Atlas Resource Partners, L.P. Reports Operating And Financial Results For The Third Quarter 2015

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- **Adjusted EBITDA was $68.1 million(1) and Distributable Cash Flow was $28.8 million(1) for the third quarter 2015**
- **Gas and oil production costs continued to benefit from effective cost-reduction initiatives, decreasing 22% from the comparable prior year quarter**
- **Natural gas and oil production in the third quarter 2015 were hedged approximately 71% and 100%, respectively; ARP's current market value of its hedge portfolio is approximately $360 million**
- **Management will discuss third quarter 2015 financial and operational results on a conference call at 9:00 AM ET on Tuesday, November 10th**

Atlas Resource Partners, L.P. (NYSE: ARP) ("ARP" or "the Company") reported operating and financial results for the third quarter 2015.

Daniel Herz, Chief Executive Officer of ARP, stated, "The current state of the energy industry has presented a challenging environment, however our business continues to exhibit its solid foundation, including stable producing assets, a strong hedge position through 2019 and fees from our investment partnership business. In addition, our company has continued to make meaningful progress in reducing production costs and capital spending, which we believe is crucial to preserving value during these periods. All of our efforts are ultimately focused on positioning the company to withstand the current markets and expand our businesses as we have in the past."

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- Third quarter 2015 Adjusted EBITDA, a non-GAAP measure, was $68.1 million(1), compared to $64.7 million for the second quarter 2015. The increase from the second quarter 2015 was due to higher fee income from ARP's partnership management business, partially offset by higher general and administrative expenses related to the timing of fundraising activities from the current year investment program.
- Distributable Cash Flow, a non-GAAP measure, was $28.8 million(1), or approximately $0.29 per common unit, for the third quarter 2015, compared with $25.4 million, or approximately $0.27 per common unit, for the second quarter 2015. The increase was primarily due to similar factors as noted above.
- ARP paid monthly cash distributions totaling $0.325 per common limited partner unit for the third quarter 2015 at a distribution coverage ratio of approximately 0.9x. On October 28, 2015, ARP announced the September 2015 monthly distribution of $0.1083 per common unit ($1.30 per unit on an annualized basis), which will be paid on November 13, 2015 to unitholders of record as of November 9, 2015.
- On a GAAP basis, net loss was $560.9 million for the third quarter 2015, compared with a loss of $46.8 million for the second quarter 2015 and net income of $1.9 million in the prior year third quarter. Net loss in the current period was principally due to non-cash expenses, specifically an asset impairment charge on certain oil and gas properties due to recent declines in forward commodity prices, partially offset by the mark-to-market gains recognized in the current quarter from ARP's financial hedge positions.

Operating Results

- Average net daily production for the third quarter 2015 was 264.2 million cubic feet equivalents per day ("Mmcfed"), as compared to 270.8 Mmcfed for the second quarter 2015. ARP's third quarter 2015 production was comprised of 82% natural gas, 11% oil and 7% natural gas liquids ("NGL"). The Company connected two Mississippi Lime wells during the third quarter, and now operates 27 wells in the Eagle Ford shale. ARP is currently connecting additional wells on its Eagle Ford position and expects oil volumes to increase into 2016 as a result of its activity.

- ARP's net realized price for natural gas including the effect of hedge positions was $3.30 per thousand cubic feet ("mcf") for the third quarter 2015, compared to $3.33/mcf for the second quarter 2015. Net realized oil prices including the effect of hedge positions averaged $88.42 per barrel ("bbl") for the third quarter 2015, compared to $83.19/bbl for the second quarter 2015. The Company was hedged approximately 71% on its natural gas production and approximately 100% on its oil production in the third quarter 2015.
- Lease operating expenses decreased 6% from the second quarter 2015 to $1.30/mcf, and overall production costs of $1.74/mcf in the third quarter 2015 were 22% lower than the prior year comparable quarter. The decrease in expenses is due to the Company's ongoing production cost-reduction efforts, namely focused on water disposal, compression and fuel costs.
- Investment partnership margin was approximately $12.0 million in the third quarter 2015, compared with $6.7 million for the second quarter 2015. The increase in investment partnership margin was due to increased deployment of partnership capital during the current quarter, which generated higher fee income, specifically Administration and Oversight Fees realized from the drilling of new investment program wells.

