)	(6,156)	—	(6,156)	—
Net income (loss)	(141,569)	(46,810)	(128,806)	40,762
Preferred limited partner dividends	(365)	(4,234)	(4,013)	(7,887)
Net income (loss) attributable to common limited partners and the general partner	$(141,934)	$(51,044)	$(132,819)	$32,875

Allocation of net income (loss) attributable to common limited partners and the general partner:

Common limited partners' interest	$(139,096)	$(50,613)	$(130,163)	$29,731
General partner's interest	(2,838)	(431)	(2,656)	3,144
Net income (loss) attributable to common limited partners and the general partner	$(141,934)	$(51,044)	$(132,819)	$32,875
Net income (loss) attributable to common limited partners per unit (Note 2):				
Basic	$(1.36)	$(0.56)	$(1.27)	$0.34
Diluted	$(1.36)	$(0.56)	$(1.27)	$0.33
Weighted average common limited partner units outstanding (Note 2):				
Basic	102,430	90,516	102,416	88,036
Diluted	102,430	90,516	102,416	88,616

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in thousands)

(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$(141,569)	$(46,810)	$(128,806)	$40,762
Other comprehensive loss:				
Derivative instruments designated as cash flow hedges:				
Reclassification to net income (loss) of mark-to-market gains	(5,555)	(25,778)	(9,070)	(53,121)
Total other comprehensive loss	(5,555)	(25,778)	(9,070)	(53,121)
Comprehensive loss attributable to common and preferred limited partners and the general partner	$(147,124)	$(72,588)	$(137,876)	$(12,359)

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENT OF PARTNERS' CAPITAL (DEFICIT)

(in thousands, except unit data)

(Unaudited)

eral ners' Interest s A		Preferred Limited Partners' Interest Class C		Class D		Class E		Common Limited Partners' Interests		Class C Common Limited Partner Warrants		A O C
s	Amount	Units	Amount	Units	Amount	Units	Amount	Units	Amount	Warrants	Amount	In
61,445	$(31,156)	3,749,986	$85,402	4,090,328	$97,518	256,083	$5,819	102,160,866	$(262,762)	562,497	$1,176	$
08	—	—	—	—	—	—	—	245,175	204	—	—	-
	—	—	—	—	—	—	—	24,679	(298)	—	—	-
	39	—	637	—	2,205	—	172	—	1,277	—	—	-
	(156)	—	(2,550)	—	(4,410)	—	(344)	—	(5,118)	—	—	-
	—	—	—	—	—	—	—	—	(11)	—	—	-
	(2,656)	—	1,275	—	2,540	—	198	—	(130,163)	—	—	-
	—	—	—	—	—	—	—	—	—	—	—	(
66,953	$(33,929)	3,749,986	$84,764	4,090,328	$97,853	256,083	$5,845	102,430,720	$(396,871)	562,497	$1,176	$

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Six Months Ended June 30, 2016	2015
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income (loss)	$(128,806)	$40,762
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	59,053	85,485
(Gain) loss on derivatives	37,795	(71,808)
(Gain) loss on asset sales and disposal	493	(86)
Gain on extinguishment of debt	(26,498)	—
Other (income) loss	6,156	—
Non-cash compensation expense	(298)	4,209
Amortization of deferred financing costs and discount and premium on long-term debt	11,964	9,926
Changes in operating assets and liabilities:		
Accounts receivable, prepaid expenses and other	78,626	61,803
Accounts payable and accrued liabilities	(55,794)	(77,106)
Net cash provided by (used in) operating activities	(17,309)	53,185
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures	(18,820)	(69,491)
Net cash paid for acquisitions	—	(36,967)
Other	—	167
Net cash used in investing activities	(18,820)	(106,291)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Borrowings under revolving credit facility	135,000	231,000
Repayments under revolving credit facility	(57,500)	(377,000)
Borrowings under second lien term loan facility	—	242,500
Senior note repurchases	(5,528)	—
Distributions paid to unitholders	(12,578)	(83,596)
Net proceeds from issuance of common limited partner units	204	70,869
Net proceeds from issuance of preferred units	—	6,005
Arkoma transaction adjustment	—	(35,404)
Deferred financing costs, distribution equivalent rights and other	(564)	(15,908)
Net cash provided by financing activities	59,034	38,466
Net change in cash and cash equivalents	22,905	(14,640)
Cash and cash equivalents, beginning of year	1,353	15,247

Cash and cash equivalents, end of period	$24,258	$607

See accompanying notes to condensed consolidated financial statements.

ATLAS RESOURCE PARTNERS, L.P.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

NOTE 1 – BASIS OF PRESENTATION

We are a publicly traded (OTC: ARPJ) Delaware master-limited partnership ("MLP") and an independent developer and producer of natural gas, crude oil and natural gas liquids ("NGL") with operations in basins across the United States. We sponsor and manage tax-advantaged investment partnerships (the "Drilling Partnerships"), in which we coinvest, to finance a portion of our natural gas, crude oil and NGL production activities. Unless the context otherwise requires, references to "Atlas Resource Partners, L.P.," "Atlas Resource Partners," "the Partnership," "we," "us," "our" and "our compar refer to Atlas Resource Partners, L.P. and our consolidated subsidiaries.

Atlas Energy Group, LLC ("Atlas Energy Group" or "ATLS"; OTC: ATLS), our general partner, manages our operations and activities through its ownership interest. At June 30, 2016, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us, and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

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

At June 30, 2016, we had 102,430,720 common limited partner units issued and outstanding. The common units are a class of limited partner interests in us. The holders of common units are entitled to participate in partnership distributions, exercise the rights or privileges available to holders of common units and have limited liability as outlined in the partnership agreement.

The accompanying condensed consolidated financial statements, which are unaudited except that the balance sheet at December 31, 2015 was derived from audited financial statements, have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission and are presented in accordance with 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. It is suggested that these interim condensed consolidated financial statements be read in conjunction with the financial statements and the notes thereto included in our latest Annual Report on Form 10-K. In management's opinion, all adjustments necessary for a fair presentation of our financial position, results of operations and cash flows for the periods disclosed have been made. Certain amounts in the prior year's financial statements have been reclassified to conform to the current year presentation due to the adoption of certain accounting standards (see Notes 2 and 5). The results of operations for the interim periods presented may not necessarily be indicative of the results of operations for the full year.

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Principles of Consolidation

Our condensed consolidated financial statements include our accounts and the accounts of our wholly-owned subsidiaries. Transactions between us and other ATLS operations have been identified in the condensed 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, our condensed consolidated financial statements include our pro-rata share of assets, liabilities, income and lease operating and general and administrative costs and expenses of the Drilling Partnerships in which we have an interest. Such interests generally approximate 30%. Our condensed consolidated financial statements do not include proportional consolidation of the depletion or impairment expenses of the Drilling Partnerships. Rather, we calculate these items specific to our own economics.

Ability to Continue as a Going Concern

On July 25, 2016, we and certain of our subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the “Restructuring Support Agreement”) with (i) lenders holding 100% of our senior secured revolving credit facility (the “First Lien Lenders”), (ii) lenders holding 100% of our second lien term loan (the “Second Lien Lenders”) and (iii) holders (the “Consenting Noteholders” and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that become party to the Restructuring Support Agreement, the “Restructuring Support Parties”) of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the “7.75% Senior Notes”) and the 9.25% Senior Notes due 2021 (the “9.25% Senior Notes” and, together with the 7.75% Senior Notes, the “Notes”) of our subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the “Issuers”). Under the

Restructuring Support Agreement, the Restructuring Support Parties have agreed, subject to certain terms and conditions, to support our restructuring (the "Restructuring") pursuant to a pre-packaged plan of reorganization (the "Plan"). (See Note 3 for further information.)

On July 27, 2016, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code ("Chapter 11") in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court," and the cases commenced thereby, the "Chapter 11 Filings"). The cases commenced thereby are being jointly administered under the caption "In re: ATLAS RESOURCE PARTNERS, L.P., et al."

The Restructuring, including as a result of us monetizing certain hedges to pay down borrowings outstanding under our senior secured credit facility, will result in a reduction of our existing debt by approximately $900 million and elimination of approximately $80 million of our annual debt service obligations. Pursuant to the Plan, our business assets and operations will vest in a limited liability company, which will be classified as a corporation for U.S. federal income tax purposes ("New Holdco"). We expect to consummate the Plan and emerge from Chapter 11 before the end of the third quarter of 2016. Interested parties should refer to the information and the limitations and qualifications discussed in the disclosure statement related to the Restructuring (the "Disclosure Statement") which was filed as Exhibit 99.1 to our Current Report on Form 8-K filed with the Securities and Exchange Commission on July 25, 2016.

We intend to continue to operate our businesses as "debtors in possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, it is contemplated that all suppliers, vendors, employees, royalty owners, trade partners and landlords will be unimpaired by the Plan and will be satisfied in full in the ordinary course of business, and our existing trade contracts and terms will be maintained. To assure ordinary course operations, we obtained interim approval from the Bankruptcy Court on a variety of "first day" motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to us, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

The Chapter 11 Filings constituted an event of default that accelerated all of our outstanding debt obligations under the First Lien Credit Facility (as defined below), the Second Lien Term Loan (as defined below) and the indenture governing the Notes. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11. Accordingly, we classified all of the aforementioned outstanding debt obligations as a current liability on our condensed consolidated balance sheet as of June 30, 2016. (See Note 5, "Debt," for further information).

The significant risks and uncertainties related to our Chapter 11 Filings raise substantial doubt about our ability to continue as a going concern. The condensed consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The condensed consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported amounts of income and expenses could be required and could be material.

Arkoma Acquisition

On June 5, 2015, we acquired coal-bed methane producing natural gas assets in the Arkoma Basin in eastern Oklahoma from ATLS (the "Arkoma Acquisition") for $31.5 million, net of purchase price adjustments, which was funded through the issuance of 6,500,000 of our common limited partner units. We determined that the Arkoma

Acquisition constituted a transaction between entities under common control and, accordingly, retroactively adjusted our prior period condensed consolidated financial statements assuming our common limited partners participated in the net income (loss) of the Arkoma operations before the date of the transaction.

In April 2015, the Financial Accounting Standards Board ("FASB") updated the accounting guidance for earnings per unit ("EPU") of master limited partnerships ("MLP") applying the two-class method. The updated accounting guidance specifies that for general partner transfers (or "drop downs") to an MLP accounted for as a transaction between entities under common control, the earnings (losses) of the transferred business before the date of the transaction should be allocated entirely to the general partner's interest, and previously reported EPU of the limited partners should not change. Qualitative disclosures about how the rights to the earnings (losses) differ before and after the drop down transaction occurs are also required.

We adopted this accounting guidance upon its effective date of January 1, 2016, which resulted in the following retrospective restatement to allocate the net income (loss) of the Arkoma operations before the date of the transaction entirely to our general partner's interest:

Condensed Consolidated Statement of Operations	Previously Filed	Adjustment	Restated
Three Months Ended June 30, 2015:			

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Common limited partners' interest	$(50,023)	$(590)	$(50,613)
General partner's interest	$(1,021)	$590	$(431)
Net loss attributable to common limited partners per unit – basic	$(0.55)	$(0.01)	$(0.56)
Net loss attributable to common limited partners per unit – diluted	$(0.55)	$(0.01)	$(0.56)
Six Months Ended June 30, 2015:			
Common limited partners' interest	$32,217	$(2,486)	$29,731
General partner's interest	$658	$2,486	$3,144
Net income attributable to common limited partners per unit – basic	$0.36	$(0.02)	$0.34
Net income attributable to common limited partners per unit – diluted	$0.36	$(0.03)	$0.33
Condensed Consolidated Balance Sheet			
December 31, 2015:			
Common limited partners' interest	$(260,276)	$(2,486)	$(262,762)
General partners' interest	$(33,642)	$2,486	$(31,156)

Prior to the Arkoma Acquisition, our common limited partners did not participate in the net income (loss) of the Arkoma operations. Subsequent to the Arkoma Acquisition, our common limited partners participate in the net income (loss) of the Arkoma operations, which is determined after the deduction of the general partner's and the preferred unitholders' interests.

Use of Estimates

The preparation of our condensed 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 our condensed consolidated financial statements, as well as the reported amounts of revenue and costs and expenses during the reporting periods. Our condensed consolidated financial statements are based on a number of significant estimates, including revenue and expense accruals, depletion, depreciation and amortization, fair value of derivative instruments and fair value of certain gas and oil properties and asset retirement obligations. The oil and 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. Actual results could differ from those estimates.

Net Income Per Common Unit

Basic net income attributable to common limited partners per unit is computed by dividing net income 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 attributable to common limited partners is determined by deducting net income attributable to participating securities, if applicable, income attributable to preferred limited partners and net income attributable to the general partner's Class A units. The general partner's interest in net income is calculated on a quarterly basis based upon its Class A units and incentive distributions to be distributed for the quarter (see Note 10), 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 allocated with respect to the general partner's and limited partners' ownership interests.

We present net income 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. 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, our management believes the partnership agreement contractually limits cash distributions to available cash; therefore, undistributed earnings are not allocated to the incentive distribution rights.

Unvested unit-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 our long-term incentive plan, contain non-forfeitable rights to distribution equivalents. The participation rights would result in a non-contingent transfer of value each time we declare 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 per unit must be after the allocation of only net income to the phantom units on a pro-rata basis.

The following is a reconciliation of net income allocated to the common limited partners for purposes of calculating net income attributable to common limited partners per unit (in thousands, except unit data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Net income (loss)	$(141,569)	$(46,810)	$(128,806)	40,762
Preferred limited partner dividends	(365)	(4,234)	(4,013)	(7,887)
Net income (loss) attributable to common limited partners and the general partner	(141,934)	(51,044)	(132,819)	32,875
Less: General partner's interest	(2,838)	(431)	(2,656)	3,144
Net income attributable to common limited partners	(139,096)	(50,613)	(130,163)	29,731
Less: Net income attributable to participating securities – phantom units	—	—	—	194
Net income (loss) utilized in the calculation of net income (loss) attributable to common limited partners per unit - Basic	(139,096)	(50,613)	(130,163)	29,537
Plus: Convertible preferred limited partner dividends(1)	—	—	—	—
Net income (loss) utilized in the calculation of net income attributable to common limited partners per unit - Diluted	$(139,096)	$(50,613)	$(130,163)	$29,537

(1) For the three and six months ended June 30, 2016 and 2015, distributions on our Class C convertible preferred units were excluded, because the inclusion of such preferred distributions would have been anti-dilutive.

Diluted net income attributable to common limited partners per unit is calculated by dividing net income attributable to common limited partners, less income allocable to participating securities, by the sum of the weighted average number of common limited partner units outstanding and the dilutive effect of unit option awards, convertible preferred units and warrants, as calculated by the treasury stock or if converted methods, as applicable. Unit options consist of common units issuable upon payment of an exercise price by the participant under the terms of our long-term incentive plan.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Weighted average number of common limited partner units—basic	102,430	90,516	102,416	88,036
Add effect of dilutive incentive awards(1)	—	—	—	580
Add effect of dilutive convertible preferred limited partner units(2)	—	—	—	—
Weighted average number of common limited partner units—diluted	102,430	90,516	102,416	88,616

(1) For the three and six months ended June 30, 2016, approximately 274,000 and 283,000 phantom units, respectively, were excluded from the computation of diluted earnings attributable to common limited partners per unit because the inclusion of such units would have been anti-dilutive. For the three months ended June 30, 2015,approximately 470,000 phantom 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.

(2) For the three and six months ended June 30, 2016 and 2015, potential common limited partner units issuable upon (a) conversion of our Class C preferred units and (b) exercise of the common unit warrants issued with the Class C preferred units were excluded from the computation of diluted earnings attributable to common limited partners per unit, because the inclusion of such units would have been anti-dilutive. As the Class D and Class E preferred units are convertible only upon a change of control event, they are not considered dilutive securities for earnings per unit purposes.

Recently Issued Accounting Standards

In February 2016, the FASB updated the accounting guidance related to leases. The updated accounting guidance requires lessees to recognize a lease asset and liability at the commencement date of all leases (with the exception of short-term leases), initially measured at the present value of the lease payments. The updated guidance is effective for us as of January 1, 2019 and requires a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest period presented. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements.

In August 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs specific to line of credit arrangements. The updated accounting guidance allows the option of presenting deferred debt issuance costs related to line-of-credit arrangements as an asset, and subsequently amortizing over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings. We adopted the updated accounting guidance effective January 1, 2016, and it did not have a material impact on our condensed consolidated financial statements.

In February 2015, the FASB updated the accounting guidance related to consolidation under the variable interest entity and voting interest entity models. The updated accounting guidance modifies the consolidation guidance for variable interest entities, limited partnerships and similar legal entities. We adopted this accounting guidance upon its effective date of January 1, 2016, and it did not have a material impact on our condensed consolidated financial statements.

In August 2014, the FASB updated the accounting guidance related to the evaluation of whether there is substantial doubt about an entity's ability to continue as a going concern. The updated accounting guidance requires an entity's management to evaluate whether there are conditions or events that raise substantial doubt about its ability to continue as a going concern within one year from the date the financial statements are issued and provide footnote disclosures, if necessary. We adopted this accounting guidance on January 1, 2016, and provided enhanced disclosures, as applicable, within our condensed consolidated financial statements.

In May 2014, the FASB updated the accounting guidance related to revenue recognition. The updated accounting guidance provides a single, contract-based revenue recognition model to help improve financial reporting by providing clearer guidance on when an entity should recognize revenue, and by reducing the number of standards to which an entity has to refer. In July 2015, the FASB voted to defer the effective date by one year to December 15, 2017 for annual reporting periods beginning after that date. The updated accounting guidance provides companies with alternative methods of adoption. We are currently in the process of determining the impact that the updated accounting guidance will have on our condensed consolidated financial statements and our method of adoption.

NOTE 3 – RESTRUCTURING SUPPORT AGREEMENT

As disclosed in Note 2, on July 25, 2016, we and certain of our subsidiaries and ATLS, solely with respect to certain sections thereof, entered into the Restructuring Support Agreement with the Restructuring Support Parties. On July 27, 2016, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. Under the Restructuring Support Agreement, the Restructuring Support Parties have agreed, subject to certain terms and conditions, to support our Restructuring pursuant to the Plan.

