Legacy Reserves LP Announces Fourth Quarter and Annual 2015 Results

MIDLAND, Texas, February 24, 2016- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced fourth quarter and annual results for 2015. Financial results contained herein are preliminary and subject to the audited financial statements included in Legacy's Form 10-K to be filed on or about February 26, 2016.

A summary of selected financial information follows. For consolidated financial statements, please see accompanying tables.

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2015	2014	2015	2014
	(dollars in millions)			
Production (Boe/d)	45,435	32,783	38,523	26,962
Revenue	$ 79.9	$ 119.6	$ 338.8	$ 532.3
Net Loss [a]	$ (344.1)	$ (331.5)	$ (701.5)	$ (283.6)
Adjusted EBITDA [b]	$ 45.2	$ 64.7	$ 232.4	$ 278.2
Distributable Cash Flow [b]	$ 12.9	$ 24.2	$ 103.5	$ 128.1

(a) Includes non-cash impairment charges of $326.3 million and $440.1 million for the fourth quarter of 2015 and 2014, respectively, and $633.8 million and $448.7 million for the years ended December 31, 2015 and 2014, respectively.
(b) Non-GAAP financial measure. Please see Adjusted EBITDA and Distributable Cash Flow table at the end of this press release for a reconciliation of these measures to their nearest comparable GAAP measure.

2015 highlights include:

- Completed $489.3 million of acquisitions, net of properties immediately divested after acquisition
- Generated record annual production of 38,523 Boe/d up 43% from 26,962 Boe/d in 2014
- Reduced production expenses, excluding ad valorem taxes, by 2% despite significant growth in our asset base
- Year-end proved reserves increased 18% to a record 164.2 MMBoe (97% PDP, 27% liquids)

Paul T. Horne, President and Chief Executive Officer of Legacy's general partner, commented, "Despite the challenging commodity price environment in 2015, I'm exceedingly proud of our team's accomplishments this year. We knew coming into the year that, should prices not improve, we were going to face significant headwinds. However, in light of these challenges, we were able to achieve several milestones. We made expense reduction a significant goal in 2015 and were able to reduce production expenses to a level below our 2014 costs, even when including recent acquisitions. From Q4 2014 to Q4 2015, excluding the effect of any acquisitions made during that time, we have reduced our production expenses (excluding taxes) by just over 23% which, quite frankly, I did not believe was possible. Our previously announced development agreement with an affiliate of TPG Special Situation Partners allowed us to monetize a portion of our undeveloped assets in the Permian. We have drilled and completed six wells under the agreement and are in the process of completing six more wells. Our drilling costs have outperformed expectations and we anticipate strong production results once all wells are completed. Our acquisitions of natural gas properties and related gathering and processing assets in East Texas have provided a significant entry into a new basin as well as exposure to a new cash flow stream. Our team has done a fantastic job integrating these assets and we look forward to the opportunity to pursue some accretive capital projects on these assets in 2016.

"We anticipate 2016 will be another challenging year. Commodity prices have remained depressed and have further deteriorated our cash-flow projections. As previously announced, we suspended distributions to our unitholders and our preferred unitholders in order to focus on our balance sheet, liquidity position and leverage metrics. We continue to work through select credit-accretive asset sales and other opportunities. As we have stated in the past, we strongly believe that today's current commodity price environment is unsustainable and believe our efforts in 2015 and our planned efforts in 2016 will best position us to capitalize when a recovery occurs."

Dan Westcott, Executive Vice President and Chief Financial Officer of Legacy's general partner, commented, "Though low commodity prices have persisted in our industry for the last 18 months, I'm proud of our results and efforts to date. We have been taking difficult, but important steps to improve our balance sheet position: cutting operation costs, suspending distributions and initiating credit-accretive asset sales. We also recently amended our revolving credit facility, providing greater flexibility under certain covenants to better weather this storm. In particular, we have modified our Secured Debt to EBITDA covenant to a 1st Lien Debt to EBITDA covenant that begins at 3.5x and tapers to 2.5x by Q3 2017 and have reduced our EBITDA to Interest Expense covenant to 2.0x beginning Q2 2016 through Q2 2017. As part of the amendment, we reduced our borrowing base to $725 million leaving us with $105.6 million of current availability. Based on current strip prices, we project we are slightly free cash flow positive in 2016 and we have sufficient liquidity for the year. We plan to use any asset sale proceeds to generate additional cash to reduce our total debt outstanding and improve our financial metrics."