Hedge Positions

- ARP's hedge portfolio is comprised entirely of fixed-price swap and costless collar positions through 2019, and is valued at approximately $360 million as of November 9, 2015.
- The Company's oil production is hedged approximately 88%, 64%, 61% and 30% based on third quarter 2015 average production for the years 2016 through 2019, respectively, at an average price of approximately $76/bbl. ARP's natural gas production is hedged 68%, 63% and 52% for 2016, 2017 and 2018, respectively, based on third quarter 2015 production at an average price of approximately $4.20/mcf, with additional hedges in 2019. A summary of ARP's derivative positions as of November 9, 2015 is provided in the financial tables of this release.

Corporate Expenses & Capital Position

- Cash general and administrative expense was $12.5 million for the third quarter 2015, compared to $10.7 million for the second quarter 2015. The increase from the prior period was primarily due to timing of activity related to the Company's partnership activities, and other seasonal corporate expenses.
- Cash interest expense was $21.5 million for the third quarter 2015, compared with $21.2 million for the second quarter 2015 and $14.1 million for the prior year comparable quarter. The increase compared to the prior year third quarter was due to the follow-on offering of $75 million of 9.25% Senior Notes due 2021 in October 2014 to partially fund ARP's acquisitions of oil producing properties in the Rangely Field and the Eagle Ford Shale, as well as the $250 million second lien financing entered into by ARP in February 2015.
- At September 30, 2015, ARP had approximately $1.5 billion of total debt outstanding, which was consistent with the balance at June 30, 2015. The outstanding debt balance included $563.4 million borrowed under its revolving credit facility with a borrowing base of $750 million.

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ARP will be discussing its third quarter 2015 results on an investor call with management on Tuesday, November 10, 2015 at 9:00 a.m. Eastern Time. Interested parties are invited to access the live webcast the investor call by going to the *Investor Relations* section of Atlas Resource's website at www.atlasresourcepartners.com. For those unavailable to listen to the live broadcast, the replay of the webcast will be available following the live call on the ARP website and telephonically beginning at approximately 1:00 p.m. ET on November 10, 2015 by dialing (855) 859-2056, passcode: 66843641.

Atlas Resource Partners, L.P. (NYSE: ARP) is an exploration & production master limited partnership which owns an interest in over 14,500 producing natural gas and oil wells, located primarily in Appalachia, the Eagle Ford Shale (TX), the Barnett Shale (TX), the Mississippi Lime (OK), the Raton Basin (NM), Black Warrior Basin (AL), Arkoma Basin (OK) and the Rangely Field in Colorado. ARP is also the largest sponsor of natural gas and oil investment partnerships in the U.S. For more information, please visit our website at www.atlasresourcepartners.com, or contact Investor Relations at InvestorRelations@atlasenergy.com.

Atlas Energy Group, LLC (NYSE: ATLS) is a limited liability company which owns the following interests: all of the general partner interest, incentive distribution rights and an approximate 23% limited partner interest in its upstream oil & gas subsidiary, Atlas Resource Partners, L.P.; the general partner interests, incentive distribution rights and limited partner interests in Atlas Growth Partners, L.P.; and a general partner interest in Lightfoot Capital Partners, an entity that invests directly in energy-related businesses and assets. For more information, please visit our website at www.atlasenergy.com, or contact Investor Relations at InvestorRelations@atlasenergy.com.

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Cautionary Note Regarding Forward-Looking Statements

Certain matters discussed within this press release are forward-looking statements. Although Atlas Resource Partners, L.P. believes the expectations reflected in such forward-looking statements are based on reasonable assumptions, it can give no assurance that its expectations will be attained. Atlas Resource Partners does not undertake any duty to update any statements contained herein (including any forward-looking statements), except as required by law. This document contains forward-looking statements that involve a number of assumptions, risks and uncertainties that could cause actual results to differ materially from those contained in the forward-looking statements. ARP cautions readers that any forward-looking information is not a guarantee of future performance. Such forward-looking statements include, but are not limited to, statements about future financial and operating results, resource potential, ARP's plans, objectives, expectations and intentions and other statements that are not historical facts. Risks, assumptions and uncertainties that could cause actual results to materially differ from the forward-looking statements include, but are not limited to, those associated with general economic and business conditions; ARP's ability to realize the benefits of its acquisitions; changes in commodity prices; changes in the costs and results of drilling operations; uncertainties about estimates of reserves and resource potential; inability to obtain capital needed for operations; ARP's level of indebtedness; changes in government environmental policies and other environmental risks; the availability of drilling equipment and the timing of production; tax consequences of business transactions; and other risks, assumptions and uncertainties detailed from time to time in ARP's reports filed with the U.S. Securities and Exchange Commission, including quarterly reports on Form 10-Q, current reports on Form 8-K and annual reports on Form 10-K. Forward-looking statements speak only as of the date hereof, and ARP assumes no obligation to update such statements, except as may be required by applicable law.