In particular, under the Plan, on the Plan's effective date (the "Plan Effective Date"), the First Lien Lenders will receive cash payment of all obligations owed to them by us pursuant to the senior secured revolving credit facility (other than $440 million of principal and face amount of letters of credit) and become lenders under an exit facility credit agreement (the "First Lien Exit Facility"), composed of a $410 million conforming reserve-based tranche and a $30 million non-conforming tranche. The non-conforming tranche will mature on May 1, 2017 and the conforming reserve-based tranche will mature on August 23, 2019. In addition, we will enter into a new second lien credit agreement (the "Second Lien Exit Facility" and, together with the First Lien Exit Facility, the "Exit Facilities"). The Second Lien Lenders will receive a pro rata share of the Second Lien Exit Facility, which will have an aggregate principal amount of $250 million plus the amounts resulting from the accrual of paid in kind interest on the principal amount of $250 million from the commencement of the Chapter 11 Filings, with interest expense paid in cash to be reduced to 2% and the remainder to be paid-in-kind from the commencement date through May 1, 2017 at a rate equal to Adjusted LIBO Rate plus 9% per annum. During the next 15-month period, cash and in-kind interest will vary based on a pricing grid tied to our leverage ratio under the revolving credit facility. After such 15-month period, interest will accrue at a rate equal to Adjusted LIBO Rate plus 9% per annum and will be payable in cash. In addition to the Second Lien Exit Facility, the Second Lien Lenders will receive a pro rata share of 10% of the common equity interests of New HoldCo, subject to dilution by a management incentive plan. Holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the chapter 11 cases, will receive, on the Plan Effective Date, 90% of the common equity interests of New HoldCo as of the Plan Effective Date, subject to dilution by a management incentive plan.

Under the Plan, holders of our limited partnership units will receive no recovery. On the Plan Effective Date, all of our preferred limited partnership units and common limited partnership units will be cancelled without the receipt of any consideration.

We intend to continue to operate our businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords will be unimpaired by the Plan and will be satisfied in full in the ordinary course of business, and our existing trade contracts and terms will be maintained. To assure ordinary course operations, we obtained interim approval from the Bankruptcy Court of a variety on “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to us, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

Under the Plan, on the Plan Effective Date, a wholly owned subsidiary of ATLS (“ARP Mgt LLC”) will receive a preferred share of New HoldCo. The preferred share will entitle ARP Mgt LLC to receive 2% of the economics of New HoldCo (subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to the management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors of New HoldCo are representatives of ARP Mgt LLC (the “New HoldCo Class A Directors”). For so long as ARP Mgt LLC holds such preferred share, the New HoldCo Class A Directors will be appointed by a majority of the Class A Directors then in office. New HoldCo will have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in New HoldCo's limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of New HoldCo unaffiliated with ARP Mgt LLC voting in favor of the exercise of the right to purchase the preferred share.

In accordance with, and subject to the terms and conditions of, the Restructuring Support Agreement, each of the Restructuring Support Parties has agreed, among other things, to: (i) support and take all commercially reasonable actions necessary or reasonably requested by us to facilitate consummation of the Restructuring in accordance with the Plan and the related term sheets, including without limitation, if applicable, to timely vote to accept the Plan; (ii) use commercially reasonable efforts to support the confirmation of the Plan and approval of the Disclosure Statement and the solicitation procedures; (iii) not object to, delay, interfere, impede, or take any other action to delay, interfere or impede, directly or indirectly, with the Restructuring, confirmation of the Plan, or approval of the Disclosure Statement or the solicitation procedures; and (iv) not object to our efforts to enter into the Exit Facilities, and not object to, or support the efforts of any other person to oppose or object to, the Exit Facilities.

In accordance with, and subject to the terms and conditions of, the Restructuring Support Agreement, we have agreed, subject to applicable fiduciary duties, among other things, to: (i) support and complete the Restructuring and all transactions set forth in the Plan and the Restructuring Support Agreement; (ii) complete the Restructuring and all transactions set forth or described in the Plan; (iii) take any and all necessary actions in furtherance of the Restructuring, the Restructuring Support Agreement and the Plan; (iv) make commercially reasonable efforts to obtain any and all required regulatory and/or third-party approvals for the Restructuring; and (v) operate the business in the ordinary course, taking into account the Restructuring.

The Restructuring Support Agreement may be terminated upon the occurrence of certain events, including the failure to meet specified milestones related to filing, confirmation and consummation of the Plan, among other requirements, and in the event of certain breaches by the parties under the Restructuring Support Agreement. There can be no assurance that the restructuring transactions will be consummated.

NOTE 4 – PROPERTY, PLANT AND EQUIPMENT

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

	June 30, 2016	December 31, 2015	Estimated Useful Lives in Years
Natural gas and oil properties:			
Proved properties:			
Leasehold interests	$505,763	$503,586	
Pre-development costs	6,442	6,014	
Wells and related equipment	3,092,417	3,076,239	
Total proved properties	3,604,622	3,585,839	
Unproved properties	213,047	213,047	
Support equipment	44,264	44,921	
Total natural gas and oil properties	3,861,933	3,843,807	
Pipelines, processing and compression facilities	58,066	56,738	15 – 20
Rights of way	829	829	20 – 40
Land, buildings and improvements	9,798	9,798	3 – 40
Other	18,422	18,405	3 – 10
	3,949,048	3,929,577	
Less – accumulated depreciation, depletion and amortization	(2,792,993)	(2,737,966)	
	$1,156,055	$1,191,611	

During the six months ended June 30, 2016 and 2015, we recognized $18.7 million and $28.1 million, respectively, of non-cash property, plant and equipment additions, which were included within the changes in accounts payable and accrued liabilities on our condensed consolidated statements of cash flows.

We capitalize 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 us was 6.6% for both the three months ended June 30, 2016 and 2015. The weighted average interest rate used to capitalize interest on borrowed funds by us was 6.7% and 6.4% for the six months ended June 30, 2016 and 2015, respectively. The aggregate amount of interest capitalized by us was $2.4 million and $4.1 million for the three months ended June 30, 2016 and 2015, respectively. The aggregate amount of interest capitalized by us was $4.8 million and $8.0 million for the six months ended June 30, 2016 and 2015, respectively.

For the three months ended June 30, 2016 and 2015, we recorded $1.7 million and $1.6 million, respectively, of accretion expense related to our asset retirement obligations within depreciation, depletion and amortization in our condensed consolidated statements of operations. For the six months ended June 30, 2016 and 2015, we recorded $3.3 million and $3.2 million, respectively, of accretion expense related to our asset retirement obligations within depreciation, depletion and amortization in our condensed consolidated statements of operations. For the three months ended June 30, 2016 and 2015, we recorded liabilities of $9.9 million and $0.2 million, respectively, in asset retirement obligations in our condensed consolidated balance sheet due to the liquidation of some of our Drilling Partnerships. For the six months ended June 30, 2016 and 2015, we recorded liabilities of $12.9 million and $0.5 million, respectively, in asset retirement obligations in our condensed consolidated balance sheet due to the liquidation of some of our Drilling Partnerships.

NOTE 5 – DEBT

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

	June 30, 2016	December 31, 2015
First Lien Credit Facility	$669,500	$592,000
Second Lien Term Loan	244,534	243,783
7.75 % Senior Notes – due 2021	354,385	374,619
9.25 % Senior Notes – due 2021	312,096	324,080
Deferred financing costs	(27,238)	(31,055)
Total debt, net	1,553,277	1,503,427
Less current maturities	(1,553,277)	—
Total long-term debt, net	$—	$1,503,427

In April 2015, the FASB updated the accounting guidance related to the balance sheet presentation of debt issuance costs. The updated accounting guidance requires that debt issuance costs be presented as a direct deduction from the associated debt obligation. We adopted this accounting guidance upon its effective date of January 1, 2016. The retrospective effect of the reclassification resulted in the following changes:

Condensed Consolidated Balance Sheet	Previously Filed	Adjustment	Restated
December 31, 2015:			
Other assets, net	$60,044	$ (31,055)	$28,989
Long-term debt, net	$1,534,482	$ (31,055)	$1,503,427

Cash Interest. Total cash payments for interest by us were $12.5 million and $53.7 million for the three and six months ended June 30, 2016, respectively, and $10.6 million and $47.3 million for the three and six months ended June 30, 2015, respectively.

First Lien Credit Facility

We are a party to a Second Amended and Restated Credit Agreement, dated as of July 31, 2013 by and among us, the lenders from time to time party thereto, and Wells Fargo Bank, National Association, as administrative agent, as amended, supplemented or modified from time to time (the "First Lien Credit Facility"), which provides for a senior secured revolving credit facility with a maximum borrowing base of $1.5 billion scheduled to mature in July 2018.

On June 8, 2016, we received notice from Wells Fargo Bank, National Association, as administrative agent under our First Lien Credit Facility that our borrowing base had been redetermined in accordance with the First Lien Credit Facility and reduced from $700.0 million to $530.0 million. As of June 30, 2016, $669.5 million in borrowings were outstanding (which includes $4.2 million in letters of credit) under the First Lien Credit Facility, resulting in a borrowing base deficiency of $143.7 million. Our First Lien Credit Facility provides that within 30 days after our receipt of a notification of a borrowing base deficiency, we must elect to cure the borrowing base deficiency through any combination of the following actions: (i) repay amounts outstanding under the First Lien Credit Facility sufficient to cure the borrowing base deficiency, either within 30 days after receipt of the borrowing base deficiency notice or in four equal monthly installments beginning on July 11, 2016; or (ii) pledge as collateral additional oil and gas properties acceptable to the administrative agent and lenders sufficient to cure the borrowing base deficiency within 60 days after receipt of the borrowing base deficiency notice. As part of the discussions with our lenders and noteholders (see Notes 1 and 3), we determined not to make the first installment payment that was due on July 11, 2016.

In connection therewith and in support of negotiations with our lenders and noteholders, on July 11, 2016, we and certain of our subsidiaries entered into two forbearance agreements: (i) with Wells Fargo Bank, National Association, as administrative agent, and the other lenders under the First Lien Credit Facility (the “First Lien Credit Forbearance”) and (ii) with the Consenting Noteholders of our 7.75% Senior Notes and 9.25% Senior Notes (the “Notes Forbearance”).

Pursuant to the First Lien Credit Forbearance, the administrative agent and the lenders representing approximately 81% of the outstanding indebtedness under the First Lien Credit Facility agreed to forbear from exercising their rights and remedies arising from non-payment of the first installment of the borrowing base deficiency cure due on July 11, 2016 and related cross-defaults (the “Specified Default”) until the earliest to occur of (i) July 27, 2016, (ii) the occurrence of an event of default under the First Lien Credit Facility (unrelated to the Specified Default) or (iii) the exercise by any holder of indebtedness outstanding under the Second Lien Term Loan, the Notes or any other material indebtedness of ours of rights or remedies against us or the other loan parties or their respective property.

Pursuant to the Notes Forbearance, the holders of approximately 78% of the aggregate outstanding principal amount of the 7.75% Senior Notes and approximately 82% of the 9.25% Senior Notes agreed to forbear from exercising their rights and remedies arising from the cross-default that resulted from the Specified Default until the earliest to occur of (i) July 27, 2016, (ii) another event of default under the 7.75% Senior Notes indenture or the 9.25% Senior Notes indenture or (iii) any other holder of the Notes commences a legal proceeding against us or the other loan parties or their respective property. The holders of a majority of the Second Lien Term Loan were supportive of the forbearance.

Our borrowing base is scheduled for semi-annual redeterminations in May and November of each year. Up to $20.0 million of the First Lien Credit Facility may be in the form of standby letters of credit, of which $4.2 million was outstanding at June 30, 2016. Our obligations under the First Lien Credit Facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, obligations under the First Lien Credit Facility are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor. At June 30, 2016, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 4.0%.

The First Lien Credit Facility contains customary covenants including, without limitation, covenants that limit our ability to incur additional indebtedness (but which permits second lien debt in an aggregate principal amount of up to $300.0 million and third lien debt that satisfies certain conditions including pro forma financial covenants), grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidate with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. The First Lien Credit Facility also requires us to maintain a ratio of First Lien Debt to EBITDA (ratio as defined in the First Lien Credit Facility agreement) of not greater than 2.75 to 1.00, and a ratio of current assets to current liabilities (ratio as defined in the First Lien Credit Facility agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. We were not in compliance with these covenants as of June 30, 2016.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the First Lien Credit Facility and as a result, we classified $669.5 million of our outstanding amounts under the First Lien Credit Facility as current portion of long-term debt and $12.2 million of deferred financing costs related to the First Lien Credit Facility as current assets within our condensed consolidated balance sheet as of June 30, 2016. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11.

Pursuant to the Restructuring Support Agreement, we completed the sale of substantially all our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the First Lien Credit Facility. Accordingly, approximately $440 million remained outstanding under the First Lien Credit Facility as of July 27, 2016, the date of the Chapter 11 Filings.

On the Plan Effective Date, we expect to enter into the new First Lien Exit Facility, which will replace the First Lien Credit Facility (see Note 3).

Second Lien Term Loan

We are party to a Second Lien Credit Agreement, dated as of February 23, 2015 by and among us, the lenders from time to time party thereto, and Wilmington Trust, National Association, as administrative agent, as amended, supplemented or modified from time to time (the "Second Lien Term Loan"), which provides for a second lien term loan in an original principal amount of $250.0 million. The Second Lien Term Loan matures on February 23, 2020. The Second Lien Term Loan is presented in the table above net of unamortized discount of $5.5 million as of June 30, 2016.

Our obligations under the Second Lien Term Loan are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing First Lien Credit Facility. In addition, the obligations under the Second Lien Term Loan are guaranteed by our material restricted subsidiaries. At June 30, 2016, the weighted average interest rate on outstanding borrowings under the Second Lien Term Loan was 10.0%.

The Second Lien Term Loan contains customary covenants including, without limitation, covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred units, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Term Loan contains covenants substantially similar to those in the First Lien Credit Facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. We were not in compliance with the financial covenants as of June 30, 2016.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the Second Lien Term Loan and as a result, we classified $244.5 million of our outstanding amounts under the Second Lien Term Loan, which is net of $5.5 million unamortized discount and $9.4 million deferred financing costs, as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11.

On the Plan Effective Date, we expect to enter into the new Second Lien Exit Facility, which will replace the Second Lien Term Loan (see Note 3).

Senior Notes

At June 30, 2016, we had $354.4 million outstanding of our 7.75% Senior Notes due 2021. The 7.75% Senior Notes were presented net of a $0.3 million unamortized discount as of June 30, 2016.

At June 30, 2016, we had $312.1 million outstanding of our 9.25% Senior Notes due 2021. The 9.25% Senior Notes were presented net of a $0.8 million unamortized discount as of June 30, 2016.

In January and February 2016, we executed transactions to repurchase $20.3 million of our 7.75% Senior Notes and $12.1 million of our 9.25% Senior Notes for $5.5 million, which includes $0.6 million of interest. As a result of these transactions, we recognized $26.5 million as gain on early extinguishment of debt, net of accelerated amortization of deferred financing costs of $0.9 million, in our condensed consolidated statement of operations for the six months ended June 30, 2016.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, subject to certain customary automatic release provisions, including, in certain circumstances, the sale or other disposition of all or substantially all the assets of, or all of the equity interests in, the subsidiary guarantor, or the subsidiary guarantor is declared "unrestricted" for covenant purposes, and any subsidiaries of ours, other than the subsidiary guarantors, are minor. There are no restrictions on our ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants including, without limitation, covenants that limit our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We were in compliance with these covenants as of June 30, 2016.

On June 6, 2016, we and certain of our subsidiaries, Wells Fargo Bank, National Association, as resigning trustee ("Wells Fargo") and U.S. Bank National Association, as successor trustee ("U.S. Bank"), entered into an Instrument of Resignation, Appointment and Acceptance (the "Instrument"). In connection with the Instrument, Wells Fargo resigned as trustee, note custodian, registrar and paying agent under the Indenture dated as of July 30, 2013, as supplemented and amended and we accepted such resignation and appointed U.S. Bank as the successor trustee, note custodian, registrar and paying agent under such indenture.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the 7.75% Senior Notes and the 9.25% Senior Notes and as a result, we classified $354.4 million of our outstanding amounts under the 7.75% Senior Notes, which is net of $0.3 million unamortized discount and $9.5 million deferred financing costs, and $312.1 million of our outstanding amounts under the 9.25% Senior Notes, which is net of $0.8 million unamortized discount and $8.3 million deferred financing costs, as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11.

On the Plan Effective Date, the 7.75% Senior Notes and the 9.25% Senior Notes (together with accrued but unpaid interest) will be cancelled and the holders will receive 90% of the common equity interests of New HoldCo (see Note 3).

NOTE 6 – DERIVATIVE INSTRUMENTS

We use a number of different derivative instruments, principally swaps and options, in connection with our commodity price risk management activities. We do not apply hedge accounting to any of our derivative instruments. As a result, gains and losses associated with derivative instruments are recognized in earnings.

We enter into commodity future option contracts to achieve more predictable cash flows by hedging our exposure to changes in commodity prices. At any point in time, such contracts may include regulated New York Mercantile Stock 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 were recorded at their fair values.

We recorded net derivative assets of $234.9 million and $357.7 million on our condensed consolidated balance sheets at June 30, 2016 and December 31, 2015, respectively. Of the $10.3 million of deferred gains in accumulated other comprehensive income on our condensed consolidated balance sheet at June 30, 2016, we expect to reclassify $6.9 million of gains to our condensed consolidated statement of operations over the next twelve month period as these contracts expire with the remaining gains of $3.4 million being reclassified to our condensed consolidated statements of operations in later periods as the remaining contracts expire.

Pursuant to the Restructuring Support Agreement, we completed the sale of substantially all of our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the First Lien Credit Facility.

