Legacy Reserves LP Announces Fourth Quarter and Annual 2016 Results and 2017 Guidance

MIDLAND, Texas, February 22, 2017 - (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced fourth quarter and annual results for 2016. 2016 included the following highlights:

- Generated record annual production of 43,803 Boe/d up 14% from 38,523 Boe/d in 2015
- Reduced production expenses, excluding ad valorem taxes, by $13.4 million or 7% relative to 2015 and reported record-low LOE/Boe of $10.59
- Sold $97.4 million of assets that generated combined annualized negative cash flow in 26 transactions
- Reduced total debt by $269.4 million and projected annualized interest expense by $11.7 million
- Entered into a new Second Lien Term Loan Facility with GSO Capital Partners LP ("GSO") providing $300.0 million of committed capital, of which $60 million has been drawn
- Restarted horizontal Permian drilling with an increased capital commitment from TPG Special Situation Partners to a total of $275.0 million and 48 wells
    - Currently operating two horizontal rigs under the JDA program; one in Lea County, NM and one in Howard County, TX
    - Completed nine additional horizontal wells since recommencing drilling operations in June 2016, resulting in 24 total horizontal wells brought online since initiating the program in July 2015

Paul T. Horne, Chairman of the Board, President and Chief Executive Officer, commented, "Our company accomplished several key objectives in 2016. Despite a very difficult commodity price environment, 50% and 32% below the average over the prior five years for oil and natural gas, respectively, we reduced debt by $269 million by rationalizing non-core assets and using a portion of the proceeds to repurchase debt at a discount, drilling tremendous horizontal wells in the Permian, and raising a new 2nd Lien facility to help fund any future capital needs. For 2017, we are planning a $55 million capital budget based on a very active, 92% operated gross capital budget of $225.0 million, focused primarily on our horizontal Permian development. Such development, including the 24 wells we have drilled, completed and brought online under our Development Agreement, provides us with great encouragement for our significant Permian inventory. Despite this recent success, our balance sheet remains over-levered."

"Given the significant commodity price downturn and corresponding upheaval of the upstream MLP market, we anticipate the continued suspension of distributions and will focus on growing unitholder value by growing asset value. Our unique blend of stable, low-decline PDP combined with high-impact Permian horizontal development presents a distinctive opportunity for us that we intend to grow for the benefit of our unitholders."

Dan Westcott, Executive Vice President and Chief Financial Officer, commented, "I am proud of the team effort that enabled such great execution this past year. While we certainly are not out of the woods yet, the recent rise in commodity prices and our horizontal drilling success that has helped delineate our tremendous horizontal potential across the Permian gives us great promise of a brighter future. We look forward to continuing to delever the balance sheet, exploiting our Permian opportunities and finding new successes in 2017 and beyond."

Proved Reserves

The following information represents estimates of our proved reserves as of December 31, 2016 which have been prepared in compliance with the SEC rules using an average WTI price, as posted by Plains Marketing L.P., of $39.25 per Bbl for oil and an average natural gas price, as posted by Platts Gas Daily, of $2.48 per MMBtu. Using the five-year average forward price as of February 14, 2017 for both WTI oil and NYMEX natural gas, we estimate the cumulative projected production from our year-end proved reserves would increase by approximately 14% to 164.7 MMBoe and the Standardized Measure would increase approximately 69% to $970.1 million.

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	% Liquids	% PDP	% Total	Standardized Measure ($ thousands)
Permian Basin	25,491	89,446	932	41,331	63.9 %	83.4 %	28.6 %	$ 280,048
East Texas	63	339,034	95	56,664	0.3 %	98.1 %	39.1 %	153,976
Rocky Mountain	4,970	188,277	4,474	40,823	23.1 %	99.2 %	28.2 %	116,540
Mid-Continent	1,934	10,263	2,342	5,986	71.4 %	95.6 %	4.1 %	25,062
Total	**32,458**	**627,020**	**7,843**	**144,804**	**27.8%**	**94.1%**	**100.0%**	**$ 575,626**

2017 Capital Program By Category

	Gross	Net	Percent of Net
	(In millions)		
Horizontal Permian Drilling	$ 197.0	$ 33.6	61%
Other Drilling	4.6	1.1	2%
Other Workovers	7.3	4.9	9%
East Texas (Workovers, G&P, Facilities)	7.8	7.7	14%
CO_2 + Other Facilities	8.3	7.7	14%
Total Capital Expenditures	$ 225.0	$ 55.0	100%

We serve as operator of approximately 92% of our anticipated capital program, and accordingly, maintain significant control of the capital program budget and may deviate materially from the figures above based on market conditions (or otherwise).

