Legacy Reserves LP Announces Second Quarter 2017 Results, Acceleration Payment to TSSP, Amended and Restated Joint Development Agreement, Updated Financial Guidance and Increased Capital Budget

MIDLAND, Texas, August 2, 2017- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced second quarter results for 2017 including the following Q2 highlights:

- Brought online an additional 9 horizontal wells in Howard County, TX and Lea County, NM under our Joint Development Agreement ("JDA"), representing 33 horizontal wells brought online since commencement of the program.

- Closed $3.8 million of acreage acquisitions in Howard County, Texas, extending lateral lengths and further coring up our position.

- Generated net income of $5.3 million in the first half of 2017 and a net loss of $11.1 million in Q2 2017.

- Generated EBITDA of $44.3 million representing a 10% increase compared to Q1 2017.

- Reduced lease operating expenses, excluding ad valorem taxes, to $42.3 million representing a 14% decrease compared to Q1 2017.

- Amended and restated our Joint Development Agreement ("JDA") with TPG Sixth Street Partners ("TSSP") including a $141 million acceleration payment increasing our working interest from 20% to 85% in Tranche 1 wells and from 20% to 66.3% in any subsequent tranches.

- Increased our 2017 capital budget to $205 million to fund our increased Permian drilling activity and higher post-reversion JDA working interest.

Paul T. Horne, Chairman of the Board, President and Chief Executive Officer of Legacy's general partner commented, “We are pleased to announce our acceleration payment and amended development agreement. Our horizontal Permian development has been a big success for both us and TSSP. As a result of the amended development agreement, we are able to increase our exposure to this highly-profitable resource, thereby allowing for a meaningful production growth program for the benefit of our equity holders that is expected to positively impact financial leverage ratios over time. We are thankful for TSSP's continued support within the program and for the company as a whole. In addition to our focus on these development projects, we concentrated this quarter on decreasing lifting costs after a heightened level of activity in the first quarter repairing and returning wells to production. These costs were down 14% sequentially, meeting the ambitious goal we set at last quarter’s conference call.

Dan Westcott, Executive Vice President and Chief Financial Officer of Legacy’s general partner, commented, “Today marks another significant step in our transition to a growth-oriented operator focused on efficiently developing our tremendous opportunity set. While these activities are free cash flow negative in the short-term, the long-term profile of our development should improve our leverage metrics over time through meaningful growth in EBITDA. In particular, our revised 2017 Financial Guidance shows estimated 61% and 63% growth in oil production and EBITDA, respectively, in the second half of 2017 relative to the first, driven by our increased participation in our ongoing horizontal development program under the JDA. Despite funding this acquisition under our $300 million 2nd lien term loan, we expect our total leverage to decrease by over 1.0x from Q2 actual to year-end pro forma. These additional interests add considerable value supporting our borrowing base which, given the transaction, is under review. We currently maintain $129.1 million of liquidity under that borrowing base and also have $95 million of additional availability under the 2nd lien term loan through late October. Our team is excited to be able to harness more of this Permian growth opportunity and anticipates continued organic growth in 2018.”

$141 million Acceleration Payment and Amended and Restated Joint Development Agreement

On August 1, we entered into an agreement to make an acceleration payment to acquire by reversion certain of TSSP's pre-reversion interests in the 48 Tranche 1 wells for $141 million, with proceeds from our 2^{nd} lien term loan with GSO Capital Partners ("GSO"). The acceleration payment will cause Legacy's interest in these wells to increase from 20% to 85% of the parties' combined working interest, effective August 1, 2017. We estimate the purchase price represents approximately 2.5x 2017E EBITDA, substantially improving our pro forma credit profile.

As part of the amended and restated JDA, TSSP will fund 40% of the parties' development costs in the next tranche of 16 wells for 33.7% of the parties' combined working interest thereby providing Legacy with a greater participation in future horizontal Permian development (60% funding for a 66.3% working interest). TSSP will have the option to elect to fund an additional tranche of 10 wells on identical terms and will also have the opportunity to participate in a maximum of 6 additional wells per tranche within the defined area of mutual interest. TSSP's post-reversionary working interest (after a 15% internal rate of return with respect to such tranche) has also been proportionately reduced from 15% to 6.3% in the two remaining tranches.