(1) A reconciliation of GAAP net income (loss) to Adjusted EBITDA and Distributable Cash Flow is provided in the financial tables of this release. Please see footnote 61 to the Financial Information table of this release.

ATLAS RESOURCE PARTNERS, L.P.
CONSOLIDATED STATEMENTS OF OPERATIONS
(unaudited; in thousands, except per unit data)

	Three Months Ended September 30,		Nine Months Ended September 30	
	2015	**2014**	**2015**	**2014**
Revenues:				

Gas and oil production	$ 90,734	$ 129,399	$ 292,243	$ 337,893
Well construction and completion	23,054	61,204	63,665	126,917
Gathering and processing	1,685	3,061	6,046	11,287
Administration and oversight	5,495	6,177	7,301	12,072
Well services	5,842	6,597	18,568	18,441
Gain on mark-to-market derivatives	131,065	—	209,706	—
Other, net	20	261	80	343
Total revenues	257,895	206,699	597,609	506,953
Costs and expenses:				
Gas and oil production	41,591	51,391	130,224	133,038
Well construction and completion	20,046	53,221	55,361	110,363
Gathering and processing	2,473	3,214	7,406	11,900
Well services	2,398	2,617	6,735	7,525
General and administrative	13,978	13,124	44,400	50,894
Depreciation, depletion and amortization	40,463	64,578	125,948	176,077
Asset impairment	672,246	—	672,246	—
Total costs and expenses	793,195	188,145	1,042,320	489,797
Operating income (loss)	(535,300)	18,554	(444,711)	17,156
Loss on asset sales and disposal	(362)	(92)	(276)	(1,686)
Interest expense	(25,192)	(16,577)	(75,105)	(43,028)
Net income (loss)	(560,854)	1,885	(520,092)	(27,558)
Preferred limited partner dividends	(4,293)	(4,475)	(12,180)	(13,298)
Net loss attributable to common limited partners and the general partner	$ (565,147)	$ (2,590)	$ (532,272)	$ (40,856)
Allocation of net loss attributable to common limited partners and the general partner:				
General partner's interest	$ (11,303)	$ 3,009	$ (10,645)	$ 7,427
Common limited partners' interest	(553,844)	(5,599)	(521,627)	(48,283)
Net loss attributable to common limited partners and the general partner	$ (565,147)	$ (2,590)	$ (532,272)	$ (40,856)
Net loss attributable to common limited partners per unit:				
Basic	$ (5.73)	$ (0.07)	$ (5.74)	$ (0.67)
Diluted	$ (5.73)	$ (0.07)	$ (5.74)	$ (0.67)
Weighted average common limited partner units outstanding:				
Basic	96,660	81,521	90,943	72,288
Diluted	96,660	81,521	90,943	72,288

ATLAS RESOURCE PARTNERS, L.P.
CONSOLIDATED BALANCE SHEETS
(unaudited; in thousands)

ASSETS	September 30, 2015	December 31, 2014
Current assets:		
Cash and cash equivalents	$ 2,418	$ 15,247
Accounts receivable	89,402	114,520
Advances to affiliates	1,178	—
Current portion of derivative asset	146,622	144,259
Subscriptions receivable	23,054	32,398
Prepaid expenses and other	25,407	26,296
Total current assets	288,081	332,720
Property, plant and equipment, net	1,534,718	2,263,820
Goodwill and intangible assets, net	14,154	14,330
Long-term derivative asset	205,979	130,602
Other assets, net	53,826	50,081
	$ 2,096,758	$ 2,791,553

LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities:		
Accounts payable	$ 82,209	$ 111,198
Advances from affiliates	—	2,249
Liabilities associated with drilling contracts	—	40,611
Accrued well drilling and completion costs	56,300	80,404
Distribution payable	14,234	20,876
Accrued liabilities	77,002	84,235
Total current liabilities	229,745	339,573
Long-term debt	1,505,047	1,394,460
Asset retirement obligations and other	117,089	109,983
Commitments and contingencies		
Partners' Capital:		
General partner's interest	(27,465)	(13,697)
Preferred limited partners' interests	188,910	163,522
Common limited partners' interests	35,854	605,065
Class C common limited partner warrants	1,176	1,176
Accumulated other comprehensive income	46,402	191,471
Total partners' capital	244,877	947,537
	$ 2,096,758	$ 2,791,553