The following table summarizes the commodity derivative activity and presentation in our condensed consolidated statements of operations for the periods indicated (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Portion of settlements associated with gains previously recognized within accumulated other comprehensive income, net of prior year offsets[1]	$5,555	$25,778	$9,070	$53,121
Portion of settlements attributable to subsequent mark to market gains	39,852	14,922	85,045	30,125
Total cash settlements on commodity derivative contracts	$45,407	$40,700	$94,115	$83,246
Gains recognized on cash settlement[2]	$4,863	$3,630	$10,651	$6,833

Gains (losses) recognized on open derivative contracts[2]	(78,127)	(30,574)	(37,795)	71,808
Gains (losses) on mark-to-market derivatives	$(73,264)	$(26,944)	$(27,144)	$78,641

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

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

Offsetting Derivatives as of June 30, 2016	Gross Amounts Recognized	Gross Amounts Offset	Net Amount Presented
Current portion of derivative assets	$ 99,654	$ —	$ 99,654
Long-term portion of derivative assets	135,231	—	135,231
Total derivative assets	$ 234,885	$ —	$ 234,885
Current portion of derivative liabilities	$ —	$ —	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ —	$ —	$ —
Offsetting Derivatives as of December 31, 2015			
Current portion of derivative assets	$ 159,460	$ —	$ 159,460
Long-term portion of derivative assets	198,262	—	198,262
Total derivative assets	$ 357,722	$ —	$ 357,722
Current portion of derivative liabilities	$ —	$ —	$ —
Long-term portion of derivative liabilities	—	—	—
Total derivative liabilities	$ —	$ —	$ —

At June 30, 2016, we had the following commodity derivatives:

Type	Production Period Ending December 31,	Volumes(1)	Average Fixed Price(1)	Fair Value Asset (in thousands)(2)	Total Type (in thousands)(2)
Natural Gas – Fixed Price Swaps	2016(3)	26,910,000	$ 4.224	$ 32,326	
	2017	50,120,000	$ 4.221	$ 51,933	
	2018	40,300,000	$ 4.168	$ 45,498	
	2019	15,860,000	$ 4.019	$ 15,945	
					$ 145,702
Natural Gas – Put Options – Drilling Partnerships	2016(3)	720,000	$ 4.150	$ 814	
					$ 814
Crude Oil – Fixed Price Swaps	2016(3)	820,500	$ 81.685	$ 26,449	
	2017	1,200,000	$ 77.610	$ 30,412	
	2018	1,080,000	$ 76.281	$ 24,184	
	2019	540,000	$ 68.371	$ 7,324	

	$ 88,369
Total net assets	$ 234,885

(1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.
(2) Fair value for natural gas fixed price swaps and natural gas put options are based on forward NYMEX natural gas prices, as applicable. Fair value of crude oil fixed price swaps are based on forward WTI crude oil prices, as applicable.
(3) The production volumes for 2016 include the remaining six months of 2016 beginning July 1, 2016.

Secured Hedge Facility

At June 30, 2016, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling

Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings are pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default will no longer be deemed to exist or to continue under the secured hedge facility.

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

NOTE 7 – FAIR VALUE OF FINANCIAL INSTRUMENTS

Assets and Liabilities Measured at Fair Value on a Recurring Basis

We use a market approach fair value methodology to value our outstanding derivative contracts. The fair value of a financial instrument depends on a number of factors, including the availability of observable market data over the contractual term of the underlying instrument. We separate the fair value of our financial instruments into the three level hierarchy (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. As of June 30, 2016 and December 31, 2015, all of our derivative financial instruments were classified as Level 2.

Information for financial instruments measured at fair value at June 30, 2016 and December 31, 2015 was as follows (in thousands):

As of June 30, 2016	Level 1	Level 2	Level 3	Total
Derivative assets				
Commodity swaps	$ —	$234,071	$ —	$234,071
Commodity puts	—	814	—	814
Total derivatives, fair value	$ —	$234,885	$ —	$234,885

As of December 31, 2015	Level 1	Level 2	Level 3	Total
Derivative assets				
Commodity swaps	$ —	$355,329	$ —	$355,329
Commodity puts	—	2,393	—	2,393

Total derivatives, fair value	$ —	$357,722	$ —	$357,722

Other Financial Instruments

Our other current assets and liabilities on our condensed consolidated balance sheets are considered to be financial instruments. The estimated fair values of these instruments approximate their carrying amounts due to their short-term nature and thus are categorized as Level 1. The estimated fair values of our long-term debt at June 30, 2016 and December 31, 2015, which consist of our Senior Notes and outstanding borrowings under our revolving credit and term loan facility (see Note 5), were $946.2 million and $907.8 million, respectively, compared with the carrying amounts of $1,587.2 million and $1,542.0 million, respectively. At June 30, 2016 and December 31, 2015, the carrying values of outstanding borrowings under our revolving credit facility (see Note 5), which bears interest at variable interest rates, approximated estimated fair value. The estimated fair values of our Senior Notes and the term loan facility were based upon the market approach and calculated using yields of our Senior Notes and the term loan credit facility 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 estimated the fair values of natural gas and oil properties transferred to us upon liquidations of certain Drilling Partnerships (see Note 8) based on discounted cash flow model, which considered the estimated remaining lives of the wells based on reserve estimates, our future operating and development costs of the assets, the respective natural gas, oil and natural gas liquids forward price curves and estimated salvage values using our historical experience and external estimates of recovery values. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

Management estimated the fair value of asset retirement obligations transferred to us upon liquidations of certain Drilling Partnerships (see Note 4) based on discounted cash flow projections using our 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 considering inflation rates, federal and state regulatory requirements, and our assumed credit-adjusted risk-free interest rate. These estimates of fair value are Level 3 measurements as they are based on unobservable inputs.

NOTE 8 – CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Relationship with ATLS. We do not directly employ any persons to manage or operate our business. These functions are provided by employees of ATLS and/or its affiliates. As of June 30, 2016 and December 31, 2015, we had a $3.4 million receivable and a $1.3 million payable, respectively, to/from ATLS related to the timing of funding cash accounts related to general and administrative expenses, such as payroll and benefits, which was recorded in advances to/from affiliates in the condensed consolidated balance sheets.

Relationship with Drilling Partnerships. We conduct certain activities through, and a portion of our revenues are attributable to, sponsorship of the Drilling Partnerships. We serve as general partner and operator of the Drilling Partnerships and assume customary rights and obligations for the Drilling Partnerships. As the general partner, we are liable for the Drilling Partnerships' liabilities and can be liable to limited partners of the Drilling Partnerships if we breach our responsibilities with respect to the operations of the Drilling Partnerships. We are entitled to receive management fees, reimbursement for administrative costs incurred and to share in the Drilling Partnership's revenue and costs and expenses according to the respective partnership agreements.

In March 2016, we transferred $36.7 million of investor capital raised and $13.3 million of accrued well drilling and completion costs incurred by us to the Atlas Eagle Ford 2015 L.P. private drilling partnership for activities directly related to their program. In June 2016, we transferred $5.2 million of funds to certain of the Drilling Partnerships that were projected to make monthly or quarterly distributions to their limited partners over the next several months and/or quarters to ensure accessible distribution funding coverage in accordance with the respective Drilling Partnerships' operations and partnership agreements in the event we experience a prolonged restructuring period as we perform all administrative and management functions for the Drilling Partnerships. On July 26, 2016, we adopted certain amendments to the Drilling Partnerships' partnership agreements, in accordance with our ability to amend the Drilling Partnerships' partnership agreements to cure an ambiguity in or correct or supplement any provision of the Drilling Partnerships' partnership agreements as may be inconsistent with any other provision, to provide that bankruptcy and insolvency events, such as the Chapter 11 Filings, with respect to the managing general partner will not cause the managing general partner to cease to serve as the managing general partner of the Drilling Partnerships nor cause the termination of the Drilling Partnerships.

We intend to continue to fund the Drilling Partnerships' operations and obligations, as necessary, until they are liquidated. Depending on commodity pricing and each of the Drilling Partnerships' reserves value, we expect to realize all outstanding receivables from the Drilling Partnerships' through the receipt of cash flows from their operations and/or the transfer of net assets and liabilities to us upon their liquidation. During the quarter ended June 30, 2016, we recorded $7.2 million and $12.4 million of gas and oil properties and asset retirement obligations, respectively, transferred to us as a result of certain Drilling Partnership liquidations. The gas and oil properties and asset retirement obligations were recorded at their fair values on the respective dates of the Drilling Partnerships' liquidation and transfer to us (see Note 7) and resulted in a non-cash loss of $6.2 million, net of liquidation and transfer adjustments, for the three and six months ended June 30, 2016, which was recorded in other income/(loss) in the condensed consolidated statements of operations.

As of June 30, 2016 and December 31, 2015, we had trade receivables of $8.9 million and a $6.6 million, respectively, from certain of the Drilling Partnerships', which were recorded in accounts receivable in the condensed consolidated balance sheets. As of June 30, 2016 and December 31, 2015, we had trade payables of $1.5 million and $3.0 million, respectively, to certain of the Drilling Partnerships', which were recorded in accounts payable in the condensed consolidated balance sheets.

Relationship with AGP. At the direction of ATLS, we charge direct costs, such as salaries and wages, and allocate indirect costs, such as rent and other general and administrative costs, to AGP based on the number of ATLS employees who devoted time to AGP's activities. In addition, Anthem Securities, Inc. ("Anthem"), a wholly owned subsidiary of us, acted as dealer manager for AGP's private placement offering, which was completed in June 2015. As the dealer manager, Anthem received compensation from AGP equal to a maximum of 12% of the gross proceeds of the private placement offering as selling commissions, marketing efforts, and other issuance costs. Anthem is currently acting as the dealer manager for AGP's issuance and sale in a continuous offering of up to a maximum agreement amount of 100,000,000 common units representing limited partner interests in AGP as further described in AGP's registration statement on Form S-1 (File No. 333-207537). AGP will pay Anthem (1) compensation equal to 3.00% of the gross proceeds of the offering (Anthem may reallow up to 1.50% of gross offering proceeds it receives as dealer manager fees to participating broker-dealers, but expects to reallow 1.25% of gross offering proceeds to participating broker-dealers); (2) 7.00% and 3.00% of aggregate gross proceeds from the sale of Class A common units and Class T common units, respectively, as sales commissions; (3) with respect to Class T common units, a distribution and unitholder servicing fee in the aggregate amount of 4.00% of the gross proceeds from the sale of Class T common units, which distribution and unitholder servicing fee will be withheld from cash distributions otherwise payable to the purchasers of Class T common units at a rate of $0.025 per quarter per unit. As of June 30, 2016 and December 31, 2015, we had a

$2.4 million receivable and $8.7 million payable, respectively, to/from AGP related to AGP's direct costs, indirect cost allocation and dealer manager costs, which was recorded in advances to/from affiliates in the condensed consolidated balance sheets.

NOTE 9 – COMMITMENTS AND CONTINGENCIES

General Commitments

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner's share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally, for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of June 30, 2016, our management believes that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

While our historical structure has varied, we have generally agreed to subordinate a portion of our share of Drilling Partnership gas and oil production revenue, net of corresponding production costs and up to a maximum of 50% of unhedged revenue, from certain Drilling Partnerships for the benefit of the limited partner investors until they have received specified returns, typically from 10% to 12% per year determined on a cumulative basis, over a specified period, typically the first five to eight years, in accordance with the terms of the partnership agreements. We periodically compare the projected return on investment for limited partners in a Drilling Partnership during the subordination period, based upon historical and projected cumulative gas and oil production revenue and expenses, with the return on investment subject to subordination agreed upon within the Drilling Partnership agreement. If the projected return on investment falls below the agreed upon rate, we recognize subordination as an estimated reduction of our pro-rata share of gas and oil production revenue, net of corresponding production costs, during the current period in an amount that will achieve the agreed upon investment return, subject to the limitation of 50% of unhedged cumulative net production revenues over the subordination period. For Drilling Partnerships for which we have recognized subordination in a historical period, if projected investment returns subsequently reflect that the agreed upon limited partner investment return will be achieved during the subordination period, we will recognize an estimated increase in our portion of historical cumulative gas and oil net production, subject to a limitation of the cumulative subordination previously recognized. For both the three months ended June 30, 2016 and 2015, $0.5 million of our gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses. For the six months ended June 30, 2016 and 2015, $0.6 million and $1.1 million, respectively, of our gas and oil production revenues, net of corresponding production costs, from certain Drilling Partnerships were subordinated, which reduced gas and oil production revenues and expenses.

As of June 30, 2016, we are committed to expend approximately $4.6 million, principally on drilling and completion expenditures.

Legal Proceedings

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

NOTE 10 – ISSUANCES OF UNITS

We have an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to $100.0 million. Sales of common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. During the three months ended June 30, 2016, we did not issue any common limited partner units under the equity distribution program. During the six months ended June 30, 2016, we issued 245,175 common limited partner units under the equity distribution program for net proceeds of $0.2 million, net of $4,000 in commissions and offering expenses paid. During the three months ended June 30, 2015, we issued 2,403,288 common limited partner units under the equity distribution program for net proceeds of $18.0 million, net of $0.5 million in commissions and offering expenses paid. During the six months ended June 30, 2015, we issued 2,885,824 common limited partner units under the equity distribution program for net proceeds of $21.4 million, net of $0.6 million in commissions and offering expenses paid.

In August 2015, we entered into a distribution agreement with MLV & Co. LLC ("MLV"), which we terminated and replaced in November 2015, when we entered into a distribution agreement with MLV and FBR Capital Markets & Co. in which we may sell our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units"). Under both the August 2015 ATM Agreement and the November 2015 ATM Agreement, we did not issue any Class D Preferred units nor Class E Preferred Units under the preferred equity distribution program for both the three and six months ended June 30, 2016 and 2015.

In May 2015, in connection with the Arkoma Acquisition, we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of $49.7 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our First Lien Credit Facility.

In April 2015, we issued 255,000 of our Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of $6.0 million.

On March 31, 2015, to partially pay our portion of a quarterly installment related to the Eagle Ford acquisition, we issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit.

On July 12, 2016, we received notification from the New York Stock Exchange ("NYSE") that the NYSE commenced proceedings to delist our common units as a result of our failure to comply with the continued listed standards set forth in Section 802.01C of the NYSE Listed Company Manual to maintain an average closing price of $1.00 per unit over a consecutive 30 day period. Our Class D Preferred Units and Class E Preferred Units were also delisted from the NYSE. Our common units, Class D Preferred Units, and Class E Preferred Units began trading on the OTC market on July 13, 2016 with the ticker symbol "ARPJ" for our common units, "ARPJP" for our Class D Preferred Units, and "ARPJN" for our Class E Preferred Units.

On May 12, 2016, due to the income tax ramifications of the potential options we were considering, the Board of Directors delayed the vesting date of approximately 110,000 units granted to employees, directors and officers until March 2017. The phantom units were set to vest between May 15, 2016 and August 31, 2016. The delayed vesting schedule did not have a significant impact on the compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the three and six months ended June 30, 2016 or our remaining unrecognized compensation expense related to such awards.

NOTE 11 – CASH DISTRIBUTIONS

We have a monthly cash distribution program whereby we distribute all of our available cash (as defined in the partnership agreement) for that month to our unitholders within 45 days from the month end. If our common unit distributions in any quarter exceed specified target levels, ATLS will receive between 13% and 48% of such distributions in excess of the specified target levels.

While outstanding, our Class B Preferred Units received regular quarterly cash distributions equal to the greater of (i) $0.40 (or $0.1333 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. In July 2015, the remaining 39,654 Class B Preferred Units were converted into common limited partner units.

Our Class C Preferred Units receive regular quarterly cash distributions equal to the greater of (i) $0.51 (or $0.17 per unit paid on a monthly basis) and (ii) the quarterly common unit distribution. On May 5, 2016, the Board of Directors elected to suspend our common unit and Class C preferred distributions, beginning with the month of March of 2016, due to the continued lower commodity price environment.

We pay quarterly distributions on our Class D Preferred Units at an annual rate of $2.15625 per unit, $0.5390625 per unit paid on a quarterly basis, or 8.625% of the $25.00 liquidation preference. We pay quarterly distributions on our Class E Preferred Units at an annual rate of $2.6875 per unit, or $0.671875 per unit on a quarterly basis, or 10.75% of the $25.00 liquidation preference. On June 16, 2016, our Board of Directors elected to suspend our quarterly distributions on our Class D Preferred Units and our Class E Preferred Units, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment. The Class D Preferred Units and Class E Preferred Units accrued distributions of $1.9 million and $0.1 million, respectively, from April 15, 2016 through June 30, 2016. However, due to the distribution suspension and our recent Chapter 11 filings, these amounts were not earned as the preferred units will be cancelled without receipt of any consideration on the Plan Effective Date.

During the six months ended June 30, 2016, we paid four monthly cash distributions totaling $5.1 million to common limited partners ($0.0125 per unit per month); $2.5 million to Preferred Class C limited partners ($0.0125 per unit per month); and $0.2 million to the General Partner Class A holder ($0.0125 per unit per month). During the six months ended June 30, 2015, we paid six monthly cash distributions totaling $71.2 million to common limited partners ($0.1966 per unit in both January and February 2015 and $0.1083 per unit in March through June 2015); $4.0 million to Preferred Class C limited partners ($0.1966 per unit in both January and February 2015 and $0.17 per unit in March through June 2015); and $3.6 million to the General Partner Class A holder ($0.1966 per unit in both January and February 2015 and $0.1083 per unit in March through June 2015).

During the six months ended June 30, 2016, we paid two distributions totaling $4.4 million to Class D Preferred units ($0.5390625 per unit) for the period October 15, 2016 through April 14, 2016. During the six months ended June 30, 2015, we paid two distributions totaling $4.1 million to Class D Preferred units ($0.6169270 per unit for the period October 2, 2014 through January 14, 2015 and $0.539063 per unit for the period January 15, 2015 through April 14, 2015).

During the six months ended June 30, 2016, we paid two distributions totaling $0.3 million to Class E Preferred units ($0.671875 per unit) for the period October 15, 2015 through April 14, 2016. No distributions were paid to Class E Preferred units during the six months ended June 30, 2015.

