November 5, 2015

Gastar Exploration Announces Third Quarter 2015 Results

- Third Quarter Production Increased 39% Year-Over-Year to 13.6 MBoe/d
- An Enhanced Focus on the Mid-Continent STACK Play with Recent Agreement to Acquire Additional Interests from AMI Co-Participant
- Completed Company's first Meramec STACK well in Oklahoma

HOUSTON, Nov. 5, 2015 /PRNewswire/ -- Gastar Exploration Inc. (NYSE MKT: GST) ("Gastar") today reported financial and operating results for the three and nine months ended September 30, 2015.

Net loss attributable to Gastar's common stockholders as reported for the third quarter of 2015 was $191.8 million, or a loss of $2.47 per share. Excluding a $182.0 million non-cash, pre-tax ceiling test impairment charge, a $4.5 million gain resulting from the mark-to-market of outstanding hedge positions and $481,000 of non-recurring costs related to our pending Mid-Continent acquisition, adjusted net loss attributable to common stockholders for the third quarter 2015 was $13.9 million, or a loss of $0.18 per share. This compares to third quarter 2014 reported net income of $9.8 million, or $0.15 per diluted share. Excluding the impact of a $7.6 million gain resulting from the mark-to-market of outstanding hedge positions, third quarter 2014 adjusted net income was $2.2 million, or $0.03 per diluted share. (See the accompanying reconciliation of net (loss) income to net (loss) income excluding special items at the end of this news release.) Third quarter 2015 results compare to a second quarter 2015 net loss of $118.0 million, or a loss of $1.52 per share, and an adjusted second quarter 2015 net loss of $10.1 million, or a loss of $0.13 per share, which excludes a $100.2 million non-cash, pre-tax ceiling test impairment charge as well as a $7.8 million loss resulting from the mark-to-market of outstanding hedge positions.

Adjusted earnings before interest, income taxes, depreciation, depletion and amortization ("adjusted EBITDA") for the third quarter of 2015 was $14.3 million, a decrease of 43% compared to $25.2 million in the third quarter of 2014 and a decrease of 20% compared to $17.9 million in the second quarter of 2015. (See the accompanying reconciliation of net (loss) income to adjusted EBITDA, a non-GAAP number, at the end of this news release.)

Revenues from oil, condensate, natural gas and natural gas liquids ("NGLs"), before the impact of hedging activities, were $17.1 million in the third quarter of 2015, a decrease of 51% from $35.1 million in the third quarter of 2014 and of 28% from $23.7 million in the second quarter of 2015. The reduction in oil, condensate, natural gas and NGLs revenues from the third quarter of 2014 was primarily the result of a 65% decrease in weighted average realized equivalent prices partially offset by a 39% increase in production. The decrease from the second quarter of 2015 revenues was primarily due to a 27% decline in equivalent product pricing in conjunction with a 2% decrease in average daily production. Revenues from liquids (oil, condensate and NGLs) represented approximately 80% of total production revenues in the third quarter of 2015, compared to 80% for the third quarter of 2014 and 83% during the second quarter of 2015.

We had commodity derivatives contracts in place covering approximately 73% of our natural gas production, 57% of our NGLs production and 38% of our oil and condensate production for the third quarter of 2015. Commodity derivative contracts settled during the period resulted in a $6.8 million increase in revenue for the third quarter of 2015, compared to a reduction in revenue of $1.0 million for the third quarter of 2014 and an increase in revenue of $6.0 million for the second quarter of 2015. Third quarter 2015 hedge benefits enhanced our barrel of oil equivalent (Boe) pricing by approximately 40%, whereas in the third quarter of 2014, hedging reduced our Boe pricing by approximately 3%. We continue to maintain an active hedging program covering a portion of estimated future production, which is reported in our periodic filings with the U.S. Securities and Exchange Commission ("SEC").

Average daily production for the third quarter of 2015 was 13,600 barrels of oil equivalent per day ("Boe/d") as compared to 9,800 Boe/d in the third quarter of 2014 and 13,900 Boe/d in the second quarter of 2015. The year-over-year increase in production was due to new wells being placed on production in both Appalachia and the Mid-Continent. The relatively flat sequential production was due to new wells offsetting natural production declines and the impact of shutting in multiple wells on our WEHLU acreage while nearby wells underwent completion operations. Liquids as a percentage of total equivalent production volumes were 53% (26% crude oil and 27% NGLs) in the third quarter of 2015 compared to 48% (28% crude oil and 20% NGLs) in the third quarter of 2014 and 53% (29% crude oil and 24% NGLs) in the second quarter of 2015.

J. Russell Porter, Gastar's President and CEO, commented, "Gastar's Mid-Continent assets continue to perform well and represent an attractive area for future reserve and production additions. As demonstrated by our recent announcement to market certain of our Marcellus and Utica assets, we are shifting our emphasis away from the Appalachian Basin and toward the Mid-Continent, where returns are more attractive. We are taking meaningful steps to strengthen our position in the Mid-Continent by acquiring additional operating interests in certain producing wells and undeveloped acreage in the STACK and Hunton Limestone formations from our co-participant in an existing area of mutual interest. Once the acquisition is complete, we will be positioned to control the majority of our exploration and development acreage and benefit more fully from the upside potential of the emerging STACK play in the area."