Proved Reserves

The following information represents estimates of our proved reserves as of December 31, 2015 which have been prepared in compliance with the SEC rules and accounting standards using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month in the year ending December 31, 2015. Our average WTI price, as posted by Plains Marketing L.P., was $46.79 per Bbl for oil and our average natural gas price, as posted by Platts Gas Daily, was $2.59 per MMBtu. Our proved reserves by operating region as of December 31, 2015 are as follows:

Operating Regions	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBoe)	% Liquids	% PDP	% Total	Standardized Measure ($ thousands)(1)
Permian Basin	28,111	100,414	1,091	45,938	63.6 %	91.8 %	28.0 %	$ 361,514
East Texas	31	429,274	4	71,580	— %	97.9 %	43.6 %	211,220
Rocky Mountain	5,772	180,019	4,369	40,144	25.3 %	98.8 %	24.5 %	87,710
Mid-Continent	2,185	10,861	2,180	6,175	70.7 %	99.8 %	3.8 %	33,284
Other	44	1,065	107	329	45.9 %	100.0 %	0.1 %	1,213
Total	**36,143**	**721,633**	**7,751**	**164,166**	**26.7%**	**96.5%**	**100.0%**	**$ 694,941**

(1) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price) without giving effect to non-property related expenses such as general administrative expenses and debt service or to depletion, depreciation and amortization and discounted using an annual discount rate of 10%. For the purpose of calculating the standardized measure, the costs and prices are unescalated. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on its share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to derivative transactions.

2016 Capital Program By Category

	Percent of Total
Horizontal Permian Drilling	30%
East Texas (Workovers, G&P, Facilities)	30%
Other Workovers	20%
CO_2 + Other Facilities	20%
Total Capital Expenditures	100%
Total Capital Expenditures Dollars	$ 37,000

We do not maintain any long-term drilling contracts and serve as operator of approximately 90% of our anticipated capital program. Accordingly, we maintain significant control of the capital program budget and may deviate materially from the figures above based on market condition (or otherwise) with the overriding intent to deploy capital prudently. Should current commodity prices persist, we may reduce our capital program meaningfully to further our capital preservation efforts.