NOTE 12 – OPERATING SEGMENT INFORMATION

Our operations include three reportable operating segments. These operating segments reflect the way we manage our operations and make business decisions. Operating segment data for the periods indicated were as follows (in thousands):

	Three Months Ended		Six Months Ended	
	June 30, 2016	2015	June 30, 2016	2015
Gas and oil production: (1)				
Revenues(1)	$(21,867)	$70,316	$72,745	$280,150
Operating costs and expenses	(30,852)	(43,135)	(66,694)	(88,633)
Depreciation, depletion and amortization expense	(25,555)	(39,362)	(52,135)	(79,480)
Segment income (loss)	$(78,274)	$(12,181)	$(46,084)	$112,037
Well construction and completion:				
Revenues	$(1,326)	$16,956	$774	$40,611
Operating costs and expenses	1,153	(14,745)	(673)	(35,315)
Segment income (loss)	$(173)	$2,211	$101	$5,296
Other partnership management:(2)				
Revenues	$6,369	$8,853	$12,865	$18,953
Operating costs and expenses	(3,665)	(4,655)	(8,122)	(9,270)
Depreciation, depletion and amortization expense	(3,453)	(3,132)	(6,918)	(6,005)
Segment income (loss)	$(749)	$1,066	$(2,175)	$3,678
Reconciliation of segment income (loss) to net income (loss):				
Segment income (loss):				
Gas and oil production	$(78,274)	$(12,181)	$(46,084)	$112,037
Well construction and completion	(173)	2,211	101	5,296
Other partnership management	(749)	1,066	(2,175)	3,678
Total segment income (loss)	(79,196)	(8,904)	(48,158)	121,011
General and administrative expenses(3)	(23,761)	(13,287)	(40,838)	(30,422)
Interest expense(3)	(31,954)	(24,716)	(59,659)	(49,913)
Gain on early extinguishment of debt(3)	—	—	26,498	—
Gain (loss) on asset sales and disposal(3)	(502)	97	(493)	86
Other income (loss) (3)	(6,156)	—	(6,156)	—
Net income (loss)	$(141,569)	$(46,810)	$(128,806)	$40,762
Reconciliation of segment revenues to total revenues:				
Gas and oil production(1)	$(21,867)	$70,316	$72,745	$280,150
Well construction and completion	(1,326)	16,956	774	40,611
Other partnership management	6,369	8,853	12,865	18,953
Total revenues(1)	$(16,824)	$96,125	$86,384	$339,714
Capital expenditures:				
Gas and oil production	$5,210	$24,041	$17,155	$56,233
Other partnership management	416	2,700	1,550	12,794
Corporate and other	24	252	115	464
Total capital expenditures	$5,650	$26,993	$18,820	$69,491

(1)

Gas and oil production segment revenues include gains (losses) on mark to market derivatives. A $73.3 million loss on mark-to-market derivatives is included for the three months ended June 30, 2016 related to increases in commodity future prices relative to our commodity fixed price swaps during the three months ended June 30, 2016 as compared to the prior year period.

(2) 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.

(3) Gain (loss) on asset sales and disposal, general and administrative expenses, gain on early extinguishment of debt and interest expense have not been allocated to reportable segments as it would be impracticable to reasonably do so for the periods presented.

	June 30, 2016	December 31, 2015
Balance sheet:		
Goodwill:		
Well construction and completion	$6,389	$ 6,389
Other partnership management	7,250	7,250
Total goodwill	$13,639	$ 13,639
Total assets:		
Gas and oil production	$1,395,499	$ 1,551,450
Well construction and completion	7,132	27,039
Other partnership management	63,565	66,641
Corporate and other	74,190	54,819
Total assets	$1,540,386	$ 1,699,949

NOTE 13 – SUBSEQUENT EVENTS

First Lien Credit Facility Installment Payment. As part of the ongoing discussions with our lenders and noteholders, we determined not to make the first installment payment that was due under the First Lien Credit Facility on July 11, 2016 (see Note 5).

NYSE Compliance. On July 12, 2016, we received notification from the New York Stock Exchange that the NYSE commenced proceedings to delist our common units (see Note 10).

Restructuring Support Agreement. On July 25, 2016, we and certain of our subsidiaries and ATLS, solely with respect to certain sections thereof, entered into the Restructuring Support Agreement with the Restructuring Support Parties. On July 27, 2016, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court (see Note 3).

Sale of Commodity Hedge Positions. Pursuant to the Restructuring Support Agreement, we completed the sale of substantially all of our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the First Lien Credit Facility (See Note 5).

Conversion of Preferred Units and Warrants. On July 31, 2016, the 3,749,986 Class C Preferred Units that were issued to ATLS on July 31, 2013, were converted into 3,749,986 common units and the associated warrant issued to ATLS to purchase 562,497 of our common units expired.

ITEM 2:MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

BUSINESS OVERVIEW

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

Atlas Energy Group, LLC ("Atlas Energy Group" or "ATLS"; OTC: ATLS), our general partner, manages our operations and activities through its ownership interest. At June 30, 2016, Atlas Energy Group owned 100% of our general partner Class A units, all of the incentive distribution rights through which it manages and effectively controls us and an approximate 23.3% limited partner interest (20,962,485 common and 3,749,986 preferred limited partner units) in us.

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

FINANCIAL PRESENTATION

Our consolidated balance sheets at June 30, 2016 and December 31, 2015, and the consolidated statements of operations for the three and six months ended June 30, 2016 and 2015 include our accounts and our wholly-owned subsidiaries. Accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the amounts reported in the consolidated balance sheets and related consolidated statements of operations. Actual balances and results could be different from those estimates. All significant intercompany transactions and balances have been eliminated in the consolidation of the financial statements.

RECENT DEVELOPMENTS

Restructuring and Chapter 11 Bankruptcy Proceedings

On July 25, 2016, we and certain of our subsidiaries and ATLS, solely with respect to certain sections thereof, entered into a Restructuring Support Agreement (the "Restructuring Support Agreement") with (i) lenders holding 100% of our senior secured revolving credit facility (the "First Lien Lenders"), (ii) lenders holding 100% of our second lien term loan (the "Second Lien Lenders") and (iii) holders (the "Consenting Noteholders" and, collectively with the First Lien Lenders and the Second Lien Lenders, and their respective successors or permitted assigns that become party to the Restructuring Support Agreement, the "Restructuring Support Parties") of approximately 80% of the aggregate principal amount outstanding of the 7.75% Senior Notes due 2021 (the "7.75% Senior Notes") and the 9.25% Senior Notes due 2021 (the "9.25% Senior Notes" and, together with the 7.75% Senior Notes, the "Notes") of our subsidiaries, Atlas Resource Partners Holdings, LLC and Atlas Resource Finance Corporation (together, the "Issuers"). Under the Restructuring Support Agreement, the Restructuring Support Parties have agreed, subject to certain terms and conditions, to support our restructuring (the "Restructuring") pursuant to a pre-packaged plan of reorganization (the "Plan"). See "Restructuring Support Agreement," section below for further information.

On July 27, 2016, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 of the United States Bankruptcy Code ("Chapter 11") in the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court," and the cases commenced thereby, the "Chapter 11 Filings"). The cases commenced thereby are being jointly administered under the caption "In re: ATLAS RESOURCE PARTNERS, L.P., et al."

The Restructuring, including as a result of us monetizing certain hedges to pay down borrowings outstanding under our senior secured credit facility, will result in a reduction of our existing debt by approximately $900 million and elimination of approximately $80 million of our annual debt service obligations. Pursuant to the Plan, our business assets and operations will vest in a limited liability company, which will be classified as a corporation for U.S. federal income tax purposes ("New Holdco"). We expect to consummate the Plan and emerge from Chapter 11 before the end of the third quarter of 2016. Interested parties should refer to the information and the limitations and qualifications discussed in the disclosure statement related to the Restructuring (the "Disclosure Statement") which was filed as Exhibit 99.1 to our Current Report on Form 8-K filed with the Securities and Exchange Commission on July 25, 2016.

We intend to continue to operate our businesses as "debtors in possession" under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, it is contemplated that all suppliers, vendors, employees, royalty owners, trade partners and landlords will be unimpaired by the Plan and will be satisfied in full in the ordinary course of business, and our existing trade contracts and terms will be maintained. To assure ordinary course operations, we obtained interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to us, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

The Chapter 11 Filings constituted an event of default that accelerated all of our outstanding debt obligations under the First Lien Credit Facility (as defined below), the Second Lien Term Loan (as defined below) and the indenture governing the Notes. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders’ rights of enforcement are subject to the applicable provisions of Chapter 11. Accordingly, we classified all of the aforementioned outstanding debt obligations as a current liability on our condensed consolidated balance sheet as of June 30, 2016. See “Credit Facilities” section below for additional information.

The significant risks and uncertainties related to our Chapter 11 Filings raise substantial doubt about our ability to continue as a going concern. The condensed consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The condensed consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty. If we cannot continue as a going concern, adjustments to the carrying values and classification of our assets and liabilities and the reported amounts of income and expenses could be required and could be material.

Restructuring Support Agreement

On July 25, 2016, we and certain of our subsidiaries and ATLS, solely with respect to certain sections thereof, entered into the Restructuring Support Agreement with the Restructuring Support Parties. On July 27, 2016, we and certain of our subsidiaries filed voluntary petitions for relief under Chapter 11 in the Bankruptcy Court. Under the Restructuring Support Agreement, the Restructuring Support Parties have agreed, subject to certain terms and conditions, to support our Restructuring pursuant to the Plan.

In particular, under the Plan, on the Plan’s effective date (the “Plan Effective Date”), the First Lien Lenders will receive cash payment of all obligations owed to them by us pursuant to the senior secured revolving credit facility (other than $440 million of principal and face amount of letters of credit) and become lenders under an exit facility credit agreement (the “First Lien Exit Facility”), composed of a $410 million conforming reserve-based tranche and a $30 million non-conforming tranche. The non-conforming tranche will mature on May 1, 2017 and the conforming reserve-based tranche will mature on August 23, 2019. In addition, we will enter into a new second lien credit agreement (the “Second Lien Exit Facility” and, together with the First Lien Exit Facility, the “Exit Facilities”). The Second Lien Lenders will receive a pro rata share of the Second Lien Exit Facility, which will have an aggregate principal amount of $250 million plus the amounts resulting from the accrual of paid in kind interest on the principal amount of $250 million from the commencement of the Chapter 11 Filings, with interest expense paid in cash to be reduced to 2% and the remainder to be paid-in-kind from the commencement date through May 1, 2017 at a rate equal to Adjusted LIBO Rate plus 9% per annum. During the next 15-month period, cash and in-kind interest will vary based on a pricing grid tied to our leverage ratio under the revolving credit facility. After such 15-month period, interest will accrue at a rate equal to Adjusted LIBO Rate plus 9% per annum and will be payable in cash. In addition to the Second Lien Exit Facility, the Second Lien Lenders will receive a pro rata share of 10% of the common equity interests of New HoldCo, subject to dilution by a management incentive plan. Holders of the Notes, in exchange for 100% of the $668 million aggregate principal amount of Notes outstanding plus accrued but unpaid interest as of the commencement of the chapter 11 cases, will receive, on the Plan Effective Date, 90% of the common equity interests of New HoldCo as of the Plan Effective Date, subject to dilution by a management incentive plan.

Under the Plan, holders of our limited partnership units will receive no recovery. On the Plan Effective Date, all of our preferred limited partnership units and common limited partnership units will be cancelled without the receipt of any consideration.

We intend to continue to operate our businesses as “debtors in possession” under the jurisdiction of the Bankruptcy Court and in accordance with the applicable provisions of Chapter 11 and the orders of the Bankruptcy Court. Under the Plan, all suppliers, vendors, employees, royalty owners, trade partners and landlords will be unimpaired by the Plan and will be satisfied in full in the ordinary course of business, and our existing trade contracts and terms will be maintained. To assure ordinary course operations, we obtained interim approval from the Bankruptcy Court on a variety of “first day” motions, including motions seeking authority to use cash collateral on a consensual basis, pay wages and benefits for individuals who provide services to us, and pay vendors, oil and gas obligations and other creditor claims in the ordinary course of business.

Under the Plan, on the Plan Effective Date, a wholly owned subsidiary of ATLS (“ARP Mgt LLC”) will receive a preferred share of New HoldCo. The preferred share will entitle ARP Mgt LLC to receive 2% of the economics of New HoldCo (subject to dilution if catch-up contributions are not made with respect to future equity issuances, other than pursuant to a management incentive plan) and certain other rights as provided for in the Restructuring Support Agreement. Four of the seven initial members of the board of directors of New HoldCo are representatives of ARP Mgt LLC (the “New HoldCo Class A Directors”). For so long as ARP Mgt LLC holds such preferred share, the New HoldCo Class A Directors will be appointed by a majority of the Class A Directors then in office. New HoldCo will have a continuing right to purchase the preferred share at fair market value (as determined pursuant to the methodology provided for in New HoldCo's limited liability company agreement), subject to the receipt of certain approvals, including the holders of at least 67% of the outstanding common shares of New HoldCo unaffiliated with ARP Mgt LLC voting in favor of the exercise of the right to purchase the preferred share

In accordance with, and subject to the terms and conditions of, the Restructuring Support Agreement, each of the Restructuring Support Parties has agreed, among other things, to: (i) support and take all commercially reasonable actions necessary or reasonably requested by us to facilitate consummation of the Restructuring in accordance with the Plan and the related term sheets, including without limitation, if applicable, to timely vote to accept the Plan; (ii) use commercially reasonable efforts to support the confirmation of the Plan and approval of the Disclosure Statement and the solicitation procedures; (iii) not object to, delay, interfere, impede, or take any other action to delay, interfere or impede, directly or indirectly, with the Restructuring, confirmation of the Plan, or approval of the Disclosure Statement or the solicitation procedures; and (iv) not object to our efforts to enter into the Exit Facilities, and not object to, or support the efforts of any other person to oppose or object to, the Exit Facilities.

In accordance with, and subject to the terms and conditions of, the Restructuring Support Agreement, we have agreed, subject to applicable fiduciary duties, among other things, to: (i) support and complete the Restructuring and all transactions set forth in the Plan and the Restructuring Support Agreement; (ii) complete the Restructuring and all transactions set forth or described in the Plan; (iii) take any and all necessary actions in furtherance of the Restructuring, the Restructuring Support Agreement and the Plan; (iv) make commercially reasonable efforts to obtain any and all required regulatory and/or third-party approvals for the Restructuring; and (v) operate the business in the ordinary course, taking into account the Restructuring.

The Restructuring Support Agreement may be terminated upon the occurrence of certain events, including the failure to meet specified milestones related to filing, confirmation and consummation of the Plan, among other requirements, and in the event of certain breaches by the parties under the Restructuring Support Agreement. There can be no assurance that the restructuring transactions will be consummated.

Liquidation of Hedge Portfolio

On July 27, 2016, pursuant to the Restructuring Support Agreement, we completed the sale of certain of our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the First Lien Credit Facility. Accordingly, approximately $440 million remains outstanding under the First Lien Credit Facility as of July 27, 2016.

NYSE Delisting

On July 12, 2016, we received notification from the New York Stock Exchange (“NYSE”) that the NYSE commenced proceedings to delist our common units as a result of our failure to comply with the continued listed standards set forth in Section 802.01C of the NYSE Listed Company Manual to maintain an average closing price of $1.00 per unit over a consecutive 30 day period. Our Class D Preferred Units and Class E Preferred Units were also delisted from the NYSE. Our common units, Class D Preferred Units, and Class E Preferred Units began trading on the OTC market on July 13, 2016 with the ticker symbol “ARPJ” for our common units, “ARPJP” for our Class D Preferred Units, and “ARPJN” for our Class E Preferred Units.

Forbearance Agreements

On July 11, 2016, we and certain of our subsidiaries entered into two forbearance agreements: (i) with Wells Fargo Bank, National Association, as administrative agent, and the other lenders under the First Lien Credit Facility and (ii) with certain holders of our 7.75% Senior Notes and certain holders of our 9.25% Senior Notes to forbear from exercising rights and remedies arising from non-payment of the first installment of the borrowing base deficiency cure due on July 11, 2016 and any associated cross-defaults until July 27, 2016 or another event of default occurred. See “Credit Facilities – Credit Facility” section below.

Suspension of Preferred D and Preferred E Unit Distributions

On June 16, 2016, our Board of Directors elected to suspend our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units and 10.75% Class E Cumulative Redeemable Perpetual Preferred Units distributions, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment.

First Lien Credit Facility Borrowing Base Redetermination

On June 8, 2016, we received notice from Wells Fargo Bank, National Association, as administrative agent under our First Lien Credit Facility that our borrowing base had been redetermined in accordance with the First Lien Credit Facility and reduced from $700.0 million to $530.0 million. See "Credit Facilities – First Lien Credit Facility" section below.

Suspension of Common Unit and Class C Preferred Unit Distributions

On May 5, 2016, the Board of Directors elected to suspend our common unit and Class C preferred distributions, beginning with the month of March of 2016, due to the continued lower commodity price environment.

Senior Note Repurchases

In January and February 2016, we executed transactions to repurchase $20.3 million of our 7.75% Senior Notes and $12.1 million of our 9.25% Senior Notes for $5.5 million. As a result of these transactions, we recognized $26.5 million as gain on early extinguishment of debt in the first quarter of 2016. (See Item 1: "Financial Statements (Unaudited)" – Note 5 for further details).

GENERAL TRENDS AND OUTLOOK

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

The natural gas, oil and natural gas liquids commodity price markets have suffered significant declines since the fourth quarter of 2014 through the second quarter of 2016. The causes of these declines are based on a number of factors, including, but not limited to, a significant increase in natural gas, oil and NGL production. While we anticipate continued high levels of exploration and production activities over the long-term in the areas in which we operate, fluctuations in energy prices can greatly affect production rates and investments in the development of new natural gas, oil and NGL reserves.