Revised Capital Expenditure Budget

In association with the amended and restated JDA and acceleration payment thereunder, we will incur a much greater percentage of the gross development capital under the JDA on a go-forward basis. After making the acceleration payment, we became responsible for 85% of all remaining Tranche 1 capital costs to be paid regardless of when such costs were incurred.

2017E Capital Program by Category ($ in millions)

	Gross	Net	Percent of Net
Horizontal Permian drilling	$ 327	$ 185	90%
Other drilling	4	2	1%
Other workovers	13	9	4%
East Texas (workovers, G&P, facilities)	6	6	3%
CO_2 + other facilities	3	3	2%
Total capital expenditures	$ 353	$ 205	100%

Updated 2017 Guidance

The following table sets forth certain assumptions used by Legacy to estimate its anticipated results of operations for 2017. These estimates do not include any acquisitions of additional oil or natural gas properties. In addition, these estimates are based on, among other things, assumptions of capital expenditure levels, current indications of supply and demand for oil and natural gas and current operating and labor costs. The guidance set forth below does not constitute any form of guarantee, assurance or promise that the matters indicated will actually be achieved. The guidance below sets forth management's best estimate based on current and anticipated market conditions and other factors. While we believe that these estimates and assumptions are reasonable, they are inherently uncertain and are subject to, among other things, significant business, economic, regulatory, environmental and competitive risks and uncertainties that could cause actual results to differ materially from those we anticipate, as set forth under "Cautionary Statement Relevant to Forward-Looking Information."

	Second Half 2017E Range			**FY 2017E Range[(1)]**		
	($ in thousands unless otherwise noted)					
Production:						
Oil (MBbls)	3,300	-	3,400	5,381	-	5,481
Natural gas liquids (MGal)	17,300	-	17,700	33,467	-	33,867
Natural gas (MMcf)	32,000	-	32,800	63,196	-	63,996
Total (MBoe)	9,045	-	9,288	16,711	-	16,953
Average daily production (Boe/d)	49,158	-	50,478	45,784	-	46,447
Weighted Average NYMEX Differentials:						
Oil (per Bbl)	$(4.25)	-	$(3.75)	$(4.22)	-	$(3.91)
NGL realization (2)	1.00%	-	1.20%	1.11%	-	1.22%
Natural gas (per Mcf)	$(0.30)	-	$(0.20)	$(0.29)	-	$(0.24)
Expenses:						
Oil and natural gas production expenses ($/Boe)	$10.00	-	$10.25	$10.89	-	$11.01
Ad valorem and production taxes (% of revenue)	7.00%	-	7.50%	6.86%	-	7.14%
Cash G&A expenses (3)	$17,000	-	$18,000	$32,668	-	$33,668
Capital expenditures:	$140,000	-	$157,000	$188,315	-	$205,000
Adjusted EBITDA(4):	$130,000	-	$145,000	$214,497	-	$229,497

(1) Represents 1H'17 actuals plus 2H'17 estimates.

(2) Represents the projected percentage of WTI crude oil price per gallon of NGLs.

(3) Consistent with our definition of Adjusted EBITDA, these figures exclude LTIP and transaction-related expenses.

(4) Adjusted EBITDA is a Non-GAAP financial measure. This measure does not include pro forma adjustments permitted under our credit agreements relating to acquired and divested oil or gas properties. A reconciliation of this measure to the nearest comparable GAAP measure is available on our website.

Note: Figures above assume NYMEX strip pricing at 7/31/2017 (2H'17 average oil $49.12 / $2.94 natural gas & 2017 average oil $49.52 / $3.01 natural gas).