ATLAS RESOURCE PARTNERS, L.P
Financial and Operating Highlights
(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net loss attributable to common limited partners per unit - basic	$ (5.73)	$ (0.07)	$ (5.74)	$ (0.67)
Cash distributions paid per unit[1]	$ 0.325	$ 0.590	$ 0.975	$ 1.753
Production revenues (in thousands):				
Natural gas	$ 57,919	$ 79,251	$ 181,008	$ 239,233
Oil	28,854	38,151	97,100	67,626
Natural gas liquids	3,961	11,997	14,135	31,034
Total production revenues	$ 90,734	$ 129,399	$ 292,243	$ 337,893
Production volume:[2][3]				
Appalachia: [4]				
Natural gas (Mcfd)	33,950	38,218	32,522	39,083
Oil (Bpd)	326	367	343	390
Natural gas liquids (Bpd)	30	46	34	40
Total (Mcfed)	36,087	40,693	34,782	41,661
Coal-bed Methane: [4]				
Natural gas (Mcfd)	128,560	140,177	131,314	130,393
Oil (Bpd)	—	—	—	—
Natural gas liquids (Bpd)	—	—	—	—
Total (Mcfed)	128,560	140,177	131,314	130,393
Barnett/Marble Falls:				
Natural gas (Mcfd)	43,685	57,726	46,868	58,445
Oil (Bpd)	495	1,273	625	1,114
Natural gas liquids (Bpd)	1,898	2,861	2,088	2,732
Total (Mcfed)	58,043	82,535	63,144	81,523
Rangely/Eagle Ford: [4][5]				
Natural gas (Mcfd)	313	—	337	—
Oil (Bpd)	3,573	2,567	3,790	865
Natural gas liquids (Bpd)	313	263	324	89
Total (Mcfed)	23,631	16,978	25,024	5,721
Mississippi Lime/Hunton:				
Natural gas (Mcfd)	6,763	6,679	6,921	6,295
Oil (Bpd)	433	366	443	368
Natural gas liquids (Bpd)	569	545	572	524
Total (Mcfed)	12,771	12,145	13,014	11,651
Other Operating Areas:[4]				
Natural gas (Mcfd)	3,143	3,195	3,197	3,287
Oil (Bpd)	16	25	19	24
Natural gas liquids (Bpd)	311	334	248	337
Total (Mcfed)	5,104	5,349	4,799	5,453
Total Production:				
Natural gas (Mcfd)	216,414	245,996	221,159	237,503
Oil (Bpd)	4,842	4,598	5,220	2,761

Natural gas liquids (Bpd)	3,121	4,048	3,266	3,722
Total (Mcfed)	264,196	297,876	272,077	276,403
Average sales prices: [(3)]				
Natural gas (per Mcf) [(6)]	$ 3.30	$ 3.56	$ 3.41	$ 3.79
Oil (per Bbl)[(7)]	$ 88.42	$ 90.18	$ 83.99	$ 89.71
Natural gas liquids (per Bbl) [(8)]	$ 21.42	$ 32.21	$ 22.17	$ 30.54

Production costs:[(3)(9)]	$ 1.30	$ 1.37	$ 1.34	$ 1.26
Lease operating expenses per Mcfe	0.19	0.30	0.20	0.27
Production taxes per Mcfe	0.24	0.23	0.24	0.26
Transportation and compression expenses per Mcfe	$ 1.74	$ 1.89	$ 1.78	$ 1.79
Total production costs per Mcfe				
Depletion per Mcfe[(3)]	$ 1.53	$ 2.26	$ 1.57	$ 2.23

(1) Represents the cash distributions declared for the respective period and paid by ARP within 45 days after the end of each month within each quarter, based upon the distributable cash flow generated during the respective period.

(2) Production quantities consist of the sum of (i) ARP's proportionate share of production from wells in which it has a direct interest, based on ARP's proportionate net revenue interest in such wells, and (ii) ARP's proportionate share of production from wells owned by the investment partnerships in which ARP has an interest, based on its equity interest in each such partnership and based on each partnership's proportionate net revenue interest in these wells.