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."

	FY 2017E Range		
	($ in thousands unless otherwise noted)		
Production:			
Oil (MBbls)	4,300	-	4,400
Natural gas liquids (MGal)	35,800	-	36,800
Natural gas (MMcf)	61,300	-	62,900
Total (MBoe)	15,369	-	15,760
Average daily production (Boe/d)	42,107	-	43,178
Weighted Average NYMEX Differentials:			
Oil (per Bbl)	$(4.75)	-	$(4.00)
NGL realization (1)	1.05%	-	1.23%
Natural gas (per Mcf)	$(0.31)	-	$(0.26)
Expenses:			
Oil and natural gas production expenses ($/Boe)	$10.80	-	$11.20
Ad valorem and production taxes (% of revenue)	7.50%	-	8.00%
Cash G&A expenses (2)	$33,000	-	$34,000
Capital expenditures:	$55,000	-	$60,000
Adjusted EBITDA(3):	$195,000	-	$215,000

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

(2) Consistent with our definition of Adjusted EBITDA, these figures exclude LTIP expenses. Cash settlements of LTIP (not included herein) impact Distributable Cash Flow.

(3) Adjusted EBITDA is a Non-GAAP financial measure. A reconciliation of this measure to the nearest comparable GAAP measure is available on our website.

Note: Figures above assume NYMEX strip pricing at 2/14/2017 (2017 Avg Oil $55.24 / $3.24 Gas).

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended December 31, 2016	Three Months Ended December 31, 2015	Twelve Months Ended December 31, 2016	Twelve Months Ended December 31, 2015
	(In thousands, except per unit data)			
Revenues				
Oil sales	$ 42,164	$ 40,653	$ 152,507	$ 199,841
Natural gas liquids sales	5,574	3,778	15,406	16,645
Natural gas sales	43,853	35,510	146,444	122,293
Total revenues	$ 91,591	$ 79,941	$ 314,357	$ 338,779
Expenses:				
Oil and natural gas production	$ 41,456	$ 48,436	$ 169,755	$ 183,163
Ad valorem taxes	172	3,169	9,578	11,328
Total	$ 41,628	$ 51,605	$ 179,333	$ 194,491
Production and other taxes	$ 4,318	$ 3,345	$ 14,267	$ 16,383
General and administrative excluding transaction costs and LTIP	$ 8,237	$ 8,574	$ 31,196	$ 30,919
Acquisition costs	4,158	743	5,245	8,919
LTIP expense	1,586	1,689	7,198	6,673
Total general and administrative	$ 13,981	$ 11,006	$ 43,639	$ 46,511
Depletion, depreciation, amortization and accretion	$ 39,719	$ 54,952	$ 150,414	$ 177,258
Commodity derivative cash settlements:				
Oil derivative cash settlements received	$ 7,030	$ 15,298	$ 37,464	$ 91,953
Natural gas derivative cash settlements received	992	13,314	27,041	40,972
Total commodity derivative cash settlements	$ 8,022	$ 28,612	$ 64,505	$ 132,925
Production:				
Oil (MBbls)	949	1,088	4,019	4,608
Natural gas liquids (MGal)	9,111	10,874	36,757	42,210
Natural gas (MMcf)	16,243	16,997	66,824	50,687
Total (MBoe)	3,873	4,180	16,032	14,061
Average daily production (Boe/d)	42,098	45,435	43,803	38,523
Average sales price per unit (excluding commodity derivative cash settlements):				
Oil price (per Bbl)	$ 44.43	$ 37.36	$ 37.95	$ 43.37
Natural gas liquids price (per Gal)	$ 0.61	$ 0.35	$ 0.42	$ 0.39
Natural gas price (per Mcf)(a)	$ 2.70	$ 2.09	$ 2.19	$ 2.41
Combined (per Boe)	$ 23.65	$ 19.12	$ 19.61	$ 24.09
Average sales price per unit (including commodity derivative cash settlements):				
Oil price (per Bbl)	$ 51.84	$ 51.43	$ 47.27	$ 63.32
Natural gas liquids price (per Gal)	$ 0.61	$ 0.35	$ 0.42	$ 0.39
Natural gas price (per Mcf)(a)	$ 2.76	$ 2.87	$ 2.60	$ 3.22
Combined (per Boe)	$ 25.72	$ 25.97	$ 23.63	$ 33.55
Average WTI oil spot price (per Bbl)	$ 49.14	$ 41.94	$ 43.29	$ 48.66
Average Henry Hub natural gas index price (per MMbtu)	$ 3.04	$ 2.12	$ 2.52	$ 2.62
Average unit costs per Boe:				
Production costs, excluding production and other taxes	$ 10.70	$ 11.59	$ 10.59	$ 13.03
Ad valorem taxes	$ 0.04	$ 0.76	$ 0.60	$ 0.81
Production and other taxes	$ 1.11	$ 0.80	$ 0.89	$ 1.17
General and administrative excluding LTIP & acquisition costs	$ 2.13	$ 2.05	$ 1.95	$ 2.20
Total general and administrative	$ 3.61	$ 2.63	$ 2.72	$ 3.31
Depletion, depreciation, amortization and accretion	$ 10.26	$ 13.15	$ 9.38	$ 12.61