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 46,096	$ 41,272	$ 95,238	$ 71,592
Natural gas liquids (NGL) sales	4,921	3,922	9,971	6,375
Natural gas sales	41,830	28,173	87,185	61,259
Total revenue	$ 92,847	$ 73,367	$ 192,394	$ 139,226
Expenses:				
Oil and natural gas production, excluding ad valorem taxes	$ 42,262	$ 41,520	$ 91,490	$ 88,181
Ad valorem taxes	$ 2,540	$ 3,041	$ 4,529	$ 6,403
Total oil and natural gas production	$ 44,802	$ 44,561	$ 96,019	$ 94,584
Production and other taxes	$ 4,145	$ 3,390	$ 8,304	$ 5,963
General and administrative, excluding trans. related costs and LTIP	$ 7,046	$ 7,777	$ 15,669	$ 15,469
Transaction related costs	$ 52	$ 714	$ 84	$ 791
LTIP expense	$ 1,483	$ 2,502	$ 3,380	$ 4,167
Total general and administrative	$ 8,581	$ 10,993	$ 19,133	$ 20,427
Depletion, depreciation, amortization and accretion	$ 27,689	$ 37,668	$ 56,485	$ 74,627
Commodity derivative cash settlements:				
Oil derivative cash settlements received	$ 3,559	$ 9,760	$ 6,698	$ 22,345
Natural gas derivative cash settlements received	$ 3,012	$ 12,333	$ 4,109	$ 22,525
Production:				
Oil (MBbls)	1,044	1,039	2,081	2,108
Natural gas liquids (MGal)	8,514	9,663	16,167	17,904
Natural gas (MMcf)	15,604	16,743	31,196	34,009
Total (MBoe)	3,847	4,060	7,665	8,202
Average daily production (Boe/d)	42,275	44,615	42,348	45,066
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$ 44.15	$ 39.72	$ 45.77	$ 33.96
Natural gas liquids price (per Gal)	$ 0.58	$ 0.41	$ 0.62	$ 0.36
Natural gas price (per Mcf)	$ 2.68	$ 1.68	$ 2.79	$ 1.80
Combined (per Boe)	$ 24.13	$ 18.07	$ 25.10	$ 16.97
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$ 47.56	$ 49.12	$ 48.98	$ 44.56
Natural gas liquids price (per Gal)	$ 0.58	$ 0.41	$ 0.62	$ 0.36
Natural gas price (per Mcf)	$ 2.87	$ 2.42	$ 2.93	$ 2.46
Combined (per Boe)	$ 25.84	$ 23.51	$ 26.51	$ 22.45
Average WTI oil spot price (per Bbl)	$ 48.10	$ 45.46	$ 49.85	$ 39.55
Average Henry Hub natural gas index price (per MMbtu)	$ 3.08	$ 2.15	$ 3.05	$ 2.07
Average unit costs per Boe:				
Oil and natural gas production, excluding ad valorem taxes	$ 10.99	$ 10.23	$ 11.94	$ 10.75
Ad valorem taxes	$ 0.66	$ 0.75	$ 0.59	$ 0.78
Production and other taxes	$ 1.08	$ 0.83	$ 1.08	$ 0.73
General and administrative excluding trans. related costs and LTIP	$ 1.83	$ 1.92	$ 2.04	$ 1.89
Total general and administrative	$ 2.23	$ 2.71	$ 2.50	$ 2.49
Depletion, depreciation, amortization and accretion	$ 7.20	$ 9.28	$ 7.37	$ 9.10

Financial and Operating Results - Three-Month Period Ended June 30, 2017 Compared to Three-Month Period Ended June 30, 2016

- Production decreased 5% to 42,275 Boe/d from 44,615 Boe/d primarily due to natural production declines and individually immaterial divestitures completed in 2016 and 2017. This decline was partially offset by additional production from our drilling operations in Howard County, Texas and Lea County, New Mexico.

- Average realized price, excluding net cash settlements from commodity derivatives, increased 34% to $24.13 per Boe in 2017 from $18.07 per Boe in 2016 driven by the significant increase in commodity prices. Average realized oil price increased 11% to $44.15 in 2017 from $39.72 in 2016 driven by an increase in the average West Texas Intermediate ("WTI") crude oil price of $2.64 per Bbl and improving regional differentials. Average realized natural gas price increased 60% to $2.68 per Mcf in 2017 from $1.68 per Mcf in 2016. This increase is primarily a result of the increase in average Henry Hub natural gas index price of $0.93 per Mcf. Finally, our average realized NGL price increased 41% to $0.58 per gallon in 2017 from $0.41 per gallon in 2016.

- Production expenses, excluding ad valorem taxes, increased 2% to $42.3 million in 2017 from $41.5 million in 2016, primarily due to increased workover and repair activity across all operating regions. On an average cost per Boe basis, production expenses excluding ad valorem taxes increased 7% to $10.99 per Boe in 2017 from $10.23 per Boe in 2016.

- Non-cash impairment expense was $1.8 million in Q2 2017. This impairment was primarily caused by increased expenses in 4 separate producing fields.