(3) "Mcf" and "Mcfd" represent thousand cubic feet and thousand cubic feet per day; "Mcfe" and "Mcfed" represent thousand cubic feet equivalents and thousand cubic feet equivalents per day, and "Bbl" and "Bpd" represent barrels and barrels per day. Barrels are converted to Mcfe using the ratio of six Mcf's to one barrel.

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

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

(6) ARP's average sales prices for natural gas before the effects of financial hedging were $2.28 per Mcf and $3.48 per Mcf for the three months ended September 30, 2015 and 2014, respectively, and $2.32 per Mcf and $4.05 per Mcf for the nine months ended September 30, 2015 and 2014, respectively. These amounts exclude the impact of subordination of production revenues to investor partners within the investor partnerships. Including the effects of subordination, average natural gas sales prices were $3.25 per Mcf ($2.23 per Mcf before the effects of financial hedging) and $3.50 per Mcf ($3.43 per Mcf before the effects of financial hedging) for the three months ended September 30, 2015 and 2014, respectively, and $3.35 per Mcf ($2.27 per Mcf before the effects of financial hedging) and $3.69 per Mcf ($3.97 per Mcf before the effects of financial hedging) for the nine months ended September 30, 2015 and 2014, respectively.

(7) ARP's average sales prices for oil before the effects of financial hedging were $43.25 per barrel and $91.08 per barrel for the three months ended September 30, 2015 and 2014, respectively, and $46.74 per barrel and $93.45 per barrel for the nine months ended September 30, 2015 and 2014, respectively.

(8) ARP's average sales prices for natural gas liquids before the effects of financial hedging were $11.01 per barrel and $32.18 per barrel for the three months ended September 30, 2015 and 2014, respectively, and $13.00 per barrel and $32.16 per barrel for the nine months ended September 30, 2015 and 2014, respectively.

(9) Production costs include labor to operate the wells and related equipment, repairs and maintenance, materials and supplies, property taxes, severance taxes, insurance, production overhead and transportation expenses. These amounts exclude the effects of ARP's proportionate share of lease operating expenses associated with subordination of production revenue to investor partners within ARP's investor partnerships. Including the effects of these costs, lease operating expenses per Mcfe were $1.28 per Mcfe ($1.71 per Mcfe for total production costs) and $1.35 per Mcfe ($1.88 per Mcfe for total production costs) for the three months ended September 30, 2015 and 2014, respectively, and $1.32 per Mcfe ($1.75 per Mcfe for total production costs) and $1.23 per Mcfe ($1.76 per Mcfe for total production costs) for the nine months ended September 30, 2015 and 2014, respectively.

ATLAS RESOURCE PARTNERS, L.P.
CAPITALIZATION INFORMATION
(unaudited; in thousands)

	September 30, 2015	December 31, 2014
Total debt	$ 1,505,047	$ 1,394,460
Less: Cash	(2,418)	(15,247)
Total net debt/(cash)	1,502,629	1,379,213
Partners' capital	244,877	947,537
Total capitalization	$ 1,747,506	$ 2,326,750
Ratio of net debt to capitalization	0.86x	0.59x

ATLAS RESOURCE PARTNERS, L.P
CAPITAL EXPENDITURE DATA
(unaudited; in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Maintenance capital expenditures [1]	$ 13,456	$ 22,400	$ 42,788	$ 46,300
Expansion capital expenditures	19,343	33,530	59,502	104,279
Total	$ 32,799	$ 55,930	$ 102,290	$ 150,579

(1) Oil and gas assets naturally decline in future periods and, as such, ARP recognizes the estimated capitalized cost of stemming such decline in production margin for the purpose of stabilizing its Distributable Cash Flow and cash distributions, which it refers to as maintenance capital expenditures. ARP calculates the estimate of maintenance capital expenditures by first multiplying its forecasted future full year production margin by its expected aggregate production decline of proved developed producing wells. Maintenance capital expenditures are then the estimated capitalized cost of wells that will generate an estimated first year margin equivalent to the production margin decline, assuming such wells are connected on the first day of the calendar year. ARP does not incur specific capital expenditures expressly for the purpose of maintaining or increasing production margin, but such amounts are a hypothetical subset of wells it expects to drill in future periods, including Marcellus Shale, Utica Shale, Mississippi Lime and Marble Falls wells, on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including utilization of public forward commodity exchange prices, current estimates for regional pricing differentials, estimated labor and material rates and other production costs. Estimates for maintenance capital expenditures in the current year are the sum of the estimate calculated in the prior year plus estimates for the decline in production margin from wells connected during the current year and production acquired through acquisitions. ARP considers expansion capital expenditures to be any capital expenditure costs expended that are not maintenance capital expenditures – generally, this will include expenditures to increase, rather than maintain, production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures.