"In addition to the Hunton Limestone potential on our Mid-Continent acreage, we see additional potential for the STACK play which also includes the Meramec, Woodford, Osage and Oswego formations, all of which are being successfully exploited by offset operators. By drilling a well in any of these stacked formations, we are typically able to hold all depths and maintain exposure to multiple plays. Our STACK formation Meramec Shale test, the Deep River 30-1H, was recently completed with 34 frac stages placing approximately 12 million pounds of proppant in an approximate 5,100 foot lateral. Early flow back results are encouraging."

"During the third quarter, we brought online two Upper Hunton wells and two Lower Hunton wells in our WEHLU acreage in the Mid-Continent with continuing positive results. Since our WEHLU acreage is 100% held by production, our near-term outlook is to monitor the production of the recently drilled Upper and Lower Hunton wells and plan for additional drilling on the WEHLU property as commodity prices and capital availability dictate."

"As mentioned earlier, we are marketing certain of our Marcellus and Utica assets which should allow us to further reduce leverage while enhancing our liquidity position and financial flexibility to fund development of our substantial Mid-Continent acreage moving into 2016," said Porter.

The following table provides a summary of Gastar's total net production volumes and overall average commodity prices for the three and nine months ended September 30, 2015 and 2014:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per unit amounts)			
Net Production:				
Oil and condensate (MBbl)	330	250	1,066	660
Natural gas (MMcf)	3,490	2,826	10,360	8,579
NGLs (MBbl)	338	180	854	543
Total net production (MBoe)	1,249	901	3,646	2,633
Net Daily production:				
Oil and condensate (MBbl/d)	3.6	2.7	3.9	2.4
Natural gas (MMcf/d)	37.9	30.7	37.9	31.4
NGLs (MBbl/d)	3.7	2.0	3.1	2.0
Total net daily production (MBoe/d)	13.6	9.8	13.4	9.6
Average sales price per unit(1):				
Oil and condensate per Bbl, including impact of hedging activities (2)	$ 44.84	$ 88.77	$ 48.30	$ 85.47
Oil and condensate per Bbl, excluding impact of hedging activities	$ 38.89	$ 91.17	$ 42.94	$ 89.06
Natural gas per Mcf, including impact of hedging activities (2)	$ 1.57	$ 2.56	$ 1.93	$ 3.34
Natural gas per Mcf, excluding impact of hedging activities	$ 0.99	$ 2.53	$ 1.36	$ 3.73
NGLs per Bbl, including impact of hedging activities (2)	$ 10.64	$ 26.13	$ 14.32	$ 28.09
NGLs per Bbl, excluding impact of hedging activities	$ 2.35	$ 28.56	$ 5.94	$ 31.99
Average sales price per Boe, including impact of hedging activities (2)	$ 19.11	$ 37.87	$ 22.95	$ 38.11
Average sales price per Boe, excluding impact of hedging activities	$ 13.68	$ 38.94	$ 17.81	$ 41.07

(1) The nine months ended September 30, 2014 excludes the benefit of a one-time revenue adjustment related to an arbitration settlement.
(2) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.

Lease operating expenses ("LOE") were $5.2 million in the third quarter of 2015, versus $4.1 million in the third quarter of 2014 and $7.2 million in the second quarter of 2015. Compared to the third quarter of 2014, LOE in the third quarter of 2015 increased $1.1 million as a result of one-time workover costs of $1.1 million for production enhancement operations on certain of our operated WEHLU wells, an increase of $158,000 in ad valorem taxes as a result of higher production volumes and a $72,000 increase in insurance expense offset by a $276,000 decrease in general LOE costs. Compared to the second quarter of 2015, LOE was lower due to a $1.3 million decrease in general LOE costs primarily as a result of lower flowback water disposal costs in Oklahoma, a $380,000 decrease in insurance expense and a $293,000 decrease in workover costs. LOE per Boe was $4.17 in the third quarter of 2015 versus $4.59 in the third quarter of 2014 and $5.74 in the second quarter of 2015. Excluding workover costs, LOE per Boe for the third quarter of 2015 was $3.30 compared to $4.63 per Boe for the third quarter of 2014 and $4.64 per Boe for the second quarter of 2015.

Depreciation, depletion and amortization expense ("DD&A") was $15.4 million in the third quarter of 2015, up from $11.1 million in the third quarter of 2014 and down slightly from $16.1 million in the second quarter of 2015. The year-over-year increase in DD&A expense was the result of 39% higher production volumes. DD&A diminished sequentially due to slightly lower production volumes and a 3% decrease in DD&A rate per Boe. The DD&A rate per Boe for the third quarter of 2015 was $12.32 compared to $12.33 for the third quarter of 2014 and $12.74 in the second quarter of 2015.