- General and administrative expenses, excluding unit-based Long-Term Incentive Plan compensation expense, decreased to $7.1 million in 2017 from $8.5 million in 2016 due to general cost reduction efforts.

- Cash settlements received on our commodity derivatives during 2017 were $6.6 million compared to $22.1 million in 2016. The decline in cash settlements received is a result of the combination of higher commodity prices and reduced nominal volumes hedges in Q2 2017 compared to Q2 2016 as well as lower contracted hedge prices.

- Total development capital expenditures increased to $24.6 million in 2017 from $6.9 million in 2016. The 2017 activity was comprised mainly of the drilling and completion of JDA wells and recompletions and workovers across all of our operating regions.

Financial and Operating Results - Six-Month Period Ended June 30, 2017 Compared to Six-Month Period Ended June 30, 2016

- Production decreased 6% to 42,348 Boe/d from 45,066 Boe/d primarily due to natural production declines and individually immaterial divestitures partially offset by growth from our development activity.

- Average realized price, excluding net cash settlements from commodity derivatives, increased 48% to $25.10 per Boe in 2017 from $16.97 per Boe in 2016 driven by the significant increase in commodity prices. Average realized oil price increased 35% to $45.77 in 2017 from $33.96 in 2016 driven by an increase in the average WTI crude oil price of $10.30 per Bbl and improving regional differentials. Average realized natural gas price increased 55% to $2.79 per Mcf in 2017 from $1.80 per Mcf in 2016. This increase is a result of the increase in the average Henry Hub natural gas index price of approximately $0.98 per Mcf. Finally, our average realized NGL price increased 73% to $0.62 per gallon in 2017 from $0.36 per gallon in 2016.

- Production expenses, excluding ad valorem taxes, increased 4% to $91.5 million in 2017 from $88.2 million in 2016. On an average cost per Boe basis, production expenses increased 11% to $11.94 per Boe in 2017 from $10.75 per Boe in 2016. The increased expenses were primarily due to higher workover and repair activity across all operating regions.

- Non-cash impairment expense totaled $9.9 million in 2017 driven by the continued decline in commodities futures prices and increased expenses. Impairment expense totaled $15.4 million in 2016 due to the decline in commodities futures prices in 2016.

- General and administrative expenses, excluding unit-based LTIP compensation expense totaled $15.8 million in 2017 compared to $16.3 million in 2016, reflecting general cost reduction efforts.

- Cash settlements received on our commodity derivatives during 2017 were $10.8 million compared to $44.9 million in 2016. The decline in cash settlements received is a result of the combination of reduced nominal volumes hedges in 2017 compared to 2016 as well as lower average hedge prices and higher commodity prices.

- Total development capital expenditures increased to $48.3 million in 2017 from $11.7 million in 2016. The 2017 activity was comprised mainly of the drilling and completion of JDA wells and recompletions and workovers across all of our operating regions.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of August 1, 2017, we had entered into derivative agreements to receive average NYMEX WTI crude oil prices and NYMEX Henry Hub, NWPL, SoCal and San Juan natural gas prices as summarized below.

WTI Crude Oil Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2017	92,000	$84.75	$84.75
2018	730,000	$55.04	$55.00 - $55.15

WTI Crude Oil Costless Collars. At an annual WTI market price of $40.00, $50.00 and $65.00, the summary positions below would result in a net price of $45.00, $50.00 and $59.02, respectively for 2017 and $47.06, $50.00 and $60.29, respectively for 2018.

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Call Price per Bbl
July-December 2017	1,104,000	$45.00	$59.02
2018	1,551,250	$47.06	$60.29

WTI Crude Oil Enhanced Swaps. At an annual average WTI market price of $40.00, $50.00 and $65.00, the summary positions below would result in a net price of $65.85, $65.85 and $73.85, respectively for 2017 and $65.50, $65.50 and $73.50, respectively for 2018.

Time Period	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
July-December 2017	92,000	$57.00	$82.00	$90.85
2018	127,750	$57.00	$82.00	$90.50

Midland-to-Cushing WTI Crude Oil Differential Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2017	1,104,000	$(0.30)	$(0.75) - $(0.05)
2018	2,190,000	$(1.22)	$(1.25) - $(1.15)
2019	730,000	$(1.15)	$(1.15)

Natural Gas Swaps (Henry Hub):

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July-December 2017	13,800,000	$3.36	$3.29 - $3.39
2018	42,200,000	$3.25	$3.04 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

Natural Gas Costless Collars (Henry Hub). At an annual Henry Hub price of $2.50, $3.00 and $3.50, the summary position below would result in a net price of $2.90, $3.00 and $3.44, respectively.