Annual Financial and Operating Results - 2016 Compared to 2015

- Production increased 14% to an annual record of 43,803 Boe/d from 38,523 Boe/d primarily due to a full year of production from our acquisitions of East Texas properties, partially offset by individually immaterial divestitures and natural production declines.

- Average realized price, excluding net cash settlements from commodity derivatives, decreased 19% to $19.61 per Boe in 2016 from $24.09 per Boe in 2015. Average realized oil price decreased 12% to $37.95 in 2016 from $43.37 in 2015. This decrease was primarily driven by a decrease in the average West Texas Intermediate ("WTI") crude oil price of $5.37 per Bbl. Average realized natural gas price decreased 9% to $2.19 per Mcf in 2016 from $2.41 per Mcf in 2015. This decrease was primarily driven by a decrease in the average Henry Hub natural gas index price of $0.10 per Mcf and an increase in realized regional differentials. Finally, our average realized NGL price increased 8% to $0.42 per gallon in 2016 from $0.39 per gallon in 2015.

- Production expenses, excluding ad valorem taxes, decreased 7% to $169.8 million in 2016 from $183.2 million in 2015 due to our cost containment efforts on our historical assets, partially offset by costs associated with the acquisitions of East Texas properties. On an average cost per Boe basis, production expenses decreased 19% to $10.59 per Boe in 2016 from $13.03 per Boe in 2015, driven primarily by a reduction in the production expenses from our historical assets as well as the inclusion of lower cost natural gas properties from our acquisitions of East Texas properties.

- Non-cash impairment expense totaled $61.8 million primarily driven by well performance and the further decline in oil and natural gas prices during 2016.

- General and administrative expenses, excluding acquisition costs and unit-based Long-Term Incentive Plan ("LTIP") compensation expense totaled $31.2 million in 2016 compared to $30.9 million in 2015. This small increase was primarily attributable to costs associated with additional personnel commensurate with the growth of our asset base, partially offset by general cost reduction efforts.

- Cash settlements received on our commodity derivatives during 2016 were $64.5 million as compared to $132.9 million in 2015.

- Total development capital expenditures decreased to $29.5 million in 2016 from $36.8 million in 2015.

Financial and Operating Results - Fourth Quarter 2016 Compared to Fourth Quarter 2015

- Production decreased 7% to 42,098 Boe/d from 45,435 Boe/d primarily due to production decreases related to individually immaterial divestitures and natural production declines.

- Average realized price, excluding net cash settlements from commodity derivatives, increased 24% to $23.65 per Boe in 2016 from $19.12 per Boe in 2015. Average realized oil price increased 19% to $44.43 per Bbl in 2016 from $37.36 per Bbl in 2015. This increase of $7.07 was primarily attributable to the increase in the average WTI crude oil price of $7.20. Average realized natural gas prices increased 29.2% to $2.70 per Mcf in 2016 from $2.09 per Mcf in 2015. This increase of $0.61 was primarily attributable to a $0.92 increase in the average Henry Hub natural gas price index, partially offset by higher realized regional differentials. Finally, our average realized NGL price increased 74% to $0.61 per gallon in 2016 from $0.35 per gallon in 2015.

- Production expenses, excluding ad valorem taxes, decreased 14% to $41.5 million in 2016 from $48.4 million in 2015. Production expenses decreased primarily due to cost reduction efforts on our historical properties and individually immaterial divestitures. On a per Boe basis, production expenses decreased to $10.70 from $11.59 or 8% driven by cost reductions in our ongoing operations.