General and administrative ("G&A") expense was $4.7 million in the third quarter of 2015 compared to $4.0 million in the third quarter of 2014 and $4.4 million in the second quarter of 2015. G&A expense in the third quarter of 2015 included $1.2 million of non-cash stock-based compensation expense, flat compared to both the third quarter of 2014 and the second quarter of 2015. Excluding stock-based compensation expense, cash G&A expense increased to $3.5 million in the third quarter of 2015 from $2.8 million in the third quarter of 2014 and $3.2 million in the second quarter of 2015. This increase was primarily due to costs related to the pending acquisition of Oklahoma properties from our area of mutual interest ("AMI") co-participant as well as higher legal costs.

Interest expense totaled $7.9 million in the third quarter of 2015, which was up compared to $7.0 million in the third quarter of 2014 and $6.9 million in the second quarter 2015. See "Liquidity" below for more information about available borrowings under our revolving credit facility.

Area Operations Review and Update

Mid-Continent

Net production from the Mid-Continent area averaged 5,600 Boe/d in the third quarter of 2015, compared to 4,500 Boe/d in the third quarter of 2014 and 6,200 Boe/d in the first quarter of 2015. Third quarter 2015 Mid-Continent equivalent production consisted of approximately 53% oil and condensate, 26% natural gas and 21% NGLs. The Mid-Continent represented 42% of our total production, but represented 91% of our pre-hedged gross revenues.

We completed four gross (3.9 net) operated wells during the third quarter of 2015, consisting of two Upper and two Lower Hunton completions on our WEHLU acreage. Subsequent to the end of the third quarter 2015, we have completed one gross (1.0 net) Upper Hunton well and three gross (2.9 net) Lower Hunton wells. We have released our drilling rigs for the remainder of the year in order to preserve liquidity, further evaluate our Hunton and Meramec drilling results and monitor commodity prices and service costs.

The table below shows horizontal wells brought on production since the beginning of 2015 on our operated acreage in the Hunton Limestone formation, all of which are located within our WEHLU property:

Cumulative Production

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates (1) (BOE/d)	Averages(2) BOE/d	Averages(2) % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Upper Hunton Completions							
Warsaw 33-2H	98.3%	4,900	615	210	55%	February 13, 2015	$ 4.4
Blair Farms 31-1H	98.3%	7,500	509	361	78%	May 7, 2015	$ 5.0
Easton 22-4H	98.3%	5,800	604	298	90%	May 20, 2015	$ 2.7
Jetson 8-2H	98.3%	6,100	353	208	87%	August 19, 2015	$ 4.2
Arcadia Farms 15-2H	98.3%	7,700	N/A	267	88%	September 13, 2015	$ 3.1
O' Donnell 5-1H	98.3%	4,400	N/A	119	96%	October 8, 2015	$ 4.5
Lower Hunton Completions							
Warsaw 33-3H	98.3%	6,100	663	203	59%	February 14, 2015	$ 6.9
Easton 22-3H	98.3%	6,700	548	390	79%	May 24, 2015	$ 4.9
Davis 9-2H	98.3%	6,600	N/A	200	83%	August 6, 2015	$ 5.8
Jetson 8-1H	98.3%	5,800	N/A	154	67%	August 19, 2015	$ 5.1
Davis 9-4H	98.3%	7,700	N/A	101	100%	October 3, 2015	$ 5.3
Arcadia Farms 15-1CH	98.3%	6,800	N/A	192	76%	October 9, 2015	$ 5.7
O'Donnell 5-2CH	98.3%	5,600	N/A	176	73%	October 9, 2015	$ 5.6

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through November 1, 2015.

Within our AMI acreage in the Mid-Continent during the third quarter of 2015, we successfully re-drilled one gross (0.8 net) well, the Unruh 1-34H, to correct an initial horizontal casing collapse and the well is currently being placed on production. The table below shows wells brought on production or for which drilling operations have commenced since the beginning of 2015 within our original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates (1) (Boe/d)	Cumulative Production Averages(2) Boe/d	Cumulative Production Averages(2) % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
LB 1-1H	47.6%	4,300	791	181	62%	January 23, 2015	$ 5.2
Hubbard 1-23H(3)	57.0%	4,500	63	19	96%	February 19, 2015	$ 6.1
Boss Hogg 1-14H	50.0%	4,300	129	51	70%	February 21, 2015	$ 7.4
Bo 1-23H	43.8%	4,300	547	250	44%	February 28, 2015	$ 5.0
The River 1-22H	39.7%	3,800	1,250	787	28%	March 14, 2015	$ 4.6
Bigfoot 1-9H	47.4%	4,200	161	88	56%	March 17, 2015	$ 5.1
Falcon 1-5H	51.5%	4,100	1,202	557	71%	April 1, 2015	$ 4.4
Dorothy 1-12H	49.5%	3,900	41	15	74%	April 10, 2015	$ 4.5
Polar Bear 1-20H	47.4%	4,300	403	115	87%	May 5, 2015	$ 4.9
Unruh 1-34H (4)	75.4%	4,400	N/A	N/A	N/A	Commenced flowback	$ 7.6

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through November 1, 2015.
(3) After payout working interest is 49.9%.
(4) Approximate gross costs to drill and complete includes costs to re-drill the well due to an initial horizontal casing collapse.