ATLAS RESOURCE PARTNERS, L.P
Financial Information
(unaudited; in thousands, except per unit amounts)

	Three Months Ended September 30,		Nine Months Ended September 30,	
Reconciliation of net income (loss) to non-GAAP measures[1]:	**2015**	**2014**	**2015**	**2014**
Net income (loss)	$ (560,854)	$ 1,885	$ (520,092)	$ (27,558)
Acquisition and related costs	1,154	1,595	5,035	12,765
Depreciation, depletion and amortization	40,463	64,578	125,948	176,077
Asset impairment	672,246	–	672,246	–
Amortization of deferred finance costs	3,661	2,436	14,398	6,290
Non-cash stock compensation expense	289	1,988	4,498	6,342
Maintenance capital expenditures[2]	(13,456)	(13,100)	(42,788)	(34,250)
Preferred unit distributions	(4,275)	(4,475)	(12,613)	(13,298)
Loss on asset sales and disposal	362	92	276	1,686
Cash settlements on commodity derivative contracts[3]	20,282	–	50,407	–
Unrealized gain on mark-to-market derivatives	(131,065)	–	(209,706)	–
Other	39	(18)	22	(16)
Distributable cash flow attributable to limited partners and the general partner[1]	$ 28,846	$ 54,981	$ 87,631	$ 128,038
Supplemental Adjusted EBITDA and Distributable Cash Flow Summary:				
Gas and oil production margin	$ 69,425	$ 78,008	$ 212,426	$ 204,855
Well construction and completion margin	3,008	7,983	8,304	16,554
Administration and oversight margin	5,495	6,177	7,301	12,072
Well services margin	3,444	3,980	11,833	10,916
Gathering and processing margin	(788)	(153)	(1,360)	(613)
Cash general and administrative expenses[4]	(12,535)	(9,541)	(34,867)	(31,787)
Other, net	59	243	102	327
Adjusted EBITDA[1]	68,108	86,697	203,739	212,324
Cash interest expense[5]	(21,531)	(14,141)	(60,707)	(36,738)
Preferred unit distributions	(4,275)	(4,475)	(12,613)	(13,298)
Maintenance capital expenditures[2]	(13,456)	(13,100)	(42,788)	(34,250)
Distributable Cash Flow attributable to limited partners and the general partner[1]	$ 28,846	$ 54,981	$ 87,631	$ 128,038
Discretionary adjustments considered by the Board of Directors of the General Partner in the determination of quarterly cash distributions:				
Net cash from acquisitions from the effective date through closing date[6]	–	10,214	–	30,202
Distributable Cash Flow with discretionary adjustments by the Board of Directors of the General Partner[7]	$ 28,846	$ 65,195	$ 87,631	$ 158,240
Distributions Paid[8]	$ 32,292	$ 52,225	$ 91,330	$ 145,011
per limited partner unit	$ 0.325	$ 0.590	$ 0.975	$ 1.753
Excess (shortfall) of distributable cash flow with discretionary adjustments by the Board of Directors of the General Partner after distributions to unitholders[9]	$ (3,446)	$ 12,970	$ (3,699)	$ 13,229

(1) Although not prescribed under generally accepted accounting principles ("GAAP"), ARP's management believes the presentation of EBITDA, Adjusted EBITDA and Distributable Cash Flow ("DCF") is relevant and useful, because it helps ARP's investors understand its operating performance, allows for easier comparison of its results with other master limited partnerships ("MLP"), and is a critical component in the determination of quarterly cash distributions. As a MLP, ARP is required to distribute 100% of available cash, as defined in its limited partnership agreement ("Available Cash") and subject to cash reserves established by its general partner, to investors on a quarterly basis. ARP refers to Available Cash prior to the establishment of cash reserves as DCF. EBITDA, Adjusted EBITDA and DCF should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. While ARP's management believes that its methodology of calculating EBITDA, Adjusted EBITDA and DCF is generally consistent with the common practice of other

MLPs, such metrics may not be consistent and, as such, may not be comparable to measures reported by other MLPs, who may use other adjustments related to their specific businesses. EBITDA, Adjusted EBITDA and DCF are supplemental financial measures used by the ARP's management and by external users of ARP's financial statements such as investors, lenders under ARP's credit facility, research analysts, rating agencies and others to assess its:

- Operating performance as compared to other publicly traded partnerships and other companies in the upstream energy sector, without regard to financing methods, historical cost basis or capital structure;
- Ability to generate sufficient cash flows to support its distributions to unitholders;
- Ability to incur and service debt and fund capital expansion;
- The viability of potential acquisitions and other capital expenditure projects; and
- Ability to comply with financial covenants in its Credit Facility, which is calculated based upon Adjusted EBITDA

DCF is determined by calculating EBITDA, adjusting it for non-cash, non-recurring and other items to achieve Adjusted EBITDA, and then deducting cash interest expense and maintenance capital expenditures. ARP defines EBITDA as net income (loss) plus the following adjustments:

- Interest expense;
- Income tax expense; and
- Depreciation, depletion and amortization

ARP defines Adjusted EBITDA as EBITDA plus the following adjustments:

- Asset impairments;
- Acquisition and related costs;
- Non-cash stock compensation;
- (Gains) losses on asset disposal;
- Cash proceeds received from monetization of derivative transactions;
- Premiums paid on swaption derivative contracts;
- Non-cash valuation allowances; and
- Other items

ARP adjusts DCF for non-cash, non-recurring and other items for the sole purpose of evaluating its cash distribution for the quarterly period, with EBITDA and Adjusted EBITDA adjusted in the same manner for consistency. ARP defines DCF as Adjusted EBITDA less the following adjustments:

- Cash interest expense;
- Preferred unit cash distributions; and
- Maintenance capital expenditures

(2) Production from oil and gas assets naturally declines in future periods and, as such, ARP recognizes the estimated capitalized cost of stemming such declines in production margin for the purpose of stabilizing its DCF and cash distributions, which it refers to as maintenance capital expenditures. ARP calculates the estimate of maintenance capital expenditures by first multiplying its forecasted future full year production margin by its expected aggregate production decline of proved developed producing wells. Maintenance capital expenditures are then the estimated capitalized cost of wells that will generate an estimated first year margin equivalent to the production margin decline, assuming such wells are connected on the first day of the calendar year. ARP does not incur specific capital expenditures expressly for the purpose of maintaining or increasing production margin, but such amounts are a hypothetical subset of wells it expects to drill in future periods, including Marcellus Shale, Utica Shale, Mississippi Lime, and Marble Falls wells, on undeveloped acreage already leased. Estimated capitalized cost of wells included within maintenance capital expenditures are also based upon relevant factors, including utilization of public forward commodity exchange prices, current estimates for regional pricing differentials, estimated labor and material rates and other production costs. Estimates for maintenance capital expenditures in the current year are the sum of the estimate calculated in the prior year plus estimates for the decline in production margin from wells connected during the current year and production acquired through acquisitions. ARP considers expansion capital expenditures to be any capital expenditure costs expended that are not maintenance capital expenditures – generally, this will include expenditures to increase, rather than maintain, production margin in future periods, as well as land, gathering and processing, and other non-drilling capital expenditures

(3) Includes cash settlements on commodity derivative contracts not previously recorded within accumulated other comprehensive income following the de-designation of hedges on January 1, 2015

(4) Excludes non-cash stock compensation expense and certain acquisition and related costs

(5) Excludes non-cash amortization of deferred financing costs

(6) These amounts reflect net cash proceeds received from the respective effective date through the respective closing date of assets acquired, less estimated and pro forma amounts of maintenance capital expenditures and financing costs. The management of ARP believes these amounts are critical in its evaluation of DCF and cash distributions for the period. Under GAAP, such amounts are characterized as purchase price adjustments and are reflected in the net purchase price paid for the acquired assets, rather than reflected as components of net income or loss for the period. For the three months ended September 30, 2014, such amounts include net cash generated by the Eagle Ford assets from July 1, 2014 to September 30, 2014 of $23.2 million, less pro forma interest expense of $2.0 million, pro-forma preferred unit cash distributions of $1.7 million, and estimated maintenance capital expenditures of $9.3 million. For the nine months ended September 30, 2014, such amounts include net cash generated by the GeoMet assets from January 1, 2014 to May 11, 2014, the Rangely assets from April 1, 2014 to June 30, 2014, and the Eagle Ford assets from July 1, 2014 to September 30, 2014 of $46.3 million, less pro forma interest expense of $2.4 million, pro-forma preferred unit cash distributions of $1.7 million, and estimated maintenance capital expenditures of $12.0 million