- Non-cash impairment expense totaled $41.7 million primarily driven by well performance during the period.

- General and administrative expenses, excluding acquisition costs and LTIP compensation expense, decreased to $8.2 million in 2016 from $8.6 million in 2015 due to general cost reduction efforts.

- Cash settlements received on our commodity derivatives were $8.0 million during 2016 compared to $28.6 million in 2015.

- Total development capital expenditures were $11.0 million in the fourth quarter of 2016.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of February 21, 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:

Calendar Year	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
2017	182,500	$84.75	$84.75
2018	730,000	$55.04	$55.00 - $55.15

WTI Crude Oil Costless Collars. As an illustrative example, 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
2017	2,190,000	$45.00	$59.02
2018	1,551,250	$47.06	$60.29

WTI Crude Oil 3-Way Collars. As an illustrative example, at an annual average WTI market price of $40.00, $50.00 and $65.00, the summary position below would result in a net price of $65.00, $75.00 and $85.00, respectively.

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2017	72,400	$60.00	$85.00	$104.20

Crude Oil Enhanced Swaps. As an illustrative example, 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.

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2017	182,500	$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
2017	2,190,000	$(0.30)	$(0.75) - $(0.05)
2018	1,460,000	$(1.25)	$(1.25)

Natural Gas Swaps (Henry Hub):

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2017	27,600,000	$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). As an illustrative example, 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
2017	14,600,000	$2.90	$3.44

Natural Gas 3-Way Collars (Henry Hub). As an illustrative example, 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.

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2017	5,040,000	$3.75	$4.25	$5.53

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

	2017	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	7,300,000	$(0.16)
SoCal	2,500,250	$0.11
San Juan	2,500,250	$(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.

Annual Report on Form 10-K

Our consolidated, audited financial statements and related footnotes will be available in our annual 2016 Form 10-K which will be filed on or about February 22, 2017.

Conference Call

As announced on February 8, 2017, Legacy will host an investor conference call to discuss Legacy's results and corresponding presentation materials on Thursday, February 23, 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, March 2, 2017, by dialing 855-859-2056 or 404-537-3406 and entering replay code 61542356. Those wishing to listen to the live or archived web cast via the Internet or view the corresponding presentation materials 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 delever 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 expenditure, 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 its 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 December 31,		Twelve Months Ended December 31,	
	2016	2015	2016	2015
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 42,164	$ 40,653	$ 152,507	$ 199,841
Natural gas liquids (NGL) sales	5,574	3,778	15,406	16,645
Natural gas sales	43,853	35,510	146,444	122,293
Total revenues	91,591	79,941	314,357	338,779
Expenses:				
Oil and natural gas production	41,628	51,605	179,333	194,491
Production and other taxes	4,318	3,345	14,267	16,383
General and administrative	13,981	11,006	43,639	46,511
Depletion, depreciation, amortization and accretion	39,719	54,952	150,414	177,258
Impairment of long-lived assets	41,731	326,349	61,796	633,805
Gain on disposal of assets	(806)	(5,539)	(50,095)	(3,972)
Total expenses	140,571	441,718	399,354	1,064,476
Operating loss	(48,980)	(361,777)	(84,997)	(725,697)
Other income (expense):				
Interest income	13	2	67	329
Interest expense	(16,502)	(17,988)	(79,060)	(76,891)
Gain on extinguishment of debt	—	—	150,802	—
Equity in income of equity method investees	7	29	—	126
Net gains (losses) on commodity derivatives	(38,913)	34,270	(41,224)	98,253
Other	309	120	(179)	841
Loss before income taxes	(104,066)	(345,344)	(54,591)	(703,039)
Income tax (expense) benefit	(519)	1,208	(1,229)	1,498
Net Loss	$ (104,585)	$ (344,136)	$ (55,820)	$ (701,541)
Distributions to preferred unitholders	(5,542)	(4,750)	(19,000)	(19,000)
Net loss attributable to unitholders	$ (110,127)	$ (348,886)	$ (74,820)	$ (720,541)
Loss per unit — basic and diluted	$ (1.53)	$ (5.06)	$ (1.06)	$ (10.45)
Weighted average number of units used in computing loss per unit —				
Basic and diluted	72,056	68,950	70,605	68,928