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended December 31, 2015	Three Months Ended December 31, 2014	Twelve Months Ended December 31, 2015	Twelve Months Ended December 31, 2014
	(In thousands, except per unit data)			
Revenues				
Oil sales	$ 40,653	$ 80,348	$ 199,841	$ 396,774
Natural gas liquids sales	3,778	8,002	16,645	27,483
Natural gas sales	35,510	31,256	122,293	108,042
Total revenues	$ 79,941	$ 119,606	$ 338,779	$ 532,299
Expenses:				
Oil and natural gas production	$ 48,436	$ 53,222	$ 183,163	$ 186,750
Ad valorem taxes	3,169	1,745	11,328	12,051
Total	$ 51,605	$ 54,967	$ 194,491	$ 198,801
Production and other taxes	$ 3,345	$ 7,242	$ 16,383	$ 31,534
General and administrative excluding LTIP & acquisition costs	$ 8,574	$ 8,164	$ 30,919	$ 29,760
Acquisition costs	743	95	8,919	5,425
LTIP expense (benefit)	1,689	(60)	6,673	3,795
Total general and administrative	$ 11,006	$ 8,199	$ 46,511	$ 38,980
Depletion, depreciation, amortization and accretion	$ 54,952	$ 53,436	$ 177,258	$ 173,686
Commodity derivative cash settlements:				
Oil derivative cash settlements received (paid)	$ 15,298	$ 9,609	$ 91,953	$ (5,431)
Natural gas derivative cash settlements received	13,314	5,031	40,972	8,097
Total commodity derivative cash settlements	$ 28,612	$ 14,640	$ 132,925	$ 2,666
Production:				
Oil (MBbls)	1,088	1,253	4,608	4,784
Natural gas liquids (MGal)	10,874	11,283	42,210	30,861
Natural gas (MMcf)	16,997	8,966	50,687	25,936
Total (MBoe)	4,180	3,016	14,061	9,841
Average daily production (Boe/d)	45,435	32,783	38,523	26,962
Average sales price per unit (excluding commodity derivative cash settlements):				
Oil price (per Bbl)	$ 37.36	$ 64.12	$ 43.37	$ 82.94
Natural gas liquids price (per Gal)	$ 0.35	$ 0.71	$ 0.39	$ 0.89
Natural gas price (per Mcf)(a)	$ 2.09	$ 3.49	$ 2.41	$ 4.17
Combined (per Boe)	$ 19.12	$ 39.66	$ 24.09	$ 54.09
Average sales price per unit (including commodity derivative cash settlements):				
Oil price (per Bbl)	$ 51.43	$ 71.79	$ 63.32	$ 81.80
Natural gas liquids price (per Gal)	$ 0.35	$ 0.71	$ 0.39	$ 0.89
Natural gas price (per Mcf)(a)	$ 2.87	$ 4.05	$ 3.22	$ 4.48
Combined (per Boe)	$ 25.97	$ 44.51	$ 33.55	$ 54.36
Average WTI oil spot price (per Bbl)	$ 42.07	$ 73.20	$ 48.81	$ 92.91
Average Henry Hub natural gas index price (per Mcf)	$ 2.23	$ 3.83	$ 2.63	$ 4.26
Average unit costs per Boe:				
Production costs, excluding production and other taxes	$ 11.59	$ 17.65	$ 13.03	$ 18.98
Ad valorem taxes	$ 0.76	$ 0.58	$ 0.81	$ 1.22
Production and other taxes	$ 0.80	$ 2.40	$ 1.17	$ 3.20
General and administrative excluding LTIP & acquisition costs	$ 2.05	$ 2.71	$ 2.20	$ 3.02
Total general and administrative	$ 2.63	$ 2.72	$ 3.31	$ 3.96
Depletion, depreciation, amortization and accretion	$ 13.15	$ 17.72	$ 12.61	$ 17.65

Annual Financial and Operating Results - 2015 Compared to 2014

- Production increased 43% to an annual record of 38,523 Boe/d from 26,962 Boe/d primarily due to $540.3 million of acquisitions in 2015 including our acquisition of various oil and natural gas properties and associated production assets from Anadarko E&P Onshore LLC ("Anadarko Acquisition") for a net purchase price of $335.5 million.

- Average realized price, excluding net cash settlements from commodity derivatives, decreased 55% to $24.09 per Boe in 2015 from $54.09 per Boe in 2014. Average realized oil price decreased 48% to $43.37 in 2015 from $82.94 in 2014. This decrease was primarily driven by a decrease in the average West Texas Intermediate ("WTI") crude oil price of $44.10 per Bbl partially offset by a decrease in realized differentials, primarily in the Permian Basin. Average natural gas price decreased 42% to $2.41 per Mcf in 2015 from $4.17 per Mcf in 2014. This decrease was primarily driven by a decrease in the average Henry Hub natural gas index price of $1.63 per Mcf. Finally, our average realized NGL price decreased 56% to $0.39 per gallon in 2015 from $0.89 per gallon in 2014.

- Production expenses, excluding ad valorem taxes, decreased 2% to $183.2 million in 2015 from $186.8 million in 2014 due to our cost containment efforts on our base assets, partially offset by costs associated with the Anadarko Acquisition and other recent acquisitions, as well as a full year of production costs on the properties acquired from WPX in June 2014. On an average cost per Boe basis, production expenses decreased 31% to $13.03 per Boe in 2015 from $18.98 per Boe in 2014, driven primarily by the inclusion of lower cost natural gas properties from the Anadarko and WPX acquisitions as well as a reduction in the production expenses from our base assets.

- Non-cash impairment expense totaled $633.8 million driven by the significant decline in oil and natural gas prices during 2015.