Time Period	Volumes (MMBtu)	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2017	7,360,000	$2.90	$3.44

Natural Gas 3-Way Collars (Henry Hub). At an annual average Henry Hub market price of $2.50, $3.00 and $3.50, the summary position below would result in a net price of $3.00, $3.50 and $4.00, respectively for 2017.

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2017	2,520,000	$3.75	$4.25	$5.53

Natural Gas Basis Swaps (NWPL, SoCal and San Juan):

	July-December 2017	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	3,680,000	$(0.16)
SoCal	1,260,400	$0.11
San Juan	1,260,400	$(0.10)

Location and quality differentials attributable to our properties are not reflected in the above prices. The agreements provide for monthly settlement based on the difference between the agreement fixed price and the actual reference oil and natural gas index prices.

Quarterly Report on Form 10-Q

Financial results contained herein are preliminary and subject to the final, unaudited financial statements and related footnotes included in Legacy's Form 10-Q which will be filed on or about August 2, 2017.

Conference Call

As announced on July 19, 2017, Legacy will host an investor conference call to discuss Legacy's results on Thursday, August 3, 2017 at 9:00 a.m. (Central Time). Those wishing to participate in the conference call should dial 877-266-0479. A replay of the call will be available through Thursday, August 10, 2017, by dialing 855-859-2056 or 404-537-3406 and entering replay code 53352520. Those wishing to listen to the live or archived webcast via the Internet should go to the Investor Relations tab of our website at www.LegacyLP.com. Following our prepared remarks, we will be pleased to answer questions from securities analysts and institutional portfolio managers and analysts; the complete call is open to all other interested parties on a listen-only basis.

About Legacy Reserves LP

Legacy Reserves LP is a master limited partnership headquartered in Midland, Texas, focused on the acquisition and development of oil and natural gas properties primarily located in the Permian Basin, East Texas, Rocky Mountain and Mid-Continent regions of the United States. Additional information is available at www.LegacyLP.com.

Additional Information for Holders of Legacy Units

Although Legacy has suspended distributions to both the 8% Series A and Series B Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Preferred Units"), such distributions continue to accrue. Pursuant to the terms of Legacy's partnership agreement, Legacy is required to pay or set aside for payment all accrued but unpaid distributions with respect to the Preferred Units prior to or contemporaneously with making any distribution with respect to Legacy's units. Accruals of distributions on the Preferred Units are treated for tax purposes as guaranteed payments for the use of capital that will generally be taxable to the holders of such Preferred Units as ordinary income even in the absence of contemporaneous distributions.

In addition, Legacy’s unitholders, just like unitholders of other master limited partnerships, are allocated taxable income irrespective of cash distributions paid. Because Legacy’s unitholders are treated as partners that are allocated a share of Legacy’s taxable income irrespective of the amount of cash, if any, distributed by Legacy, unitholders will be required to pay federal income taxes and, in some cases, state and local income taxes on their share of Legacy’s taxable income, including its taxable income associated with cancellation of debt ("COD income") or a disposition of property by Legacy, even if they receive no cash distributions from Legacy. As of January 21, 2016, Legacy has suspended all cash distributions to unitholders and holders of the Preferred Units. Legacy may engage in transactions to de-lever the Partnership and manage its liquidity that may result in the allocation of income and gain to its unitholders without a corresponding cash distribution. For example, during the year ended December 31, 2016, Legacy closed 26 divestitures generating net proceeds of $97.4 million, and Legacy may sell additional assets and use the proceeds to repay existing debt or fund capital expenditures, in which case Legacy's unitholders may be allocated taxable income and gain resulting from the sale, all or a portion of which may be subject to recapture rules and taxed as ordinary income rather than capital gain, without receiving a cash distribution. Further, Legacy may pursue other opportunities to reduce its existing debt, such as debt exchanges, debt repurchases, or modifications that would result in COD income being allocated to its unitholders as ordinary taxable income. The ultimate effect of any income allocations will depend on the unitholder's individual tax position with respect to that holder's units, including the availability of any current or suspended passive losses that may offset some portion of the COD income allocable to a unitholder. Unitholders are encouraged to consult their tax advisors with respect to the consequences of potential transactions that may result in income and gain to unitholders.