Our future gas and oil reserves, production, cash flow, our ability to make payments on our debts and our ability to make distributions to our unitholders, including ATLS, depend on our success in producing our current reserves efficiently, developing our existing acreage and acquiring additional proved reserves economically. We face the challenge of natural production declines and volatile natural gas, oil and NGL prices. As initial reservoir pressures are depleted, natural gas and oil production from particular wells decrease. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. To the extent we do not have sufficient capital, our ability to drill and acquire more reserves will be negatively impacted. Based on current market conditions, we believe that a reduction in our debt and cash interest obligations is needed to improve our financial position and flexibility and to position us to take advantage of opportunities that may arise out of the current industry downturn.

RESULTS OF OPERATIONS

Gas and Oil Production

Production Profile. Currently, we have focused our natural gas, crude oil and NGL production operations in various plays throughout the United States. Through June 30, 2016, we have established production positions in the following operating areas:

- the Eagle Ford Shale in south Texas, in which we acquired acreage and producing wells in November 2014;
- Coal-bed Methane producing natural gas assets in (1) the Raton Basin in northern New Mexico and the Black Warrior Basin in central Alabama, acquired in 2013; (2) the Central Appalachia Basin in West Virginia and Virginia, acquired in 2014, and; (3) the Arkoma Basin in eastern Oklahoma, acquired in 2015.
- the Rangely field in northwest Colorado, a mature tertiary CO2 flood with low-decline oil production, where we have a 25% non-operated net working interest position which we acquired on June 30, 2014;
- the Appalachia Basin assets, including the Marcellus Shale, a rich, organic shale that generally contains dry, pipeline-quality natural gas, and the Utica Shale, which lies several thousand feet below the Marcellus Shale, is much thicker than the Marcellus Shale and trends primarily towards wet natural gas in the central region and dry gas in the eastern region; the Chattanooga Shale in northeastern Tennessee, which enables us to access other formations in that region such as the Monteagle and Ft. Payne Limestone; and the New Albany Shale in southwestern Indiana, a biogenic shale play with a long-lived and shallow decline profile;

- the Barnett Shale and Marble Falls play, both in the Fort Worth Basin in northern Texas. The Barnett Shale contains mostly dry gas and the Marble Falls play contains liquids rich gas and oil.
- the Mid-Continent assets, including Mississippi Lime and Hunton plays in northwestern Oklahoma, an oil and NGL-rich area, and the Niobrara Shale assets in northeastern Colorado, a predominantly biogenic shale play that produces dry gas.

The following table presents the number of wells we drilled and the number of wells we turned in line, both gross and for our interest, during the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Gross wells drilled(3):				
Barnett/Marble Falls	—	—	—	3
Mississippi Lime	—	2	—	4
Total	—	2	—	7
Net wells drilled(1):				
Barnett/Marble Falls	—	—	—	2
Mississippi Lime	—	2	—	3
Total	—	2	—	5
Gross wells turned in line(2)(3):				
Appalachia-Utica	—	4	—	4
Barnett/Marble Falls	—	—	—	14
Eagle Ford	—	—	—	2
Mississippi Lime	—	6	—	11
Total	—	10	—	31
Net wells turned in line(1)(2)(3):				
Appalachia-Utica	—	1	—	1
Barnett/Marble Falls	—	—	—	4
Eagle Ford	—	—	—	1
Mississippi Lime	—	2	—	4
Total	—	3	—	10

(1) Includes (i) our percentage interest in the wells in which we have a direct ownership interest and (ii) our percentage interest in the wells based on our percentage ownership in our Drilling Partnerships.
(2) Wells turned in line refers to wells that have been drilled, completed, and connected to a gathering system.
(3) There were no exploratory wells drilled during the three and six ended June 30, 2016 and 2015; there were no gross or net dry wells within our operating areas during the three and six months ended June 30, 2016 and 2015.

Production Volumes. The following table presents our total net natural gas, crude oil, and NGL production volumes per day in each of our operating areas and total production for the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Production volumes per day:(1)(2)				
Appalachia:(3)				
Natural gas (Mcfd)	31,010	34,230	31,278	34,692
Oil (Bpd)	322	386	308	373
NGLs (Bpd)	321	262	306	251
Total (Mcfed)	34,870	38,120	34,962	38,434
Coal-bed Methane:(3)				
Natural gas (Mcfd)	116,743	131,310	118,646	132,714
Oil (Bpd)	—	—	—	—
NGLs (Bpd)	—	—	—	—
Total (Mcfed)	116,743	131,310	118,646	132,714
Barnett/Marble Falls:				
Natural gas (Mcfd)	32,385	47,369	34,603	48,487
Oil (Bpd)	236	633	279	691
NGLs (Bpd)	1,233	2,095	1,345	2,184
Total (Mcfed)	41,198	63,740	44,347	65,736
Rangely:				
Natural gas (Mcfd)	—	—	—	—
Oil (Bpd)	2,269	2,390	2,312	2,376
NGLs (Bpd)	235	260	245	256
Total (Mcfed)	15,026	15,904	15,341	15,793
Eagle Ford:				
Natural gas (Mcfd)	471	200	430	349
Oil (Bpd)	1,188	1,500	1,275	1,525
NGLs (Bpd)	98	42	90	74
Total (Mcfed)	8,188	9,450	8,618	9,939
Mid-Continent:(3)				
Natural gas (Mcfd)	4,231	6,735	4,738	7,330
Oil (Bpd)	149	383	190	448
NGLs (Bpd)	338	534	381	574
Total (Mcfed)	7,154	12,237	8,166	13,466
Total production volumes per day:				
Natural gas (Mcfd)	184,839	219,844	189,695	223,571
Oil (Bpd)	4,164	5,293	4,364	5,412
NGLs (Bpd)	2,226	3,194	2,367	3,340
Total (Mcfed)	223,178	270,761	230,080	276,083
Total production:(1)(2)				
Natural gas (MMcf)	16,820	20,006	34,524	40,466
Oil (000's Bbls)	379	482	794	980
NGLs (000's Bbls)	203	291	431	605
Total (MMcfe)	20,309	24,639	41,875	49,971

(1) Production quantities consist of the sum of (i) our proportionate share of production from wells in which we have a direct interest, based on our proportionate net revenue interest in such wells, and (ii) our proportionate share of production from wells owned by the Drilling Partnerships in which we have an interest, based on our equity interest in each such Drilling Partnership and based on each Drilling Partnership's proportionate net revenue interest in these wells.
(2) "MMcf" represents million cubic feet; "MMcfe" represent million cubic feet equivalents; "Mcfd" represents thousand cubic feet per day; "Mcfed" represents thousand cubic feet equivalents per day; and "Bbls" and "Bpd" represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of approximately 6 Mcf to one barrel.
(3) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and the Niobrara Shale (northeastern Colorado).

Production Revenues, Prices and Costs. Our production revenues and estimated gas and oil reserves are substantially dependent on prevailing market prices for natural gas and oil. The following table presents our production revenues and average sales prices for our natural gas, oil, and natural gas liquids production for the three and six months ended June 30, 2016 and 2015 along with our average production costs, which include lease operating expenses, taxes, and transportation and compression costs, in each of the reported periods:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Production revenues (in thousands):(1)				
Appalachia:(2)				
Natural gas revenue	$3,884	$3,903	$7,679	$8,897
Oil revenue	1,758	2,473	2,959	4,686
Natural gas liquids revenue	156	193	181	434
Total revenues	$5,798	$6,569	$10,819	$14,017
Coal-bed Methane:(2)				
Natural gas revenue	$21,514	$41,134	$45,353	$88,975
Oil revenue	—	—	—	—
Natural gas liquids revenue	—	—	—	—
Total revenues	$21,514	$41,134	$45,353	$88,975
Barnett/Marble Falls:				
Natural gas revenue	$2,103	$10,306	$5,065	$22,188
Oil revenue	333	2,083	772	4,440
Natural gas liquids revenue	1,177	2,675	2,051	5,719
Total revenues	$3,613	$15,064	$7,888	$32,347
Rangely:				
Natural gas revenue	$—	$—	$—	$—
Oil revenue	11,710	18,533	19,434	34,606
Natural gas liquids revenue	616	1,129	1,105	2,117
Total revenues	$12,326	$19,662	$20,539	$36,723
Eagle Ford:				
Natural gas revenue	$116	$73	$206	$267
Oil revenue	6,802	11,337	12,662	21,244
Natural gas liquids revenue	133	74	219	184
Total revenues	$7,051	$11,484	$13,087	$21,695
Mid-Continent:(2)				
Natural gas revenue	$273	$1,132	$871	$2,762
Oil revenue	355	1,435	443	3,270
Natural gas liquids revenue	467	780	889	1,720
Total revenues	$1,095	$3,347	$2,203	$7,752
Total production revenues:				
Natural gas revenue	$27,890	$56,548	$59,174	$123,089
Oil revenue	20,958	35,861	36,270	68,246
Natural gas liquids revenue	2,549	4,851	4,445	10,174
Total revenues	$51,397	$97,260	$99,889	$201,509
Average sales price:				
Natural gas (per Mcf):(3)				
Total realized price, after hedge(4) (1)	$3.52	$3.33	$3.46	$3.46
Total realized price, before hedge(4)	$1.70	$2.14	$1.74	$2.34

Oil (per Bbl):[3]				
Total realized price, after hedge[1]	$81.16	$83.19	$79.06	$81.98
Total realized price, before hedge	$42.08	$53.35	$35.50	$48.32
Natural gas liquids (per Bbl):[3]				
Total realized price, after hedge[1]	$12.59	$22.58	$10.32	$22.53
Total realized price, before hedge	$12.59	$13.78	$10.32	$13.95
Production costs (per Mcfe):[2] [3]				
Appalachia:				
Lease operating expenses[5]	$0.63	$1.07	$0.74	$1.07
Production taxes	0.05	0.06	0.06	0.06
Transportation and compression	0.21	0.27	0.23	0.30
	$0.90	$1.41	$1.02	$1.43

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
Coal-bed Methane:				
Lease operating expenses	$0.96	$1.03	$0.99	$1.05
Production taxes	0.16	0.20	0.16	0.22
Transportation and compression	0.22	0.35	0.27	0.34
	$1.34	$1.59	$1.42	$1.60
Barnett/Marble Falls:				
Lease operating expenses	$0.78	$1.26	$0.88	$1.34
Production taxes	0.19	0.17	0.18	0.18
Transportation and compression	0.29	0.07	0.25	0.07
	$1.25	$1.50	$1.30	$1.58
Rangely:				
Lease operating expenses	$4.37	$4.65	$4.36	$4.34
Production taxes	0.60	(0.02)	0.58	0.49
Transportation and compression	0.01	—	0.01	—
	$4.98	$4.64	$4.95	$4.83
Eagle Ford:				
Lease operating expenses	$1.74	$2.06	$1.75	$1.82
Production taxes	0.47	0.40	0.42	0.35
Transportation and compression	0.14	0.14	0.12	0.09
	$2.35	$2.61	$2.29	$2.26
Mid-Continent:				
Lease operating expenses	$1.58	$1.58	$1.58	$1.51
Production taxes	0.07	0.08	0.07	0.08
Transportation and compression	0.30	0.28	0.30	0.27
	$1.96	$1.93	$1.95	$1.85
Total production costs:				
Lease operating expenses(5)	$1.15	$1.36	$1.20	$1.36
Production taxes	0.18	0.16	0.18	0.20
Transportation and compression	0.22	0.24	0.24	0.24
	$1.56	$1.77	$1.62	$1.79

(1) Production revenue excludes the impact of cash settlements on commodity derivative contracts not previously included within accumulated other comprehensive income following our decision to de-designate hedges beginning on January 1, 2015 (see Item 1: "Financial Statements (Unaudited) – Note 6"). Cash settlements on commodity derivative contracts excluded from production revenues consisted of $30.1 million and $9.0 million for natural gas and $9.8 million and $4.2 million for oil for the three months ended June 30, 2016 and 2015, respectively; $58.5 million and $14.6 million for natural gas and $26.5 million and $12.1 million for oil for the six months ended June 30, 2016 and 2015, respectively. Cash settlements on natural gas liquids contracts excluded from production revenues consisted of $1.7 million and $3.4 million for the three and six months ended June 30, 2015, respectively.

(2) Appalachia includes our production located in Pennsylvania, Ohio, New York, West Virginia (excluding the Cedar Bluff area) and the Chattanooga (Tennessee) and New Albany (Indiana) Shales; Coal-bed methane includes our production located in the Raton Basin in northern New Mexico, the Black Warrior Basin in central Alabama, the Cedar Bluff area of West Virginia and Virginia, and the Arkoma Basin in eastern Oklahoma; Mid-Continent includes our production located in the Mississippi Lime and Hunton plays and Niobrara Shale (northeastern Colorado).

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

(4) Excludes the impact of subordination of our production revenue to investor partners within our Drilling Partnerships for the three and six months ended June 30, 2016 and 2015. Including the effect of this subordination, the average realized gas sales price was $3.45 per Mcf ($1.63 per Mcf before the effects of financial hedging) and $3.28 per Mcf ($2.09 per Mcf before the effects of financial hedging) for the three months ended June 30, 2016 and 2015, respectively, and $3.41 per Mcf ($1.69 per Mcf before the effects of financial hedging) and $3.40 per Mcf ($2.29 per Mcf before the effects of financial hedging) for the six months ended June 30, 2016 and 2015, respectively.

(5) Excludes the effects of our proportionate share of lease operating expenses associated with subordination of our production revenue to investor partners within our Drilling Partnerships for the three and six months ended June 30, 2016 and 2015. Including the effects of these costs, Appalachia lease operating expenses were $0.39 per Mcfe ($0.66 per Mcfe for total production costs) and $0.92 per Mcfe ($1.26 per Mcfe for total production costs) for the three months ended June 30, 2016 and 2015, respectively, and $0.53 per Mcfe ($0.81 per Mcfe for total production costs) and $0.92 per Mcfe ($1.28 per Mcfe for total production costs) for the six months ended June 30, 2016 and 2015, respectively. Including the effects of these costs, total lease operating expenses per Mcfe were $1.12 per Mcfe ($1.52 per Mcfe for total production costs) and $1.34 per Mcfe ($1.75 per Mcfe for total production costs) for the three months ended June 30, 2016 and 2015, respectively, and $1.17 per Mcfe ($1.59 per Mcfe for total production costs) and $1.34 per Mcfe ($1.77 per Mcfe for total production costs) for the six months ended June 30, 2016 and 2015.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Gas and oil production revenues	$51,397	$97,260	$99,889	$201,509
Gas and oil production costs	$30,852	$43,135	$66,694	$88,633

The $45.9 million decrease in gas and oil production revenues consisted of a $19.6 million decrease during the three months ended June 30, 2016 as compared to the prior year period attributable to our Coal-bed Methane operations, an $11.5 million decrease attributable to our Barnett Shale/Marble Falls operations, a $7.3 million decrease associated with our Rangely operations, a $4.4 million decrease attributable to our Eagle Ford operations, a $2.3 million decrease attributable to our Mid-Continent operations and a $0.8 million decrease attributable to our Appalachia operations. Our gas and oil production revenue decreases in all operating areas were attributed to lower production volumes and decreases in commodity prices compared to the prior year period.

The $101.6 million decrease in gas and oil production revenues consisted of a $43.6 million decrease during the six months ended June 30, 2016 as compared to the prior year period attributable to our Coal-bed Methane operations, a $24.5 million decrease attributable to our Barnett Shale/Marble Falls operations, a $16.2 million decrease associated with our Rangely operations, an $8.6 million decrease attributable to our Eagle Ford operations, a $5.5 million decrease attributable to our Mid-Continent operations and a $3.2 million decrease attributable to our Appalachia operations. Our gas and oil production revenue decreases in all operating areas were attributed to lower production volumes and decreases in commodity prices compared to the prior year period.

The $12.3 million decrease in gas and oil production expenses primarily consisted of a $4.7 million decrease during the three months ended June 30, 2016 as compared to the prior year period attributable to our Coal-bed Methane operations, a $4.0 million decrease attributable to our Barnett Shale/Marble Falls operations, a $2.3 million decrease attributable to our Appalachia operations, a $0.9 million decrease attributable to our Mid-Continent operations and a $0.5 million decrease attributable to our Eagle Ford operations, partially offset by a $0.1 million increase attributable to our Rangely operations. Total production costs per Mcfe decreased between the periods primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

The $21.9 million decrease in gas and oil production expenses during the six months ended June 30, 2016 as compared to the prior year period primarily consisted of an $8.3 million decrease attributable to our Barnett Shale/Marble Falls operations, a $7.8 million decrease attributable to our Coal-bed Methane operations, a $3.7 million decrease attributable to our Appalachia operations, a $1.6 million decrease attributable to our Mid-Continent operations and a $0.5 million decrease attributable to our Eagle Ford operations. Total production costs per Mcfe decreased between the periods primarily as a result of continued efforts to reduce operating costs in each of our areas of production.

PARTNERSHIP MANAGEMENT

Well Construction and Completion

Drilling Program Results. The number of wells we drill will vary within the partnership management segment depending on the amount of capital we raise through our Drilling Partnerships, the cost of each well, the depth or type of each well, the estimated recoverable reserves attributable to each well and accessibility to the well site. Well construction and completion revenues and costs and expenses incurred represent the billings and costs associated with the completion of wells for Drilling Partnerships we sponsor. As our drilling contracts with the Drilling Partnerships are on a “cost-plus” basis, an increase or decrease in our average cost per well also results in a proportionate increase or decrease in our average revenue per well, which directly affects the number of wells we drill. The following table presents the amounts of Drilling Partnership investor capital raised and deployed, as well as sets forth information relating to these revenues and the related costs and number of net wells associated with these revenues during the periods indicated (dollars in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Drilling partnership investor capital:				
Raised	$—	$—	$—	$—
Deployed	$—	$16,956	$2,100	$40,611
Average construction and completion:				
Revenue per well	$—	$6,472	$1,548	$3,136
Cost per well	—	5,628	1,346	2,727
Gross profit per well	$—	$844	$202	$409
Gross profit margin	$(173)	$2,211	$101	$5,296
Partnership net wells associated with revenue recognized(1):				
Appalachia - Utica	—	2	—	2
Marble Falls	—	—	—	5
Eagle Ford	—	—	1	1
Mississippi Lime	—	1	—	5
Total	—	3	1	13

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

The $2.4 million and $5.2 million decreases in well construction and completion gross profit margin during the three and six month periods ended June 30, 2016, respectively, as compared to the respective prior year period was due to a decrease in the number of partnership wells for which completion activities were being performed related to timing and the economics of such activities during the challenging commodity price environment along with a downward revision to our estimated total costs to complete wells, which resulted in an unfavorable adjustment to our gross profit margin recognized on our percentage of completion basis for the wells in progress.