We recently completed our first operated Meramec Shale well, the Deep River 30-1H, with a 34-stage frac placing approximately 12 million pounds of proppant in an approximate 5,100 foot lateral at an estimated cost of $5.8 million. Early flow back results are encouraging.

The following table provides a summary of Gastar's Mid-Continent production volumes and average commodity prices for the three and nine months ended September 30, 2015 and 2014:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
Mid-Continent	**2015**	**2014**	**2015**	**2014**
Net Production:				
Oil and condensate (MBbl)	274	213	875	516
Natural gas (MMcf)	805	715	2,491	2,004
NGLs (MBbl)	111	83	320	232
Total net production (MBoe)	520	415	1,611	1,082

Net Daily Production:				
Oil and condensate (MBbl/d)	3.0	2.3	3.2	1.9
Natural gas (MMcf/d)	8.7	7.8	9.1	7.3
NGLs (MBbl/d)	1.2	0.9	1.2	0.9
Total net daily production (MBoe/d)	5.6	4.5	5.9	4.0
Average sales price per unit(1):				
Oil and condensate (per Bbl)	$ 44.45	$ 96.09	$ 48.54	$ 98.45
Natural gas (per Mcf)	$ 2.67	$ 3.87	$ 2.76	$ 4.46
NGLs (per Bbl)	$ 10.28	$ 30.42	$ 13.16	$ 34.83
Average sales price per Boe(1)	$ 29.80	$ 62.11	$ 33.27	$ 62.66

(1) Excludes the impact of hedging activities.

In the Mid-Continent, our net capital expenditures in the third quarter of 2015 totaled approximately $35.9 million, resulting in pre-acquisition or divestiture year-to-date expenditures of $91.4 million, including land costs of $14.9 million. Excluding the Mid-Continent acquisition, our total remaining 2015 capital expenditure budget in the Mid-Continent is approximately $8.8 million primarily for drilling and completion.

Appalachian Basin

Net production from the Appalachian Basin area increased to an average of 8,000 Boe/d in the third quarter of 2015 compared to 5,300 Boe/d for the third quarter of 2014 and 7,700 Boe/d in the second quarter of 2015. Appalachian Basin third quarter 2015 equivalent production consisted of 8% oil and condensate, 31% NGLs and 61% natural gas. Year-over-year production volume increases were due to 17 gross (8.5 net) Marcellus Shale wells brought on production from December 2014 to early April 2015 and one gross (0.5 net) Utica Shale/Point Pleasant well brought on production in May 2015. We have deferred our drilling program in the Appalachian Basin and as a result, did not drill or complete any wells during the third quarter of 2015 and, as previously stated, have no additional wells budgeted to be drilled and completed in the Appalachian Basin for the remainder of 2015.

The following table provides a summary of Gastar's Appalachian Basin net production volumes and average commodity prices for the three and nine months ended September 30, 2015 and 2014:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
Marcellus Shale				
Net Production:				
Oil and condensate (MBbl)	56	37	191	144
Natural gas (MMcf)	1,987	1,925	6,215	6,387
NGLs (MBbl)	226	97	533	311
Total net production (MBoe)	613	455	1,760	1,519
Net Daily Production:				
Oil and condensate (MBbl/d)	0.6	0.4	0.7	0.5
Natural gas (MMcf/d)	21.6	20.9	22.8	23.4
NGLs (MBbl/d)	2.5	1.1	2.0	1.1
Total net daily production (MBoe/d)	6.7	4.9	6.4	5.6
Average sales price per unit (1)(2):				
Oil and condensate (per Bbl)	$ 11.64	$ 62.57	$ 17.24	$ 55.42
Natural gas (per Mcf)	$ 0.46	$ 2.14	$ 0.95	$ 3.57
NGLs (per Bbl)	$ (1.56)	$ 26.98	$ 1.60	$ 29.86
Average sales price per Boe (1)(2)	$ 1.97	$ 19.87	$ 5.70	$ 26.37
Utica Shale				
Net Production:				
Natural gas (MMcf)	698	187	1,653	187
Total net production (MBoe)	116	31	276	31
Net Daily Production:				
Natural gas (MMcf/d)	7.6	2.0	6.1	0.7
Total net daily production (MBoe/d)	1.3	0.3	1.0	0.1
Average sales price per unit (1):				
Natural gas (per Mcf)	$ 0.57	$ 1.44	$ 0.81	$ 1.44
Average sales price per Boe (1)	$ 3.39	$ 8.64	$ 4.86	$ 8.64

(1) Excludes the impact of hedging activities.
(2) The nine months ended September 30, 2014 excludes the benefit of a one-time revenue adjustment related to an arbitration settlement.