Additionally, if Legacy's unitholders, just like unitholders of other master limited partnerships, sell any of their units, they will recognize gain or loss equal to the difference between the amount realized and their tax basis in those units. Prior distributions to unitholders that in the aggregate exceeded the cumulative net taxable income they were allocated for a unit decreased the tax basis in that unit, and will, in effect, become taxable income to Legacy's unitholders if the unit is sold at a price greater than their tax basis in that unit, even if the price received is less than original cost. A substantial portion of the amount realized, whether or not representing gain, may be ordinary income to Legacy's unitholders due to the potential recapture items, including depreciation, depletion and intangible drilling.

Cautionary Statement Relevant to Forward-Looking Information

This press release contains forward-looking statements relating to our operations that are based on management's current expectations, estimates and projections about its operations. Words such as "anticipates," "expects," "intends," "plans," "targets," "projects," "believes," "seeks," "schedules," "estimated," and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and are subject to certain risks, uncertainties and other factors, some of which are beyond our control and are difficult to predict. Among the important factors that could cause actual results to differ materially from those in the forward-looking statements are: realized oil and natural gas prices; production volumes, lease operating expenses, general and administrative costs and finding and development costs; future operating results and the factors set forth under the heading "Risk Factors" in our annual and quarterly reports filed with the SEC. Therefore, actual outcomes and results may differ materially from what is expressed or forecasted in such forward-looking statements. The reader should not place undue reliance on these forward-looking statements, which speak only as of the date of this press release. Unless legally required, Legacy undertakes no obligation to update publicly any forward-looking statements, whether as a result of new information, future events or otherwise.

LEGACY RESERVES LP
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(UNAUDITED)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 46,096	$ 41,272	$ 95,238	$ 71,592
Natural gas liquids (NGL) sales	4,921	3,922	9,971	6,375
Natural gas sales	41,830	28,173	87,185	61,259
Total revenues	92,847	73,367	192,394	139,226
Expenses:				
Oil and natural gas production	44,802	44,561	96,019	94,584
Production and other taxes	4,145	3,390	8,304	5,963
General and administrative	8,581	10,993	19,133	20,427
Depletion, depreciation, amortization and accretion	27,689	37,668	56,485	74,627
Impairment of long-lived assets	1,821	—	9,883	15,447
(Gain) loss on disposal of assets	11,049	(9,141)	5,525	(40,842)
Total expenses	98,087	87,471	195,349	170,206
Operating loss	(5,240)	(14,104)	(2,955)	(30,980)
Other income (expense):				
Interest income	8	16	9	54
Interest expense	(20,614)	(20,302)	(40,747)	(45,478)
Gain on extinguishment of debt	—	19,998	—	150,802
Equity in income (loss) of equity method investees	1	(9)	12	(14)
Net gains (losses) on commodity derivatives	14,516	(37,675)	49,185	(20,637)
Other	402	(98)	362	(192)
Income (loss) before income taxes	(10,927)	(52,174)	5,866	53,555
Income tax expense	(150)	(87)	(571)	(487)
Net income (loss)	$ (11,077)	$ (52,261)	$ 5,295	$ 53,068
Distributions to Preferred unitholders	(4,750)	(4,750)	(9,500)	(8,708)
Net income (loss) attributable to unitholders	$ (15,827)	$ (57,011)	$ (4,205)	$ 44,360
Income (loss) per unit - basic and diluted	$ (0.22)	$ (0.81)	$ (0.06)	$ 0.64
Weighted average number of units used in computing net income (loss) per unit -				
Basic and diluted	72,354	70,071	72,229	69,518