Administration and Oversight

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Administration and oversight revenues	$495	$547	$950	$1,806

Administration and oversight fee revenues represent supervision and administrative fees earned for the drilling and subsequent ongoing management of wells for our Drilling Partnerships. Typically, we receive a lower administration and oversight fee related to shallow, vertical wells we drill within the Drilling Partnerships, such as those in the Marble Falls play, as compared to deep, horizontal wells, such as those drilled in the Marcellus and Utica Shales. The following table presents the number of gross and net development wells we drilled for our Drilling Partnerships during three and six months ended June 30, 2016 and 2015. There were no exploratory wells drilled during the three and six months ended June 30, 2016 and 2015:

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Gross partnership wells drilled:				
Barnett/Marble Falls	—	—	—	2
Mississippi Lime/Hunton	—	—	—	2
Total	—	—	—	4
Net partnership wells drilled:				
Barnett/Marble Falls	—	—	—	2
Mississippi Lime/Hunton	—	—	—	1
Total	—	—	—	3

The $0.9 million decrease in administration and oversight fee revenues during the six months ended June 30, 2016 compared to the prior year period was primarily due to a decrease in the number of wells spud within the six months ended June 30, 2016 compared with the prior year period.

Well Services

	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
	(in thousands)		(in thousands)	
Well services revenues	$4,190	$6,102	$8,622	$12,726
Well services expenses	$1,474	$2,139	$3,652	$4,337

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

The $1.9 million and $4.1 million decreases in well services revenue during the three and six month periods ended June 30, 2016, respectively, as compared to the respective prior year period is primarily related to lower fee revenue associated with our salt water gathering and disposal systems within the Mississippi Lime and Marble Falls operating areas, which are utilized by our Drilling Partnership wells, and an increased number of wells having been shut in, which results in a reduction of the monthly operating fees which we charge the Drilling Partnerships.

The $0.7 million decreases in well services expenses during the three and six months ended June 30, 2016 as compared to the prior year periods are primarily related to lower labor costs.

Gathering and Processing

	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Gathering and processing margin	$(591)	$(339)	$(1,375)	$(572)

Gathering and processing margin includes gathering fees we charge to our Drilling Partnership wells and the related expenses and gross margin for our processing plants in the New Albany Shale and the Chattanooga Shale. Generally, we charge a gathering fee to our Drilling Partnership wells equivalent to the fees we remit. In Appalachia, a majority of our Drilling Partnership wells are subject to a gathering agreement, whereby we remit a gathering fee of 16%. However, based on the respective Drilling Partnership agreements, we charge our Drilling Partnership wells a 13% gathering fee. As a result, some of our gathering expenses within our partnership management segment, specifically those in the Appalachian Basin, will generally exceed the revenues collected from the Drilling Partnerships by approximately 3%.

The $0.3 million and $0.8 million unfavorable movements in gathering and processing margin during the three and six month periods ended June 30, 2016, respectively, as compared to the respective prior year period was principally due to lower overall natural gas prices in Appalachia and lower gathering fees, particularly from our Marcellus Shale Drilling Partnership wells in Northeastern Pennsylvania, which are utilizing our gathering pipeline.

OTHER REVENUES AND EXPENSES

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
	(in thousands)		(in thousands)	
Other Revenues				
Gain (loss) on mark-to-market derivatives	$(73,264)	$(26,944)	$(27,144)	$78,641
Other, net	84	27	198	60
Other Expenses				
General and administrative	$23,761	$13,287	$40,838	$30,422
Depreciation, depletion and amortization	29,008	42,494	59,053	85,485
Interest expense	31,954	24,716	59,659	49,913
Gain (loss) on asset sales and disposal	(502)	97	(493)	86
Gain on extinguishment of debt	—	—	26,498	—
Other income (loss)	(6,156)	—	(6,156)	—

Gain (Loss) on Mark-to-Market Derivatives. We recognize changes in the fair value of our derivatives immediately within gain (loss) on mark-to-market derivatives on our condensed consolidated statements of operations. The recognized losses during the three and six month periods ended June 30, 2016 are due to increases in commodity future prices during each respective period.

General and Administrative. The $10.5 million increase in general and administrative expenses for the three months ended June 30, 2016 as compared to the prior year period is primarily due to a $7.4 million increase in restructuring costs to various financial advisors and legal counsel, a $2.1 million increase in salaries, wages and benefits and a $1.9 million increase in syndication expense due to lower program fundraising activities, partially offset by a $1.1 million decrease in non-cash stock compensation.

The $10.4 million increase in general and administrative expenses for the six months ended June 30, 2016 as compared to the prior year period is primarily due to an $8.5 million increase in salaries, wages and benefits, a $5.6 million increase in restructuring costs to various financial advisors and legal counsel, and a $1.4 million increase in syndication expenses due to lower program fundraising activities, partially offset by a $4.5 million decrease in non-cash stock compensation and a $0.5 million decrease in other corporate expenses.

Depreciation, Depletion and Amortization. The decrease in depreciation, depletion and amortization for the three and six month periods ended June 30, 2016 as compared to the respective prior year period was primarily due to a $13.8 million and $27.3 million decrease in our depletion expense, respectively. The following table presents total depletion expense, depletion as a percent of gas and oil production revenue and depletion expense per Mcfe for our operations for the respective periods (in thousands, except for percentage and per Mcfe data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Depletion expense:				
Total	$25,555	$39,362	$52,135	$79,480
Depletion expense as a percentage of gas and oil production revenue	50 %	40 %	52 %	39 %
Depletion per Mcfe	$1.26	$1.60	$1.25	$1.59

Depletion expense varies from period to period and is directly affected by changes in our gas and oil reserve quantities, production levels, product prices and changes in the depletable cost basis of our gas and oil properties. The decreases in depletion expense and depletion expense per Mcfe when compared with the comparable prior year periods were due to impairments of our proved properties recorded in the third and fourth quarters of 2015 as a result of lower forecasted commodity prices, which reduced the depletable cost basis of our proved gas and oil properties in the current year periods. The increases in the depletion expense as a percentage of gas and oil revenues when compared with the comparable prior year periods were due to decreases in our gas and oil revenues as a result of lower commodity prices and production volumes in the current year periods, partially offset by the decreases in depletion expense described above.

Interest Expense. The increase in our interest expense during the three months ended June 30, 2016 as compared to the prior year period consisted of $4.1 million in accelerated amortization related to the reduction of the borrowing base of our First Lien Credit Facility in June 2016, a $1.9 million increase associated with higher outstanding borrowings under our First Lien Credit Facility, a $1.7 million decrease in capitalized interest due to lower capital spending and a $0.2 million increase associated with amortization of our deferred financing costs, partially offset by a $0.7 million decrease associated with interest expense on our Senior Notes due to our repurchases in January and February of 2016.

The increase in our interest expense during the six months ended June 30, 2016 as compared to the prior year period consisted of $4.1 million associated with accelerated amortization of our deferred financing costs resulting from a reduction of the borrowing base of our First Lien Credit Facility in June 2016, a $3.8 million increase associated with our Term Loan Facility entered into February 2015, a $3.2 million decrease in capitalized interest due to lower capital spending, a $2.7 million increase associated with higher outstanding borrowings under our First Lien Credit Facility and a $1.3 million increase associated with amortization of our deferred financing costs, partially offset by a $4.3 million decrease associated with accelerated amortization of our deferred financing costs resulting from a reduction of the borrowing base of our credit facility in February 2015 and a $1.1 million decrease associated with interest expense on our Senior Notes due to our repurchases in January and February of 2016.

Gain on Early Extinguishment of Debt. The gain on early extinguishment of debt for the six months ended June 30, 2016 represents a $26.5 million gain related to the repurchase of a portion of our 7.75% and 9.25% Senior Notes. Of the $26.5 million gain, $27.4 million related to the gain from the redemption of the principal values and accrued interest, partially offset by $0.9 million related to the accelerated amortization of the related deferred financing costs.

Other income (loss). The $6.2 million loss for the six months ended June 30, 2016 represents a non-cash loss, net of liquidation and transfer adjustments, of certain Drilling Partnerships' liquidation and transfer of oil and gas properties and asset retirement obligations to us.

LIQUIDITY AND CAPITAL RESOURCES

General

Our primary sources of liquidity are cash generated from operations, capital raised through our Drilling Partnerships, and borrowings under our revolving credit facility (see "Credit Facilities"). Our primary cash requirements, in addition to normal operating expenses, are for debt service, capital expenditures and distributions to our limited partners and general partner. In general, we expect to fund:

- cash distributions and maintenance capital expenditures through existing cash and cash flows from operating activities;
- expansion capital expenditures and working capital deficits through cash generated from operations, additional borrowings and capital raised through Drilling Partnerships; and
- debt service principal payments through additional borrowings as they become due or by the issuance of additional limited partner units or asset sales.

We have historically funded our operations, acquisitions and cash distributions primarily through cash generated from operations, amounts available under our credit facilities and equity and debt offerings. Our future cash flows are subject to a number of variables, including oil and natural gas prices. Prices for oil and natural gas began to decline significantly during the fourth quarter of 2014 and have continued to decline and remain low in 2016. These lower commodity prices have negatively impacted our revenues, earnings and cash flows. Sustained low commodity prices have had a material and adverse effect on our liquidity position.

Based on current market conditions, we believe that a reduction in our debt and cash interest obligations is needed to improve our financial position and flexibility and to position us to take advantage of opportunities that may arise out of the current industry downturn. See “Recent Developments – Restructuring and Chapter 11 Bankruptcy Proceedings” and “Restructuring Support Agreement” section above for further information regarding our Restructuring Support Agreement and Restructuring Plan under our Chapter 11 Filings.

Cash Flows – Six Months Ended June 30, 2016 Compared with the Six Months Ended June 30, 2015

	Six Months Ended June 30,	
	2016	2015
Net cash provided by (used in) operating activities	(17,309)	53,185
Net cash used in investing activities	(18,820)	(106,291)
Net cash provided by financing activities	59,034	38,466

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The change in cash flows provided by (used in) operating activities when compared with the comparable prior year period was primarily due to:

- a decrease in our gas and oil production revenues of $101.6 million, due to lower commodity pricing and production volumes;

- a decrease in our well construction and completion and well services margins totaling $8.6 million, due to lower revenue generating activities, partially offset by lower associated expenses;

- an increase in general and administrative expenses of $10.4 million due to higher salaries, wages, and benefits and costs associated with our restructuring; and

- an increase in cash interest of $6.4 million due to higher outstanding balances on our revolving credit facility and the debt under our term loan facility issued in February 2015, partially offset by our senior note repurchases in January and February 2016;

- partially offset by a decrease in oil and gas production costs of $21.9 million due to cost control measures and lower production activities; and

- an increase in our working capital of $37.7 million primarily due to decreases in accounts payable, accrued liabilities and liabilities associated with drilling contracts as a result of lower operating activities, an increase due to derivative cash settlements; and a decrease in advances to affiliates; partially offset by lower accounts receivable, as a result of revenue declines, lower subscription receivables, due to a decline in fund raising for well drilling activities, and an increase in cash outflow for well drilling liabilities.

The change in cash flows used in investing activities when compared with the comparable prior year period was primarily due to:

- a decrease of $50.7 million in capital expenditures due to lower capital expenditures related to our drilling activities; and
- a decrease of $37.0 million in net cash paid for acquisitions due to adjustments in working capital settlements for our Eagle Ford acquisition in 2015.

The change in cash flows provided by financing activities when compared with the comparable prior year period was primarily due to:

- an increase of $223.5 million in net borrowings on our revolving credit facility;
- a decrease of $71.0 million in distributions paid to unitholders primarily due to a reduction in our monthly cash distribution per common limited partner unit from $0.1966 per unit to $0.0125 per unit through the month of February 2016, and suspension of our monthly cash distributions beginning with the month of March of 2016, due to the continued lower commodity price environment;
- a decrease of $35.4 million related to the Arkoma transaction adjustment reflected in the first half of 2015; and
- a decrease of $15.4 million in deferred financing costs primarily related to the issuance of our $250.0 million second lien term loan in the first half 2015; partially offset by
- a decrease of $242.5 million in net borrowings under our second lien term loan facility due to the second lien term loan proceeds of $242.5 million, net of $7.5 million in discount, issued in the first half of 2015;
- a decrease of $6.0 million in net proceeds from the issuance of common limited partner units in the first half of 2015 under our equity distribution programs; and

- an increase of $5.5 million related to our senior note repurchases in the first quarter of 2016.

Capital Requirements

At June 30, 2016, the capital requirements of our natural gas and oil production primarily consist of expenditures to maintain or increase production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures. The following table summarizes our total capital expenditures, excluding amounts paid for acquisitions, for the periods presented (in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Total capital expenditures	$5,650	$26,993	$18,820	$69,491

During the three months ended June 30, 2016, our total capital expenditures consisted primarily of $2.2 million for wells drilled exclusively for our own account compared with $13.5 million for the comparable prior year period, a reduction of $0.2 million of investments in our Drilling Partnerships compared with $5.1 million for the prior year comparable period, $0.8 million of leasehold acquisition costs compared with $1.4 million for the prior year comparable period and $2.9 million of corporate and other costs compared with $7.0 million for the prior year comparable period.

During the six months ended June 30, 2016, our total capital expenditures consisted primarily of $9.8 million for wells drilled exclusively for our own account compared with $25.8 million for the comparable prior year period, $0.6 million of investments in our Drilling Partnerships compared with $18.7 million for the prior year comparable period, $2.0 million of leasehold acquisition costs compared with $3.8 million for the prior year comparable period and $6.4 million of corporate and other costs compared with $21.2 million for the prior year comparable period.

We continuously evaluate acquisitions of gas and oil assets. In order to make any acquisitions in the future, we believe we will be required to access outside capital either through debt or equity placements or through joint venture operations with other energy companies. There can be no assurance that we will be successful in our efforts to obtain outside capital. As of June 30, 2016, we are committed to expend approximately $4.6 million on drilling and completion and other capital expenditures, excluding acquisitions. We expect to fund these capital expenditures primarily with cash flow from operations, capital raised through our Drilling Partnerships and borrowings under our revolving credit facility.

OFF BALANCE SHEET ARRANGEMENTS

As of June 30, 2016, our off-balance sheet arrangements were limited to our letters of credit outstanding of $4.2 million and commitments to spend $4.6 million related to our drilling and completion and capital expenditures, excluding acquisitions.

We are the ultimate managing general partner of the Drilling Partnerships and have agreed to indemnify each investor partner from any liability that exceeds such partner’s share of Drilling Partnership assets. We have structured certain Drilling Partnerships to allow limited partners to have the right to present their interests for purchase. Generally, for Drilling Partnerships with this structure, we are not obligated to purchase more than 5% to 10% of the units in any calendar year, no units may be purchased during the first five years after closing for the Drilling Partnership, and we may immediately suspend the presentment structure for a Drilling Partnership by giving notice to the limited partners that we do not have adequate liquidity for redemptions. In accordance with the Drilling Partnership agreement, the purchase price for limited partner interests would generally be based upon a percentage of the present value of future cash flows allocable to the interest, discounted at 10%, as of the date of presentment, subject to estimated changes by us to reflect current well performance, commodity prices and production costs, among other items. Based on our historical experience, as of June 30, 2016, we believe that any such estimated liability for redemptions of limited partner interests in Drilling Partnerships which allow such transactions would not be material.

CREDIT FACILITIES

First Lien Credit Facility

We are a party to a Second Amended and Restated Credit Agreement, dated as of July 31, 2013 by and among us, the lenders from time to time party thereto, and Wells Fargo Bank, National Association, as administrative agent, as amended, supplemented or modified from time to time (the "First Lien Credit Facility"), which provides for a senior secured revolving credit facility with a maximum borrowing base of $1.5 billion scheduled to mature in July 2018.

On June 8, 2016, we received notice from Wells Fargo Bank, National Association, as administrative agent under our First Lien Credit Facility that our borrowing base had been redetermined in accordance with the First Lien Credit Facility and reduced from $700.0 million to $530.0 million. As of June 30, 2016, $669.5 million in borrowings were outstanding (which includes $4.2 million in letters of credit) under the First Lien Credit Facility, resulting in a borrowing base deficiency of $143.7 million. Our First Lien Credit Facility provides that within 30 days after our receipt of a notification of a borrowing base deficiency, we must elect to cure the borrowing base deficiency through any combination of the following actions: (i) repay amounts outstanding under the First Lien Credit Facility sufficient to cure the borrowing base deficiency, either within 30 days after receipt of the borrowing base deficiency notice or in four equal monthly installments beginning on July 11, 2016; or (ii) pledge as collateral additional oil and gas properties acceptable to the administrative agent and lenders sufficient to cure the borrowing base deficiency within 60 days after receipt of the borrowing base deficiency notice.

As part of the discussions with our lenders and noteholders (see “Recent Developments – Restructuring and Chapter 11 Bankruptcy Proceedings” and “Restructuring Support Agreement” sections above), we determined not to make the first installment payment that was due on July 11, 2016.

In connection therewith and in support of negotiations with our First Lien Lenders, Second Lien Lenders, and Consenting Noteholders, on July 11, 2016, we and certain of our subsidiaries entered into two forbearance agreements: (i) with Wells Fargo Bank, National Association, as administrative agent, and the other lenders under the First Lien Credit Facility (the “First Lien Credit Forbearance”) and (ii) with the Consenting Noteholders of our 7.75% Senior Notes and 9.25% Senior Notes (the “Notes Forbearance”).