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	December 31, 2016	December 31, 2015
	(In thousands)	
ASSETS		
Current assets:		
Cash	$ 2,555	$ 2,006
Accounts receivable, net:		
Oil and natural gas	43,192	33,944
Joint interest owners	23,414	25,378
Other	2	86
Fair value of derivatives	6,162	63,711
Prepaid expenses and other current assets	7,447	4,334
Total current assets	82,772	129,459
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	3,305,856	3,485,634
Unproved properties	13,448	13,424
Accumulated depletion, depreciation, amortization and impairment	(2,137,395)	(2,090,102)
	1,181,909	1,408,956
Other property and equipment, net of accumulated depreciation and amortization of $10,412 and $8,915, respectively	3,423	4,575
Operating rights, net of amortization of $5,369 and $4,953, respectively	1,648	2,064
Fair value of derivatives	20,553	56,373
Other assets	8,874	11,047
Investments in equity method investees	647	646
Total assets	$1,299,826	$1,613,120
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 9,092	$ 13,581
Accrued oil and natural gas liabilities	53,248	50,573
Fair value of derivatives	9,743	2,019
Asset retirement obligation	2,980	3,496
Other	11,546	11,424
Total current liabilities	86,609	81,093
Long-term debt	1,161,394	1,427,614
Asset retirement obligation	269,168	282,909
Fair value of derivatives	4,091	—
Other long-term liabilities	643	1,181
Total liabilities	1,521,905	1,792,797
Commitments and contingencies		
Partners' equity (deficit):		
Series A Preferred equity - 2,300,000 units issued and outstanding at December 31, 2016 and December 31, 2015	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at December 31, 2016 and December 31, 2015	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at December 31, 2016 and December 31, 2015	30,814	30,814
Limited partners' deficit - 72,056,097 and 68,949,961 units issued and outstanding at December 31, 2016 and 2015, respectively	(482,200)	(439,811)
General partner's deficit (approximately 0.03%)	(146)	(133)
Total partners' deficit	(222,079)	(179,677)
Total liabilities and partners' deficit	$1,299,826	$1,613,120

Non-GAAP Financial Measures

This press release, the financial tables and other supplemental information include "Adjusted EBITDA" which 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. Consistent with practices common to publicly traded partnerships, the board of directors of our general partner historically has not varied the distribution it declares based on such timing effects.

"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.

Adjusted EBITDA is defined as net income (loss) plus:

- Interest expense;
- Income tax expense (benefit);
- (Gain) loss on extinguishment of debt
- Depletion, depreciation, amortization and accretion;
- Impairment of long-lived assets;
- (Gain) loss on sale of partnership investment;
- (Gain) loss on disposal of assets;
- Equity in (income) loss of equity method investees;
- Unit-based compensation expense (benefit) related to LTIP unit awards accounted for under the equity or liability methods;
- Minimum payments received in excess of overriding royalty interest earned;
- Equity in EBITDA of equity method investee;
- Net (gains) losses on commodity derivatives;
- Net cash settlements received (paid) on commodity derivatives; and
- Transaction related expenses.

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2016	2015	2016	2015
	(In thousands)			
Net loss	$ (104,585)	$ (344,136)	$ (55,820)	$ (701,541)
Plus:				
Interest expense	16,502	17,988	79,060	76,891
Gain on debt extinguishment	—	—	(150,802)	
Income tax expense (benefit)	519	(1,208)	1,229	(1,498)
Depletion, depreciation, amortization and accretion	39,719	54,952	150,414	177,258
Impairment of long-lived assets	41,731	326,349	61,796	633,805
Gain on disposal of assets	(806)	(5,539)	(50,095)	(3,972)
Equity in income of equity method investees	(7)	(29)	—	(126)
Unit-based compensation expense	1,586	1,688	7,198	6,673
Minimum payments received in excess of overriding royalty interest earned(1)	434	—	1,659	1,130
Equity in EBITDA of equity method investee(2)	—	—	—	169
Net (gains) losses on commodity derivatives	38,913	(34,270)	41,224	(98,253)
Net cash settlements received on commodity derivatives	8,022	28,612	64,505	132,925
Transaction related expenses	4,158	743	5,245	8,919
Adjusted EBITDA	$ 46,186	$ 45,150	$ 155,613	$ 232,380

(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 are recognized in net income.

(2) EBITDA applicable to equity method investee is defined as the equity method investee's net income or loss plus interest expense and depreciation. We divested our interest in this investee in May of 2015.

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