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	June 30, 2017	December 31, 2016
	(In thousands)	
Current assets:		
Cash and cash equivalents	$ 1,214	$ 2,555
Accounts receivable, net:		
Oil and natural gas	42,189	43,192
Joint interest owners	26,673	23,414
Other	401	2
Fair value of derivatives	24,343	6,162
Prepaid expenses and other current assets	8,457	7,447
Total current assets	103,277	82,772
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	3,276,421	3,305,856
Unproved properties	22,287	13,448
Accumulated depletion, depreciation, amortization and impairment	(2,125,166)	(2,137,395)
	1,173,542	1,181,909
Other property and equipment, net of accumulated depreciation and amortization of $11,047 and $10,412, respectively	2,898	3,423
Operating rights, net of amortization of $5,567 and $5,369, respectively	1,449	1,648
Fair value of derivatives	27,767	20,553
Other assets	8,452	8,874
Investments in equity method investees	658	647
Total assets	$ 1,318,043	$ 1,299,826
LIABILITIES AND PARTNERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 8,983	$ 9,092
Accrued oil and natural gas liabilities	61,767	53,248
Fair value of derivatives	94	9,743
Asset retirement obligation	2,980	2,980
Other	9,016	11,546
Total current liabilities	82,840	86,609
Long-term debt	1,180,047	1,161,394
Asset retirement obligation	268,803	269,168
Fair value of derivatives	—	4,091
Other long-term liabilities	643	643
Total liabilities	1,532,333	1,521,905
Commitments and contingencies		
Partners' deficit		
Series A Preferred equity - 2,300,000 units issued and outstanding at June 30, 2017 and December 31, 2016	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at June 30, 2017 and December 31, 2016	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at June 30, 2017 and December 31, 2016	30,814	30,814
Limited partners' deficit - 72,559,430 and 72,056,097 units issued and outstanding at June 30, 2017 and December 31, 2016, respectively	(474,412)	(482,200)
General partner's deficit (approximately 0.03%)	(145)	(146)
Total partners' deficit	(214,290)	(222,079)
Total liabilities and partners' deficit	$ 1,318,043	$ 1,299,826

Non-GAAP Financial Measures

"Adjusted EBITDA" is a non-generally accepted accounting principles ("non-GAAP") measure which may be used periodically by management when discussing our financial results with investors and analysts. The following presents a reconciliation of this non-GAAP financial measure to its nearest comparable generally accepted accounting principles ("GAAP") measure.

Adjusted EBITDA is presented as management believes it provides additional information concerning the performance of our business and is used by investors and financial analysts to analyze and compare our current operating and financial performance relative to past performance and such performances relative to that of other publicly traded partnerships in the industry. Adjusted EBITDA may not be comparable to similarly titled measures of other publicly traded limited partnerships or limited liability companies because all companies may not calculate such measures in the same manner.

Certain factors impacting Adjusted EBITDA may be viewed as temporary, one-time in nature, or being offset by reserves from past performance or near-term future performance. Financial results are also driven by various factors that do not typically occur evenly throughout the year that are difficult to predict, including rig availability, weather, well performance, the timing of drilling and completions and near-term commodity price changes.

"Adjusted EBITDA" should not be considered as an alternative to GAAP measures, such as net income, operating income, cash flow from operating activities, or any other GAAP measure of financial performance.

The following table presents a reconciliation of our consolidated net income (loss) to Adjusted EBITDA:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Net income (loss)	$ (11,077)	$ (52,261)	$ 5,295	$ 53,068
Plus:				
Interest expense	20,614	20,302	40,747	45,478
Gain on extinguishment of debt	—	(19,998)	—	(150,802)
Income tax expense	150	87	571	487
Depletion, depreciation, amortization and accretion	27,689	37,668	56,485	74,627
Impairment of long-lived assets	1,821	—	9,883	15,447
(Gain) loss on disposal of assets	11,049	(9,141)	5,525	(40,842)
Equity in (income) loss of equity method investees	(1)	9	(12)	14
Unit-based compensation expense	1,483	2,502	3,380	4,167
Minimum payments received in excess of overriding royalty interest earned(1)	470	—	915	802
Net (gains) losses on commodity derivatives	(14,516)	37,675	(49,185)	20,637
Net cash settlements received on commodity derivatives	6,571	22,093	10,807	44,870
Transaction related expenses	52	714	84	791
Adjusted EBITDA	$ 44,305	$ 39,650	$ 84,495	$ 68,744

(1) Minimum payments received in excess of overriding royalties earned under a contractual agreement expiring December 31, 2019. The remaining amount of the minimum payments is recognized in net income.

CONTACT: Legacy Reserves LP
Dan Westcott
Executive Vice President and Chief Financial Officer
432-689-5200