Pursuant to the First Lien Credit Forbearance, the administrative agent and the lenders representing approximately 81% of the outstanding indebtedness under the First Lien Credit Facility agreed to forbear from exercising their rights and remedies arising from non-payment of the first installment of the borrowing base deficiency cure due on July 11, 2016 and related cross-defaults (the “Specified Default”) until the earliest to occur of (i) July 27, 2016, (ii) the occurrence of an event of default under the First Lien Credit Facility (unrelated to the Specified Default) or (iii) the exercise by any holder of indebtedness outstanding under the Second Lien Term Loan, the Notes or any other material indebtedness of ours of rights or remedies against us or the other loan parties or their respective property.

Pursuant to the Notes Forbearance, the holders of approximately 78% of the aggregate outstanding principal amount of the 7.75% Senior Notes and approximately 82% of the 9.25% Senior Notes agreed to forbear from exercising their rights and remedies arising from the cross-default that resulted from the Specified Default until the earliest to occur of (i) July 27, 2016, (ii) another event of default under the 7.75% Senior Notes indenture or the 9.25% Senior Notes indenture or (iii) any other holder of the Notes commences a legal proceeding against us or the other loan parties or their respective property. The holders of a majority of the Second Lien Term Loan were supportive of the forbearance.

Our borrowing base is scheduled for semi-annual redeterminations in May and November of each year. Up to $20.0 million of the First Lien Credit Facility may be in the form of standby letters of credit, of which $4.2 million was outstanding at June 30, 2016. Our obligations under the First Lien Credit Facility are secured by mortgages on our oil and gas properties and first priority security interests in substantially all of our assets. Additionally, obligations under the First Lien Credit Facility are guaranteed by certain of our material subsidiaries, and any non-guarantor subsidiaries of ours are minor. At June 30, 2016, the weighted average interest rate on outstanding borrowings under the First Lien Credit Facility was 4.0%.

The First Lien Credit Facility contains customary covenants including, without limitation, covenants that limit our ability to incur additional indebtedness (but which permits second lien debt in an aggregate principal amount of up to $300.0 million and third lien debt that satisfies certain conditions including pro forma financial covenants), grant liens, make loans or investments, make distributions if a borrowing base deficiency or default exists or would result from the distribution, merger or consolidate with other persons, or engage in certain asset dispositions including a sale of all or substantially all of our assets. The First Lien Credit Facility also requires us to maintain a ratio of First Lien Debt to EBITDA (ratio as defined in the First Lien Credit Facility agreement) of not greater than 2.75 to 1.00, and a ratio of current assets to current liabilities (ratio as defined in the First Lien Credit Facility agreement) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter. We were not in compliance with these covenants as of June 30, 2016.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the First Lien Credit Facility and as a result, we classified $669.5 million of our outstanding amounts under the First Lien Credit Facility as current portion of long-term debt and $12.2 million of deferred financing costs related to the First Lien Credit Facility as current assets within our condensed consolidated balance sheet as of June 30, 2016. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders’ rights of enforcement are subject to the applicable provisions of Chapter 11.

Pursuant to the Restructuring Support Agreement, we completed the sale of substantially all of our commodity hedge positions on July 25, 2016 and July 26, 2016 and used the proceeds to repay $233.5 million of borrowings outstanding under the First Lien Credit Facility. Accordingly, approximately $440 million remained outstanding under the First Lien Credit Facility as of July 27, 2016, the date of the Chapter 11 Filings.

On the Plan Effective Date, we expect to enter into the new First Lien Exit Facility, which will replace the First Lien Credit Facility (see “Restructuring Support Agreement” above).

Second Lien Term Loan

We are party to a Second Lien Credit Agreement, dated as of February 23, 2015 by and among us, the lenders from time to time party thereto, and Wilmington Trust, National Association, as administrative agent, as amended, supplemented or modified from time to time (the “Second Lien Term Loan”), which provides for a second lien term loan in an original principal amount of $250.0 million.

The Second Lien Term Loan matures on February 23, 2020. The Second Lien Term Loan is presented in the table above net of unamortized discount of $5.5 million as of June 30, 2016.

Our obligations under the Second Lien Term Loan are secured on a second priority basis by security interests in all of our assets and those of our restricted subsidiaries that guarantee our existing First Lien Credit Facility. In addition, the obligations under the Second Lien Term Loan are guaranteed by our material restricted subsidiaries. At June 30, 2016, the weighted average interest rate on outstanding borrowings under the Second Lien Term Loan was 10.0%.

The Second Lien Term Loan contains customary covenants including, without limitation, covenants that limit our ability to make restricted payments, take on indebtedness, issue preferred units, grant liens, conduct sales of assets and subsidiary stock, make distributions from restricted subsidiaries, conduct affiliate transactions and engage in other business activities. In addition, the Second Lien Term Loan contains covenants substantially similar to those in the First Lien Credit Facility, including, among others, restrictions on swap agreements, debt of unrestricted subsidiaries, drilling and operating agreements and the sale or discount of receivables. We were not in compliance with the financial covenants as of June 30, 2016.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the Second Lien Term Loan and as a result, we classified $244.5 million of our outstanding amounts under the Second Lien Term Loan, which is net of $5.5 million unamortized discount and $9.4 million deferred financing costs, as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11.

On the Plan Effective Date, we expect to enter into the new Second Lien Exit Facility, which will replace the Second Lien Term Loan (see "Restructuring Support Agreement" above).

Senior Notes

At June 30, 2016, we had $354.4 million outstanding of our 7.75% Senior Notes due 2021. The 7.75% Senior Notes were presented net of a $0.3 million unamortized discount as of June 30, 2016.

At June 30, 2016, we had $312.1 million outstanding of our 9.25% Senior Notes due 2021. The 9.25% Senior Notes were presented net of a $0.8 million unamortized discount as of June 30, 2016.

In January and February 2016, we executed transactions to repurchase $20.3 million of our 7.75% Senior Notes and $12.1 million of our 9.25% Senior Notes for $5.5 million, which includes $0.6 million of interest. As a result of these transactions, we recognized $26.5 million as gain on early extinguishment of debt, net of accelerated amortization of deferred financing costs of $0.9 million, in our condensed consolidated statement of operations for the six months ended June 30, 2016.

The 7.75% Senior Notes and 9.25% Senior Notes are guaranteed by certain of our material subsidiaries. The guarantees under the 7.75% Senior Notes and 9.25% Senior Notes are full and unconditional and joint and several, subject to certain customary automatic release provisions, including, in certain circumstances, the sale or other disposition of all or substantially all the assets of, or all of the equity interests in, the subsidiary guarantor, or the subsidiary guarantor is declared "unrestricted" for covenant purposes, and any subsidiaries of ours, other than the subsidiary guarantors, are minor. There are no restrictions on our ability to obtain cash or any other distributions of funds from the guarantor subsidiaries.

The indentures governing the 7.75% Senior Notes and 9.25% Senior Notes contain covenants including, without limitation, covenants that limit our ability to incur certain liens, incur additional indebtedness; declare or pay distributions if an event of default has occurred; redeem, repurchase, or retire equity interests or subordinated indebtedness; make certain investments; or merge, consolidate or sell substantially all of our assets. We were in compliance with these covenants as of June 30, 2016.

On June 6, 2016, we and certain of our subsidiaries, Wells Fargo Bank, National Association, as resigning trustee ("Wells Fargo") and U.S. Bank National Association, as successor trustee ("U.S. Bank"), entered into an Instrument of Resignation, Appointment and Acceptance (the "Instrument"). In connection with the Instrument, Wells Fargo resigned as trustee, note custodian, registrar and paying agent under the Indenture dated as of July 30, 2013, as supplemented and amended and we accepted such resignation and appointed U.S. Bank as the successor trustee, note custodian, registrar and paying agent under such indenture.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the 7.75% Senior Notes and the 9.25% Senior Notes and as a result, we classified $354.4 million of our outstanding amounts under the 7.75% Senior Notes, which is net of $0.3 million unamortized discount and $9.5 million deferred financing costs, and $312.1 million of our outstanding amounts under the 9.25% Senior Notes, which is net of $0.8 million unamortized discount and $8.3 million deferred financing costs, as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016. Any efforts to enforce such payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11.

On the Plan Effective Date, the 7.75% Senior Notes and the 9.25% Senior Notes (together with accrued but unpaid interest) will be cancelled and the holders will receive 90% of the common equity interests of New HoldCo (see "Restructuring Support Agreement" above).

SECURED HEDGE FACILITY

At June 30, 2016, we had a secured hedge facility agreement with a syndicate of banks under which certain Drilling Partnerships have the ability to enter into derivative contracts to manage their exposure to commodity price movements. Under our revolving credit facility, we are required to utilize this secured hedge facility for future commodity risk management activity for our equity production volumes within the participating Drilling Partnerships. We, as the ultimate general partner of the Drilling Partnerships, administer the commodity price risk management activity for the Drilling Partnerships under the secured hedge facility and guarantee their obligations under it. Before executing any hedge transaction, a participating Drilling Partnership is required to, among other things, provide mortgages on its oil and gas properties and first priority security interests in substantially all of its assets to the collateral agent for the benefit of the counterparties. The secured hedge facility agreement contains covenants that limit each of the participating Drilling Partnership's ability to incur indebtedness, grant liens, make loans or investments, make distributions if a default under the secured hedge facility agreement exists or would result from the distribution, merge into or consolidate with other persons, enter into commodity or interest rate swap agreements that do not conform to specified terms or that exceed specified amounts, or engage in certain asset dispositions including a sale of all or substantially all of its assets.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings are pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default will no longer be deemed to exist or to continue under the secured hedge facility.

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

ISSUANCE OF UNITS

We have an equity distribution agreement with Deutsche Bank Securities Inc., as representative of the several banks named therein (the "Agents"). Pursuant to the equity distribution agreement, we may sell from time to time through the Agents common units representing limited partner interests of us having an aggregate offering price of up to $100.0 million. Sales of common units may be made in negotiated transactions or transactions that are deemed to be "at-the-market" offerings as defined in Rule 415 of the Securities Act, including sales made directly on the New York Stock Exchange, the existing trading market for the common units, or sales made to or through a market maker other than on an exchange or through an electronic communications network. We pay each of the Agents a commission, which in each case shall not be more than 2.0% of the gross sales price of common units sold through such Agent. Under the terms of the equity distribution agreement, we may also sell common units from time to time to any Agent as principal for its own account at a price to be agreed upon at the time of sale. Any sale of common units to an Agent as principal would be pursuant to the terms of a separate terms agreement between us and such Agent. During the three months ended June 30, 2016, we did not issue any common limited partner units under the equity distribution program. During the six months ended June 30, 2016, we issued 245,175 common limited partner units under the equity distribution program for net proceeds of $0.2 million, net of $4,000 in commissions and offering expenses paid. During the three months ended June 30, 2015, we issued 2,403,288 common limited partner units under the equity distribution program for net proceeds of $18.0 million, net of $0.5 million in commissions and offering expenses paid. During the six months ended June 30, 2015, we issued 2,885,824 common limited partner units under the equity distribution program for net proceeds of $21.4 million, net of $0.6 million in commissions and offering expenses paid.

In August 2015, we entered into a distribution agreement with MLV & Co. LLC ("MLV"), which we terminated and replaced in November 2015, when we entered into a distribution agreement with MLV and FBR Capital Markets & Co. in which we may sell our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units ("Class D Preferred Units") and Class E Cumulative Redeemable Perpetual Preferred Units ("Class E Preferred Units"). Under both the August 2015 ATM Agreement and the November 2015 ATM Agreement, we did not issue any Class D Preferred units nor Class E Preferred Units under the preferred equity distribution program for both the three and six months ended June 30, 2016 and 2015.

In May 2015, in connection with the Arkoma Acquisition, we issued 6,500,000 of our common limited partner units in a public offering at a price of $7.97 per unit, yielding net proceeds of $49.7 million. We used a portion of the net proceeds to fund the Arkoma Acquisition and to reduce borrowings outstanding under our First Lien Credit Facility.

In April 2015, we issued 255,000 of our Class E Preferred Units at a public offering price of $25.00 per unit for net proceeds of $6.0 million.

On March 31, 2015, to partially pay our portion of a quarterly installment related to the Eagle Ford acquisition, we issued an additional 800,000 Class D Preferred Units to the seller at a value of $25.00 per unit.

On July 12, 2016, we received notification from the New York Stock Exchange (“NYSE”) that the NYSE commenced proceedings to delist our common units as a result of our failure to comply with the continued listed standards set forth in Section 802.01C of the NYSE Listed Company Manual to maintain an average closing price of $1.00 per unit over a consecutive 30 days period. Our Class D Preferred Units and Class E Preferred Units were also delisted from the NYSE. Our common units, Class D Preferred Units, and Class E Preferred Units began trading on the OTC market on July 13, 2016 with the ticker symbol “ARPJ” for our common units, “ARPJP” for our Class D Preferred Units, and “ARPJN” for our Class E Preferred Units.

On May 12, 2016, due to the income tax ramifications of the potential options we were considering, the Board of Directors delayed the vesting date of approximately 110,000 units granted to employees, directors and officers until March 2017. The phantom units were set to vest between May 15, 2016 and August 31, 2016. The delayed vesting schedule did not have a significant impact on the compensation expense recorded in general and administrative expenses on the condensed consolidated statement of operations for the three and six months ended June 30, 2016 or our remaining unrecognized compensation expense related to such awards.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Recently Issued Accounting Standards

See Notes 2 and 5 to our condensed consolidated financial statements for additional information related to recently issued accounting standards.

For a more complete discussion of the accounting policies and estimates that we have identified as critical in the preparation of our condensed consolidated financial statements, please refer to our Management’s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

General

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

We are exposed to various market risks, principally fluctuating interest rates and changes in commodity prices. These risks can impact our results of operations, cash flows and financial position. We manage these risks through regular operating and financing activities and periodic use of derivative financial instruments such as forward contracts and interest rate cap and swap agreements. The following analysis presents the effect on our results of operations, cash flows and financial position as if the hypothetical changes in market risk factors occurred on June 30, 2016. Only the potential impact of hypothetical assumptions was analyzed. The analysis does not consider other possible effects that could impact our business.

We are subject to the risk of loss on our derivative instruments that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We maintain credit policies with regard to our counterparties to minimize our overall credit risk. These policies require (i) the evaluation of potential counterparties' financial condition to determine their credit worthiness; (ii) the quarterly monitoring of our oil, natural gas and NGLs counterparties' credit exposures; (iii) comprehensive credit reviews on significant counterparties from physical and financial transactions on an ongoing basis; (iv) the utilization of contractual language that affords us netting or set off opportunities to mitigate exposure risk; and (v) when appropriate requiring counterparties to post cash collateral, parent guarantees or letters of credit to minimize credit risk. Our assets related to derivatives as of June 30, 2016 represent financial instruments from ten counterparties; all of which are financial institutions that have an "investment grade" (minimum Standard & Poor's rating of BBB+ or better) credit rating and are lenders associated with our revolving credit facility. Subject to the terms of our revolving credit facility, collateral or other securities are not exchanged in relation to derivatives activities with the parties in the revolving credit facility.

Interest Rate Risk. At June 30, 2016, $669.5 million was outstanding under our revolving credit facility and $244.5 million was outstanding under our term loan facility. Holding all other variables constant, a hypothetical 100 basis-point or 1% change in variable interest rates would change our consolidated interest expense for the twelve-month period ending June 30, 2017 by approximately $9.2 million.

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

Holding all other variables constant, including the effect of commodity derivatives, a 10% change in average commodity prices would result in a change to our consolidated operating income for the twelve-month period ending June 30, 2017 of approximately $5.6 million.

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

At June 30, 2016, we had the following commodity derivatives:

Type	Production Period Ending December 31,	Volumes[1]	Average Fixed Price[1]
Natural Gas – Fixed Price Swaps	2016[2]	26,910,000	$ 4.224
	2017	50,120,000	$ 4.221
	2018	40,300,000	$ 4.168
	2019	15,860,000	$ 4.019
Natural Gas – Put Options – Drilling Partnerships	2016[2]	720,000	$ 4.150
Crude Oil – Fixed Price Swaps	2016[2]	820,500	$ 81.685
	2017	1,200,000	$ 77.610
	2018	1,080,000	$ 76.281
	2019	540,000	$ 68.371

(1) Volumes for natural gas are stated in million British Thermal Units. Volumes for crude oil are stated in barrels.
(2) The production volumes for 2016 include the remaining six months of 2016 beginning July 1, 2016.

ITEM 4: CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

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

Under the supervision of our Chief Executive Officer and Chief Financial Officer and with the participation of our disclosure committee appointed by such officers, we have carried out an evaluation of the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that, as of June 30, 2016, our disclosure controls and procedures were effective at the reasonable assurance level.

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

PART II

ITEM 1A: RISK FACTORS

There have been no material changes to the Risk Factors disclosed in Part I – Item 1A "–Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2015 except as follows.

We are subject to risks and uncertainties related to Chapter 11 cases.

We have filed voluntary petitions for relief under the Bankruptcy Code and are subject to the risks and uncertainties associated with bankruptcy cases. These risks include the following:

- our ability to continue as a going concern;
- our ability to obtain final Bankruptcy Court approval with respect to motions filed in the Chapter 11 proceedings from time to time;
- whether the conditions to confirm and consummate the proposed Plan outlined in the Restructuring Support Agreement will be satisfied or waived;
- the ability of third parties to seek and obtain court approval to terminate or shorten the exclusivity period for us to propose and confirm a plan of reorganization, to appoint a United States Trustee, or to convert the Chapter 11 cases to Chapter 7 cases;
- our ability to retain key vendors or secure alternative supply sources;
- our ability to fund and execute our business plan;
- our ability to obtain and maintain normal payment and other terms with vendors and service providers;
- our ability to maintain contracts that are critical to our operations;
- our ability to attract, motivate, and retain management;
- significant time and effort required to be spent by our senior management in dealing with the Chapter 11 cases;
- negative effects and increased costs of a prolonged duration of the Chapter 11 cases; and
- the high costs of bankruptcy proceedings and related fees.

Delays in our Chapter 11 cases increase the risks of us being unable to reorganize our business and emerge from bankruptcy in the manner contemplated by us, or at all, and may increase our costs associated with the bankruptcy process.