(7) Including the discretionary adjustments by the Board of Directors of ARP's General Partner in the determination of quarterly cash distributions, Adjusted EBITDA would have been $109.9 million and $258.6 million for the three and nine months ended September 30, 2014, respectively

(8) Represents the cash distributions declared for the respective period and paid by ARP within 45 days after the end of each month within each quarter, based upon the distributable cash flow generated during the respective period

(9) ARP seeks to at least maintain its current cash distribution in future quarterly periods, and expects to only increase such cash distributions when future Distributable Cash Flow amounts allow for it and are expected to be sustained. ARP's determination of quarterly cash distributions and its resulting determination of the amount of excess (shortfall) those cash distributions generate in comparison to Distributable Cash Flow are based upon its assessment of numerous factors, including but not limited to future commodity price and interest rate movements, variability of well productivity, weather effects, and financial leverage. ARP also considers its historical trailing four quarters of excess or shortfalls and future forecasted excess or shortfalls that its cash distributions generate in comparison to Distributable Cash Flow due to the variability of its Distributable Cash Flow generated each quarter, which could cause it to have more or less excess (shortfalls) generated from quarter to quarter

ATLAS RESOURCE PARTNERS, L.P.
Hedge Position Summary
(as of November 9, 2015)

Natural Gas

Fixed Price Swaps

Production Period Ended December 31,	Average Fixed Price (per mmbtu)[a]	Volumes (mmbtus)[a]
2015[b]	$ 4.19	18,018,000
2016	$ 4.23	53,546,000
2017	$ 4.22	49,920,000
2018	$ 4.17	40,800,000
2019	$ 4.02	15,960,000

Costless Collars

Production Period Ended December 31,	Average Floor Price (per mmbtu)[a]	Average Ceiling Price (per mmbtu)[a]	Volumes (mmbtus)[a]
2015[b]	$ 4.06	$ 4.84	920,000

Put Options – Drilling Partnerships

Production Period Ended December 31,	Average Fixed Price (per mmbtu)[a]	Average Volumes (mmbtus)[a]
2015[b]	$ 4.00	480,000
2016	$ 4.15	1,440,000

WAHA Basis Swaps

Production Period Ended December 31,	Average Fixed Price (per mmbtu)[a]	Average Volumes (mmbtus)[a]
2015[b]	$ (0.0821)	1,600,000

Crude Oil

Fixed Price Swaps

Average

Production Period Ended December 31,	Fixed Price (per bbl)[(a)]	Volumes (bbls)[(a)]
2015[(b)]	$ 87.62	647,000
2016	$ 81.47	1,557,000
2017	$ 77.28	1,140,000
2018	$ 76.28	1,080,000
2019	$ 68.37	540,000

Costless Collars

Production Period Ended December 31,	Average Floor Price (per bbl)[(a)]	Average Ceiling Price (per bbl)[(a)]	Volumes (bbls)[(a)]
2015[(b)]	$ 83.85	$ 110.65	3,250

Natural Gas Liquids

Crude Oil Fixed Price Swaps

Production Period Ended December 31,	Average Fixed Price (per bbl)[(a)]	Volumes (bbls)[(a)]
2016	$ 85.65	84,000
2017	$ 83.78	60,000

Mt Belvieu Propane Swaps

Production Period Ended December 31,	Average Fixed Price (per gallon)	Volumes (bbls)[(a)]
2015[(b)]	$ 1.0161	64,000

Mt Belvieu Butane Swaps

Production Period Ended December 31,	Average Fixed Price (per gallon)	Volumes (bbls)[(a)]
2015[(b)]	$ 1.2481	12,000

Mt Belvieu Iso-Butane Swaps

Production Period Ended December 31,	Average Fixed Price (per gallon)	Volumes (bbls)[a]
2015[b]	$ 1.2631	12,000

Mt Belvieu Natural Gasoline Swaps

Production Period Ended December 31,	Average Fixed Price (per gallon)	Volumes (bbls)[a]
2015[b]	$ 1.9294	40,000

(a) "mmbtu" represents million metric British thermal units; "bbl" represents barrel.
(b) Reflects hedges covering the last three months of 2015.

To view the original version on PR Newswire, visit:http://www.prnewswire.com/news-releases/atlas-resource-partners-lp-reports-operating-and-financial-results-for-the-third-quarter-2015-300175211.html

SOURCE Atlas Resource Partners, L.P.

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