Net capital expenditures in the Appalachian Basin for the third quarter of 2015 totaled approximately $2.5 million, resulting in year-to-date expenditures of $25.3 million. Our total remaining 2015 capital budget for the Appalachian Basin is approximately $4.9 million for acquiring additional mineral rights in the area.

Liquidity

At September 30, 2015, we had approximately $10.4 million in available cash and cash equivalents and $120.0 million of availability under our $200 million revolving credit facility borrowing base, or total available liquidity of $130.4 million. Subsequent to the end of the third quarter 2015, we signed a purchase and sale agreement to acquire core Oklahoma assets from our original AMI co-participant for a net purchase price of $43.3 million, subject to certain adjustments and customary closing conditions, and the conveyance of approximately 11,000 net non-core, non-producing acres in Blaine, Major and Kingfisher Counties. The transaction is expected to close on or about November 30, 2015. We expect to fund our remaining 2015 capital program of approximately $15.0 million through existing cash balances, internally generated cash flow from operating activities, borrowings under the revolving credit facility, property sales, possible capital markets transactions or some combination thereof.

The Company has also announced that it is currently marketing for sale certain of its Marcellus Shale and Utica/Point Pleasant assets, which are primarily located in Marshall and Wetzel Counties, West Virginia. These assets include producing wells and acreage located in the high-deliverability, dry-gas Utica Shale/Point Pleasant and liquids-rich Marcellus Shale plays. Should this transaction be completed, the Company's liquidity would increase significantly.

Guidance for the Fourth Quarter of 2015

We are updating our previously issued guidance for the full year 2015 and providing the following guidance for the fourth quarter of 2015:

Production	**Fourth Quarter 2015**	**Full-Year 2015(1)**
Net average daily (MBoe/d)(2)	13.1 - 13.6	13.2 - 13.7
Liquids percentage	56% - 60%	52% - 56%
Cash Operating Expenses	**Fourth Quarter 2015**	**Full-Year 2015**
Production taxes (% of production revenues)	5.1% - 5.5%	3.8% - 4.2%
Direct lease operating ($/Boe)	$4.70 - $5.10	$4.90 - $5.20
Transportation, treating & gathering ($/Boe)	$0.40 - $0.45	$0.40 - $0.45
Cash general & administrative ($/Boe)	$2.40 - $2.70	$2.50 - $2.80

(1) Includes adjustment for Oklahoma non-core asset divestiture with property sale effective date of April 1, 2015.
(2) Based on equivalent of 6 thousand cubic feet (Mcf) of natural gas to one barrel of oil, condensate or NGLs.

Conference Call

Gastar has scheduled a conference call for 9:30 a.m. Eastern Time (8:30 a.m. Central Time) on Friday, November 6, 2015. Investors may participate in the call either by phone or audio webcast.

By Phone: Dial 1-412-902-0030 at least 10 minutes before the call. A telephone replay will be available through November 13, 2015 by dialing 1-201-612-7415 and using the conference ID: 13622340.

By Webcast: Visit the Investor Relations page of Gastar's website at www.gastar.com under "Events & Presentations." Please log on a few minutes in advance to register and download any necessary software. A replay will be available shortly after the call.

For more information, please contact Donna Washburn at Dennard-Lascar Associates at 713-529-6600 or e-mail dwashburn@DennardLascar.com.

About Gastar
Gastar Exploration Inc. is an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and natural gas liquids in the United States. Gastar's principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. In Oklahoma, Gastar is developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal play and is testing other prospective formations on the same acreage, including the Meramec Shale and the Woodford Shale, which is referred to as the STACK Play and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec Shale. In West Virginia, Gastar has developed liquids-rich natural gas in the Marcellus Shale and has drilled and completed two successful dry gas Utica Shale/Point Pleasant wells on its acreage. Gastar has engaged Tudor, Pickering, Holt & Co. to market certain of its Marcellus Shale and Utica Shale/Point Pleasant assets located in Marshall and Wetzel Counties, West Virginia. For more information, visit Gastar's website at www.gastar.com.