These risks and uncertainties could affect our business and operations in various ways. For example, negative events or publicity associated with our Chapter 11 proceedings could adversely affect our relationships with our suppliers, service providers, customers, employees, and other third parties, which in turn could adversely affect our operations and financial condition. Also, pursuant to the United States Bankruptcy Code (the "Bankruptcy Code"), we need the prior approval of the Bankruptcy Court for transactions outside the ordinary course of business, which may limit our ability to respond timely to certain events or take advantage of certain opportunities. Because of the risks and uncertainties associated with our Chapter 11 cases, we cannot accurately predict or quantify the ultimate impact that events that occur during our Chapter 11 cases will have on our business, financial condition, cash flows, liquidity, results of operations.

The Restructuring Support Agreement is subject to significant conditions and milestones that are beyond our control. If the Restructuring Support Agreement is terminated, our ability to confirm and consummate the Plan could be materially and adversely affected.

The Restructuring Support Agreement sets forth certain conditions we must satisfy, including the timely satisfaction of milestones in the Chapter 11 proceeding, such as confirmation and substantial consummation of the Plan. Our ability to timely complete such milestones is subject to risks and uncertainties that may be beyond our control. The Restructuring Support Agreement gives certain of our stakeholders the ability to terminate the Restructuring Support Agreement under certain circumstances, including the failure of certain conditions to be satisfied. Should a termination event occur, all obligations of the parties to the Restructuring Support Agreement will terminate, except that any party’s termination solely with respect to itself will not result in the termination of the Restructuring Support Agreement with respect to any other party. A termination of the Restructuring Support Agreement may result in the loss of support for the Plan, which could adversely affect our ability to confirm and consummate the Plan. If the Plan is not consummated, there can be no assurance that any alternate plan of reorganization would be as favorable to holders of claims as the current Plan and our Chapter 11 proceedings could become protracted, which could significantly and detrimentally impact our relationships with vendors, suppliers, employees, and customers.

We may not be able to obtain confirmation of the Plan.

There can be no assurance that the Plan will be confirmed by the Bankruptcy Court. We might receive official objections to confirmation of the Plan from the various committees and stakeholders in the Chapter 11 proceedings. We cannot predict the impact that any objection might have on the Plan or on a Bankruptcy Court’s decision to confirm the Plan. Any objection may cause us to devote significant resources in response which could materially and adversely affect our business, financial condition and results of operations.

While certain of our stakeholders have agreed to support the Plan under the Restructuring Support Agreement, if we are unable to implement the Plan, any alternative plan of reorganization will also require the willingness of certain stakeholders to agree to the exchange or modification of their interests. There can be no guarantee of success with respect to the Plan or any other plan of reorganization. If the Plan is not confirmed by the Bankruptcy Court, it is unclear whether we would be able to reorganize our business and what, if any, distributions holders of claims against us would ultimately receive with respect to their claims. There can be no assurance as to whether we will successfully reorganize and emerge from Chapter 11 or, if we do successfully reorganize, as to when we would emerge from Chapter 11. If no plan of reorganization can be confirmed, or if the Bankruptcy Court otherwise finds that it would be in the best interest of holders of claims and interests, the Chapter 11 cases may be converted to cases under Chapter 7 of the Bankruptcy Code, pursuant to which a trustee would be appointed or elected to liquidate our assets for distribution in accordance with the priorities established by the Bankruptcy Code.

Even if a Chapter 11 plan of reorganization is consummated, we may not be able to achieve our stated goals and continue as a going concern.

Even if the Plan or another Chapter 11 plan of reorganization is consummated, we will continue to face a number of risks, including further deterioration in commodity prices or other changes in economic conditions, changes in our industry, changes in demand for our oil and gas and increasing expenses. Accordingly, we cannot guarantee that the Plan or any other plan of reorganization will achieve our stated goals.

Furthermore, even if our debts are reduced or discharged through the Plan, we may need to raise additional funds through public or private debt or equity financing or other various means to fund our business after the completion of our Chapter 11 proceedings. Our access to additional financing is, and for the foreseeable future will likely continue to be, extremely limited, if it is available at all.

Our ability to continue as a going concern is dependent upon our ability to raise additional capital. As a result, we cannot give any assurance of our ability to continue as a going concern, even if the Plan is confirmed.

Under the Plan, holders of the our limited partnership units will receive no recovery.

On the Plan Effective Date, all of our preferred limited partnership units and common limited partnership units will be cancelled. Holders of units as of the Plan Effective Date will receive no cash payment or other consideration.

Holders of our units (including anyone who purchases units being sold by other unitholders) will have a cash tax liability that could be substantial. Our units will be cancelled pursuant to the Plan without the receipt of any consideration. As a result, upon consummation of the Plan, holders and purchasers will have a resulting cash tax liability that will be significantly in excess of their economic return with respect to our units. Existing holders and prospective purchasers of our units should consult their tax advisors before deciding whether to continue to hold, or purchase, any units and ensure sufficient time for sales of units to be processed by their brokers and to settle prior to the Plan Effective Date.

Atlas will recognize cancellation of indebtedness ("COD") income and other amounts of income (including, for example, income resulting from the sale or our hedge portfolio) as a result of the transactions contemplated by the Plan, which could be substantial. Items of income, gain, loss, and deduction attributable to the consummation of the transactions under the Plan will be allocated to our unitholders of record as of the Plan Effective Date. As a result, our existing unitholders who continue to hold units through the consummation of the Plan and any prospective purchasers of our limited partner units, as a result of purchasing such units (including the purchase of units being sold by other unitholders), should be aware that they will receive an allocation of taxable income, which could be substantial, as a result of the consummation of the Plan for which there will not be any corresponding cash distribution. Our unitholders are not entitled to any recovery pursuant to the Plan and all of our units will be cancelled without the receipt of any consideration. As a result, upon consummation of the Plan, holders and purchasers will have a resulting cash tax liability that will be significantly in excess of their economic return with respect to their units.

Each unitholder's tax situation is different. The ultimate effect to each unitholder will depend on the unitholder's individual tax position with respect to its units. Additionally, even if a unitholder may have tax attributes available to offset some or all of the COD income and other income that will be generated as a result of the consummation of the Plan, those attributes may not be sufficient to offset the COD income and other income allocated to them as a result of the Plan. In particular, a unitholder who has recently acquired its units is generally expected to have little or no offsetting tax attributes, while such holder would still be allocated its full pro rata share of any COD income and any income from the sale of the hedges.

Unitholders should also be aware that the disclosure of the information contained in ARP's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 25, 2016 may result in significant sales of units by existing unitholders. Sales of units or the perception that such sales could occur, including potential sales by holders of Notes that also hold units, could adversely affect the price of the units. There can be no assurances as to whether, or at what price, a unitholder (including any prospective purchaser of units who purchases but then wishes to sell its units) may be able to sell its units.

Existing unitholders and prospective unitholders are highly encouraged to carefully review the section entitled "—Certain United States Federal Income Tax Consequences — Consequences of the Plan to Holders of ARP Equity Interests" in the Disclosure Statement, which was filed as an exhibit to ARP's Current Report on Form 8-K with the Securities and Exchange Commission on July 25, 2016, and to consult and depend on their own tax advisors prior to purchasing any of our units or deciding whether to retain or sell existing units, including as to the tax consequences of the purchase or sale itself.

Allocations of COD income and other amounts of income, gain, loss and deduction attributable to the consummation of the transactions under the Plan will be allocated to our unitholders of record as of the Plan Effective Date. No COD income or other amounts of income, gain, or loss related to the consummation of the Plan should be allocated to a unitholder with respect to units which are sold and settled before that date. Unitholders wishing to sell units before such allocations are made are highly encouraged to consult their brokers as soon as possible to make appropriate arrangements to ensure that there is sufficient time for their brokers to process such sales, and for such sales to settle, no later than the business day prior to the Plan Effective Date. Atlas expects to publicly announce the Plan Effective Date at such time that it is known, however, there can be no assurance that there will be sufficient time between such announcement and the Plan Effective Date for sales of units to be processed and settle.

Our long term liquidity requirements and the adequacy of our capital resources are difficult to predict at this time.

We face uncertainty regarding the adequacy of our liquidity and capital resources and have extremely limited, if any, access to additional financing. In addition to the cash requirements necessary to fund our ongoing operations, we have incurred significant fees and other costs in connection with our Chapter 11 proceedings and expect to continue to incur significant fees and costs throughout our Chapter 11 proceedings. We cannot assure you that our cash on hand and cash flow from operations will be sufficient to continue to fund our operations and allow us to satisfy our obligations related to the Chapter 11 proceedings until we are able to emerge from our Chapter 11 proceedings.

Our financial results may be volatile and may not reflect historical trends.

During the Chapter 11 proceedings, we expect our financial results to continue to be volatile as asset impairments, asset dispositions, restructuring activities and expenses, contract terminations and rejections, and claims assessments may significantly impact our consolidated financial performance. As a result, our historical financial performance is likely not indicative of our financial performance following the commencement of the Chapter 11 proceedings.

In addition, if we emerge from Chapter 11, the amounts reported in subsequent consolidated financial statements may materially change relative to historical consolidated financial statements, including as a result of revisions to our operating plans pursuant to a

plan of reorganization. We also may be required to adopt fresh start accounting, in which case our assets and liabilities will be recorded at fair value as of the fresh start reporting date, which may differ materially from the recorded values of assets and liabilities on our consolidated balance sheets. Our financial results after the application of fresh start accounting also may be different from historical trends.

The Chapter 11 proceedings will consume a substantial portion of the time and attention of our management, which may have an adverse effect on our business and results of operations, and we may face increased levels of employee attrition.

Although the Restructuring Support Agreement and the Plan are designed to minimize the length of our Chapter 11 proceedings, it is impossible to predict with certainty the amount of time that we may spend in bankruptcy or to assure parties in interest that the Plan will be confirmed. The Chapter 11 proceedings will involve additional expense and our management will be required to spend a significant amount of time and effort focusing on the proceedings. This diversion of attention may materially adversely affect the conduct of our business, and, as a result, our financial condition and results of operations, particularly if the Chapter 11 proceedings are protracted.

During the pendency of the Chapter 11 proceedings, our employees will face considerable distraction and uncertainty and we may experience increased levels of employee attrition. A loss of key personnel or material erosion of employee morale could have a material adverse effect on our ability to effectively, efficiently and safely conduct our business, and could impair our ability to execute our strategy and implement operational initiatives, thereby having a material adverse effect on our financial condition and results of operations.

We may be subject to claims that will not be discharged in our Chapter 11 proceedings, which could have a material adverse effect on our financial condition and results of operations.

The Bankruptcy Code provides that the confirmation of a Chapter 11 plan of reorganization discharges a debtor from substantially all debts arising prior to the commencement of the Chapter 11 cases. However, certain claims will not be "impaired" as part of the Chapter 11 cases and therefore may not be discharged in accordance with the Bankruptcy Code and the terms of the plan of reorganization upon our emergence from bankruptcy. Any claims not ultimately discharged through a Chapter 11 plan of reorganization could be asserted against the reorganized entities and may have an adverse effect on our financial condition and results of operations on a post-reorganization basis.

Any plan of reorganization that we may implement will be based in large part upon assumptions and analyses developed by us. If these assumptions and analyses prove to be incorrect, our plan may be unsuccessful in its execution.

Any plan of reorganization that we may implement, including the Plan, will likely affect both our capital structure and the ownership, structure and operation of our businesses and will reflect assumptions and analyses based on our experience and perception of historical trends, current conditions and expected future developments, as well as other factors that we consider appropriate under the circumstances. Whether actual future results and developments will be consistent with our expectations and assumptions depends on a number of factors, including but not limited to (i) our ability to change substantially our capital structure; (ii) our ability to obtain adequate liquidity and financing sources; (iii) our ability to maintain customers' confidence in our viability as a continuing entity and to attract and retain sufficient business from them; (iv) our ability to retain key employees, and (v) the overall strength and stability of general economic conditions of the financial and oil and gas industries, both in the U.S. and in global markets. The failure of any of these factors could materially adversely affect the successful reorganization of our businesses.

In addition, any plan of reorganization will rely upon financial projections, including with respect to revenues, EBITDA, capital expenditures, debt service and cash flow. Financial forecasts are necessarily speculative, and it is likely that one or more of the assumptions and estimates that are the basis of these financial forecasts will not be accurate. In our case, the forecasts will be even more speculative than normal, because they will likely involve fundamental changes in the nature of our capital structure. Accordingly, we expect that our actual financial condition and results of operations will differ, perhaps materially, from what we have anticipated. Consequently, there can be no assurance that the results or developments contemplated by any plan of reorganization we may implement will occur or, even if they do occur, that they will have the anticipated effects on us and our subsidiaries or our businesses or operations. The failure of any such results or developments to materialize as anticipated could materially adversely affect the successful execution of any plan of reorganization.

For the duration of the Chapter 11 proceedings, we may not be able to enter into commodity derivatives covering estimated future production on favorable terms.

During the Chapter 11 proceedings, our ability to enter into new commodity derivatives covering estimated future production will be dependent upon either entering into unsecured hedges or obtaining Bankruptcy Court approval to enter into secured hedges. As a result, we may not be able to enter into additional commodity derivatives covering production in future periods on favorable terms or at all. If we cannot or choose not to enter into commodity derivatives in the future, we could be more affected by changes in commodity prices than competitors who engage in hedging arrangements. Our inability to hedge the risk of low commodity prices in the future, on favorable terms or at all, could have a material adverse impact on our business, financial condition and results of operations.

In certain instances, a Chapter 11 case may be converted to a case under Chapter 7 of the Bankruptcy Code.

Upon a showing of cause, the Bankruptcy Court may convert our Chapter 11 case to a case under Chapter 7 of the Bankruptcy Code. In such event, a Chapter 7 trustee would be appointed or elected to liquidate our assets for distribution in accordance with the priorities established by the Bankruptcy Code. We believe that liquidation under Chapter 7 would result in significantly smaller distributions being made to our creditors than those provided for in our Plan because of (i) the likelihood that the assets would have to be sold or otherwise disposed of in a distressed fashion over a short period of time rather than in a controlled manner and as a going concern, (ii) additional administrative expenses involved in the appointment of a Chapter 7 trustee, and (iii) additional expenses and claims, some of which would be entitled to priority, that would be generated during the liquidation and from the rejection of leases and other executory contracts in connection with a cessation of operations.

ITEM 3: DEFAULTS UPON SENIOR SECURITIES

On June 16, 2016, our Board of Directors elected to suspend our 8.625% Class D Cumulative Redeemable Perpetual Preferred Units and 10.75% Class E Cumulative Redeemable Perpetual Preferred Units distributions, beginning with the second quarter 2016 distribution, due to the continued lower commodity price environment.

As of July 15, 2016, the cumulative unpaid dividends on the 8.625% Class D Cumulative Redeemable Perpetual Preferred Units and 10.75% Class E Cumulative Redeemable Perpetual Preferred Units, were $2.2 million and $0.2 million, respectively.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the First Lien Credit Facility and as a result, we classified $669.5 million of our outstanding amounts under the First Lien Credit Facility as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the Second Lien Term Loan and as a result, we classified $244.5 million of our outstanding amounts under the Second Lien Term Loan, which is net of $5.5 million unamortized discount and $9.4 million deferred financing costs, as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016.

Our Chapter 11 Filings constituted an event of default that accelerated our obligations under the 7.75% Senior Notes and the 9.25% Senior Notes and as a result, we classified $354.4 million of our outstanding amounts under the 7.75% Senior Notes, which is net of $0.3 million unamortized discount and $9.5 million deferred financing costs, and $312.1 million of our outstanding amounts under the 9.25% Senior Notes, which is net of $0.8 million unamortized discount and $8.3 million deferred financing costs, as current portion of long-term debt within our condensed consolidated balance sheet as of June 30, 2016.

Any efforts to enforce these payments are automatically stayed as a result of the Chapter 11 Filings, and the holders' rights of enforcement are subject to the applicable provisions of Chapter 11.

An event of default occurred under the secured hedging facility agreement upon our filing of voluntary petitions for relief under Chapter 11. The lenders under the secured hedge facility agreed to forbear from exercising remedies in respect of such event of default while the Chapter 11 Filings are pending and, upon occurrence of the effective date of the Plan contemplated by the Restructuring Support Agreement, such event of default will no longer be deemed to exist or to continue under the secured hedge facility.

ITEM 6: EXHIBITS

4.1	Instrument of Resignation, Appointment and Acceptance, dated as of June 6, 2016, by and among Atlas Resource Partners Holdings, LLC, Atlas Resource Finance Corporation, Atlas Resource Partners, L.P., the Subsidiary Guarantors named therein, Wells Fargo Bank, National Association and U.S. Bank National Association(1)
10.1	Restructuring Support Agreement dated July 25, 2016(2)
31.1	Rule 13(a)-14(a)/15(d)-14(a) Certification
31.2	Rule 13(a)-14(a)/15(d)-14(a) Certification

32.1	Section 1350 Certification
32.2	Section 1350 Certification
101.INS	XBRL Instance Document(3)
101.SCH	XBRL Schema Document(3)
101.CAL	XBRL Calculation Linkbase Document(3)
101.LAB	XBRL Label Linkbase Document(3)
101.PRE	XBRL Presentation Linkbase Document(3)

101.DEF XBRL Definition Linkbase Document[(3)]

(1) Previously filed as an exhibit to our Current Report on Form 8-K filed on June 7, 2016.
(2) Previously filed as an exhibit to our Current Report on Form 8-K filed on July 25, 2016.
(3) Attached as Exhibit 101 to this report are documents formatted in XBRL (Extensible Business Reporting Language). The financial information contained in the XBRL-related documents is “unaudited” or “unreviewed”.

SIGNATURES

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

ATLAS RESOURCE PARTNERS, L.P.
By: Atlas Energy Group, LLC, its General Partner

Date: August 8, 2016	By:	/s/ DANIEL C. HERZ Daniel C. Herz Chief Executive Officer of ARP
Date: August 8, 2016	By:	/s/ JEFFREY M. SLOTTERBACK Jeffrey M. Slotterback Chief Financial Officer of ARP
Date: August 8, 2016	By:	/s/ MATTHEW J. FINKBEINER Matthew J. Finkbeiner Chief Accounting Officer of ARP