Forward-Looking Statements
This news release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements give our current expectations, opinion, belief or forecasts of future events and performance. A statement identified by the use of forward-looking words
including "may," "expects," "projects," "anticipates," "plans," "believes," "estimate," "will," "should," and certain of the other foregoing statements may be deemed forward-looking statements. Although Gastar believes that the expectations reflected in such forward-looking statements are reasonable, these statements involve risks and uncertainties that may cause actual future activities and results to be materially different from those suggested or described in this news release. These include risks inherent in oil and natural gas drilling and production activities, including risks with respect to continued low or further declining prices for oil and natural gas that could result in downward revisions to the value of proved reserves or otherwise cause Gastar to further delay or suspend planned drilling and completion operations or reduce production levels, which would adversely impact cash flow; risks relating to the availability of capital to fund drilling operations that can be adversely affected by adverse drilling results, production declines and declines in oil and natural gas prices; risks regarding Gastar's ability to meet financial covenants under its indenture or credit agreements or the ability to obtain amendments or waivers to effect such compliance; risks of fire, explosion, blowouts, pipe failure, casing collapse, unusual or unexpected formation pressures, environmental hazards, and other operating and production risks, which may temporarily or permanently reduce production or cause initial production or test results to not be indicative of future well performance or delay the timing of sales or completion of drilling operations; delays in receipt of drilling permits; risks relating to unexpected adverse developments in the status of properties; borrowing base redeterminations by Gastar's banks; risks relating to the absence or delay in receipt of government approvals or third-party consents; risks relating to Gastar's ability to realize the anticipated benefits from acquired assets; and other risks described in Gastar's Annual Report on Form 10-K and other filings with the U.S. Securities and Exchange Commission ("SEC"), available at the SEC's website at www.sec.gov. Gastar's actual sales production rates can vary considerably from tested initial production rates depending upon completion and production techniques and its primary areas of

operations are subject to natural steep decline rates. By issuing forward-looking statements based on current expectations, opinions, views or beliefs, Gastar has no obligation and, except as required by law, is not undertaking any obligation, to update or revise these statements or provide any other information relating to such statements.

Unless otherwise stated herein, equivalent volumes of production and reserves are based upon an energy equivalent ratio of six Mcf of natural gas to each barrel of liquids (oil, condensate and NGLs), which ratio is not reflective of relative value. Our NGLs are sold as part of our wet gas subject to an incremental NGLs pricing formula based upon a percentage of NGLs extracted from our wet gas production. Our reported production volumes reflect incremental post-processing NGLs volumes and residual gas volumes with which we are credited under our sales contracts.

Targeted expectations and guidance for 2015 are based upon the current revised 2015 capital expenditures budget, which may be subject to revision and reevaluation dependent upon future developments, including drilling results, availability of crews, supplies and production capacity, weather delays, and significant changes in commodities prices or drilling costs.

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- Financial Tables Follow -

GASTAR EXPLORATION INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except share and per share data)			
REVENUES:				
Oil and condensate	$ 12,835	$ 22,793	$ 45,772	$ 61,913
Natural gas	3,459	7,151	14,109	40,129
NGLs	791	5,139	5,071	16,689
Total oil, condensate, natural gas and NGLs revenues	17,085	35,083	64,952	118,731
Gain (loss) on commodity derivatives contracts	11,301	6,663	19,734	(8,761)
Total revenues	28,386	41,746	84,686	109,970
EXPENSES:				
Production taxes	655	1,558	2,317	5,489
Lease operating expenses	5,214	4,136	18,475	13,057
Transportation, treating and gathering	615	397	1,654	3,168
Depreciation, depletion and amortization	15,394	11,111	45,945	33,773
Impairment of oil and natural gas properties	181,966	—	282,118	—
Accretion of asset retirement obligation	131	129	387	376
General and administrative expense	4,683	4,002	13,352	12,658
Total expenses	208,658	21,333	364,248	68,521
(LOSS) INCOME FROM OPERATIONS	(180,272)	20,413	(279,562)	41,449
OTHER INCOME (EXPENSE):				
Interest expense	(7,933)	(6,991)	(22,430)	(20,794)
Investment income and other	4	4	10	15
Foreign transaction loss	—	(1)	—	(7)
(LOSS) INCOME BEFORE PROVISION FOR INCOME TAXES	(188,201)	13,425	(301,982)	20,663
Provision for income taxes	—	—	—	—
NET (LOSS) INCOME	(188,201)	13,425	(301,982)	20,663
Dividends on preferred stock	(3,618)	(3,618)	(10,855)	(10,805)
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ (191,819)	$ 9,807	$ (312,837)	$ 9,858
NET (LOSS) INCOME PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:				
Basic	$ (2.47)	$ 0.16	$ (4.04)	$ 0.17
Diluted	$ (2.47)	$ 0.15	$ (4.04)	$ 0.16
WEIGHTED AVERAGE SHARES OF COMMON STOCK OUTSTANDING:				
Basic	77,628,120	60,006,903	77,453,251	58,982,709
Diluted	77,628,120	63,399,446	77,453,251	62,306,480

GASTAR EXPLORATION INC.
CONSOLIDATED BALANCE SHEETS

	September 30, 2015	December 31, 2014
	(Unaudited)	
	(in thousands, except share data)	

ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 10,351	$ 11,008
Accounts receivable, net of allowance for doubtful accounts of $0, respectively	9,860	30,841
Commodity derivative contracts	16,895	19,687
Prepaid expenses	611	2,083
Total current assets	37,717	63,619
PROPERTY, PLANT AND EQUIPMENT:		
Oil and natural gas properties, full cost method of accounting:		
Unproved properties, excluded from amortization	91,126	128,274
Proved properties	1,233,716	1,124,367
Total oil and natural gas properties	1,324,842	1,252,641
Furniture and equipment	3,061	3,010
Total property, plant and equipment	1,327,903	1,255,651
Accumulated depreciation, depletion and amortization	(891,414)	(563,351)
Total property, plant and equipment, net	436,489	692,300
OTHER ASSETS:		
Commodity derivative contracts	10,710	7,815
Deferred charges, net	2,625	2,586
Advances to operators and other assets	686	9,474
Total other assets	14,021	19,875
TOTAL ASSETS	$ 488,227	$ 775,794
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 12,952	$ 28,843
Revenue payable	5,350	9,122
Accrued interest	10,565	3,528
Accrued drilling and operating costs	6,672	5,977
Advances from non-operators	—	1,820
Commodity derivative contracts	-	—
Commodity derivative premium payable	2,393	2,481
Asset retirement obligation	88	82
Other accrued liabilities	3,123	3,175
Total current liabilities	41,143	55,028
LONG-TERM LIABILITIES:		
Long-term debt	397,189	360,303
Commodity derivative contracts	309	—
Commodity derivative premium payable	3,588	4,702
Asset retirement obligation	6,052	5,475
Total long-term liabilities	407,138	370,480
STOCKHOLDERS' EQUITY:		
Preferred stock, 40,000,000 shares authorized		
Series A Preferred stock, par value $0.01 per share; 10,000,000 shares designated; 4,045,000 shares issued and outstanding at September 30, 2015 and December 31, 2014, respectively, with liquidation preference of $25.00 per share	41	41
Series B Preferred stock, par value $0.01 per share; 10,000,000 shares designated; 2,140,000 shares issued and outstanding at September 30, 2015 and December 31, 2014, respectively, with liquidation preference of $25.00 per share	21	21
Common stock, par value $0.001 per share; 275,000,000 shares authorized; 80,147,147 and 78,632,810 shares issued and outstanding at September 30, 2015 and December 31, 2014, respectively	78	78
Additional paid-in capital	570,937	568,440
Accumulated deficit	(531,131)	(218,294)
Total stockholders' equity	39,946	350,286
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 488,227	$ 775,794

GASTAR EXPLORATION INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Nine Months Ended September 30,	
	2015	2014
	(in thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (loss) income	$ (301,982)	$ 20,663
Adjustments to reconcile net (loss) income to net cash provided by operating activities:		
Depreciation, depletion and amortization	45,945	33,773
Impairment of oil and natural gas properties	282,118	-
Stock-based compensation	3,927	3,704
Mark to market of commodity derivatives contracts:		
Total (gain) loss on commodity derivatives contracts	(19,734)	8,761
Cash settlements of matured commodity derivatives contracts, net	17,913	(7,705)
Cash premiums paid for commodity derivatives contracts	(45)	(185)
Amortization of deferred financing costs	2,652	2,270
Accretion of asset retirement obligation	387	376
Settlement of asset retirement obligation	(80)	(580)
Changes in operating assets and liabilities:		

Accounts receivable	22,552	(4,242)
Prepaid expenses	1,472	(697)
Accounts payable and accrued liabilities	(289)	4,143
Net cash provided by operating activities	54,836	60,281
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development and purchase of oil and natural gas properties	(121,074)	(100,818)
Advances to operators	(2,325)	(43,337)
Acquisition of oil and natural gas properties - refund	—	4,209
Proceeds from sale of oil and natural gas properties	47,866	3,077
(Payments to) proceeds from non-operators	(1,820)	2,422
Purchase of furniture and equipment	(51)	(300)
Net cash used in investing activities	(77,404)	(134,747)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	75,000	58,000
Repayment of revolving credit facility	(40,000)	(58,000)
Proceeds from issuance of common stock, net of issuance costs	—	101,513
Proceeds from issuance of preferred stock, net of issuance costs	—	2,064
Dividends on preferred stock	(10,855)	(10,805)
Deferred financing charges	(804)	(405)
Tax withholding related to restricted stock and performance based unit award vestings	(1,430)	(3,709)
Other	—	13
Net cash provided by financing activities	21,911	88,671
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(657)	14,205
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	11,008	32,393
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 10,351	$ 46,598

NON-GAAP FINANCIAL INFORMATION AND RECONCILIATION

We use both GAAP and certain non-GAAP financial measures to assess performance. Generally, a non-GAAP financial measure is a numerical measure of a company's performance, financial position or cash flows that either excludes or includes amounts that are not normally excluded or included in the most directly comparable measure calculated and presented in accordance with GAAP. Our management believes that these non-GAAP measures provide useful supplemental information to investors in order that they may evaluate our financial performance using the same measures as management. These non-GAAP financial measures should not be considered as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP. In evaluating these measures, investors should consider that the methodology applied in calculating such measures may differ among companies and analysts. A reconciliation is provided below outlining the differences between these non-GAAP measures and their most directly comparable financial measure calculated in accordance with GAAP.

Reconciliation of Net (Loss) Income to Net Income (Loss) Excluding Special Items:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except share and per share data)			
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS[1]	$ (191,819)	$ 9,807	$ (312,837)	$ 9,858
SPECIAL ITEMS:				
(Gains) losses related to the change in mark to market value for outstanding commodity derivatives contracts	(4,511)	(7,623)	(986)	950
Impairment of oil and natural gas properties	181,966	—	282,118	—
Non-recurring general and administrative costs related to acquisition of assets	481	—	481	30
Non-recurring general and administrative costs related to Parent migration	—	15	—	233
Foreign transaction loss	—	1	—	7
ADJUSTED NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS	$ (13,883)	$ 2,200	$ (31,224)	$ 11,078
ADJUSTED NET (LOSS) INCOME PER SHARE OF COMMON STOCK ATTRIBUTABLE TO COMMON STOCKHOLDERS:				
Basic	$ (0.18)	$ 0.04	$ (0.40)	$ 0.19
Diluted	$ (0.18)	$ 0.03	$ (0.40)	$ 0.18
WEIGHTED AVERAGE SHARES OF COMMON STOCK				
Basic	77,628,120	60,006,903	77,453,251	58,982,709
Diluted	77,628,120	63,399,446	77,453,251	62,306,480

(1) The nine months ended September 30, 2014 include the benefit of an $8.6 million one-time adjustment related to an arbitration settlement.

Reconciliation of Cash Flows before Working Capital Changes and as Adjusted for Special Items:

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except share and per share data)			
CASH FLOWS FROM OPERATING ACTIVITIES:				

Net (loss) income[1]	$ (188,201)	$ 13,425	$ (301,982)	$ 20,663
Adjustments to reconcile net (loss) income to net cash provided by operating activities:				
Depreciation, depletion and amortization	15,394	11,111	45,945	33,773
Impairment of oil and natural gas properties	181,966	—	282,118	—
Stock-based compensation	1,154	1,172	3,927	3,704
Mark to market of commodity derivatives contracts:				
Total loss (gain) on commodity derivatives contracts	(11,301)	(6,663)	(19,734)	8,761
Cash settlements of matured commodity derivatives contracts, net	6,505	(1,644)	17,913	(7,705)
Cash premiums paid for commodity derivatives contracts	—	(30)	(45)	(185)
Amortization of deferred financing costs	916	779	2,652	2,270
Accretion of asset retirement obligation	131	129	387	376
Settlement of asset retirement obligation	—	(34)	(80)	(580)
Cash flows from operations before working capital changes	6,564	18,245	31,101	61,077
Foreign transaction loss	—	1	—	7
Dividends on preferred stock	(3,618)	(3,618)	(10,855)	(10,805)
Non-recurring general and administrative costs related to acquisition of assets	481	—	481	30
Non-recurring general and administrative costs related to Parent migration	—	15	—	233
Adjusted cash flows from operations	$ 3,427	$ 14,643	$ 20,727	$ 50,542

(1) The nine months ended September 30, 2014 include the benefit of an $8.6 million one-time adjustment related to an arbitration settlement.

Reconciliation of Net (Loss) Income to Adjusted Earnings Before Interest, Income Taxes, Depreciation, Depletion and Amortization ("Adjusted EBITDA"):

	For the Three Months Ended September 30,		For the Nine Months Ended September 30,	
	2015	2014	2015	2014
	(in thousands, except share and per share data)			
NET (LOSS) INCOME ATTRIBUTABLE TO COMMON STOCKHOLDERS[1]	$ (191,819)	$ 9,807	$ (312,837)	$ 9,858
Interest expense	7,933	6,991	22,430	20,794
Depreciation, depletion and amortization	15,394	11,111	45,945	33,773
Impairment of oil and natural gas properties	181,966	—	282,118	—
EBITDA	13,474	27,909	37,656	64,425
Dividend expense	3,618	3,618	10,855	10,805
Accretion of asset retirement obligation	131	129	387	376
(Gains) losses related to the change in mark to market value for outstanding commodity derivatives contracts	(4,511)	(7,623)	(986)	950
Non-cash stock compensation expense	1,154	1,172	3,927	3,704
Foreign transaction loss	—	1	—	7
Investment income and other	(4)	(4)	(10)	(15)
Non-recurring general and administrative costs related to acquisition of assets	481	—	481	30
Non-recurring general and administrative costs related to Parent migration	—	15	—	233
Adjusted EBITDA	$ 14,343	$ 25,217	$ 52,310	$ 80,515

(1) The nine months ended September 30, 2014 include the benefit of an $8.6 million one-time adjustment related to an arbitration settlement.

To view the original version on PR Newswire, visit:http://www.prnewswire.com/news-releases/gastar-exploration-announces-third-quarter-2015-results-300173599.html

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