- General and administrative expenses, excluding acquisition costs and unit-based Long-Term Incentive Plan ("LTIP") compensation expense totaled $30.9 million in 2015 compared to $29.8 million in 2014. This increase was primarily attributable to a $1.9 million increase in salary and benefit expenses, net of overhead recovery, due to the hiring of 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 2015 were $132.9 million as compared to $2.7 million in 2014.

- Total development capital expenditures decreased to $36.8 million in 2015 from $133.4 million in 2014. During 2015 we entered into a Development Agreement (the "Development Agreement") with Jupiter JV, LP ("Investor"), which was formed by certain of TPG Special Situations Partners' investment funds. Under the Development Agreement, we drilled and completed 6 wells in 2015 and had another 6 wells in process at December 31, 2015. During 2015 we also incurred capital costs related to our CO_2 injection on properties acquired during 2014. Our non-operated capital expenditures were 22% of our total capital expenditures in 2015 as compared to 28% in 2014.

Financial and Operating Results - Fourth Quarter 2015 Compared to Fourth Quarter 2014

- Production increased 39% to 45,435 Boe/d from 32,783 Boe/d primarily due to the Anadarko Acquisition and other recent acquisitions.

- Average realized price, excluding net cash settlements from commodity derivatives, decreased 52% to $19.12 per Boe in 2015 from $39.66 per Boe in 2014. Average realized oil price decreased 42% to $37.36 per Bbl in 2015 from $64.12 per Bbl in 2014. This decrease of $26.76 was primarily attributable to the sharp decline in the average WTI crude oil price of $31.13 partially offset by lower realized regional differentials. Average realized natural gas prices declined 40% to $2.09 per Mcf in 2015 from $3.49 per Mcf in 2014. This decrease of $1.40 was primarily attributable to a $1.60 decline in the average Henry Hub natural gas price index partially offset by lower realized regional differentials. Finally, our average realized NGL price decreased 51% to $0.35 per gallon in 2015 from $0.71 per gallon in 2014.

- Production expenses, excluding ad valorem taxes, decreased 9% to $48.4 million in 2015 from $53.2 million in 2014. Production expenses decreased primarily due to cost reduction efforts on our historical properties partially offset by additional expenses on properties acquired in 2015. On a per Boe basis, production expenses decreased to $11.59 from $17.65 or 34% driven by acquisitions of properties with lower per Boe production expenses as well as cost reductions in our ongoing operations.

- Non-cash impairment expense totaled $326.3 million due to the significant decline of oil and natural gas prices during the period.

- General and administrative expenses, excluding acquisition costs and LTIP compensation expense, increased to $8.6 million in 2015 from $8.2 million in 2014. This increase was primarily attributable to an increase in salary and benefit expenses related to the hiring of additional personnel to manage our larger asset base partially offset by general cost reduction efforts.

- Cash settlements received on our commodity derivatives were $28.6 million during 2015 compared to $14.6 million in 2014, resulting from the continued decline in commodity prices during 2015.

- Total development capital expenditures were $7.2 million in the fourth quarter of 2015. Non-operated capital expenditures comprised 13% of our total capital expenditures during the period with activity primarily in the Permian.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of February 22, 2016, we had entered into derivative agreements to receive average NYMEX WTI crude oil prices and NYMEX Henry Hub, Waha, 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
2016	594,600	$68.37	$56.15 - $99.85
2017	182,500	$84.75	$84.75

WTI Crude Oil 3-Way Collars. As an illustrative example, at an annual average WTI market price of $35.00, the summary positions below would result in a net price of $60.00 for both 2016 and 2017.

Calendar Year	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
2016	621,300	$63.37	$88.37	$106.40
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 $35.00, the summary positions below would result in a net price of $66.70, $65.85 and $65.50, for 2016, 2017 and 2018, respectively.

Calendar Year	Volumes (Bbls)	Average Long Put Price per Bbl	Average Short Put Price per Bbl	Average Swap Price per Bbl
2016	183,000	$57.00	$82.00	$91.70
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
2016	2,928,000	$(1.60)	$(1.50) - $(1.75)
2017	2,190,000	$(0.30)	$(0.05) - $(0.75)

Natural Gas Swaps (Henry Hub, Waha and CIG-Rockies):

Calendar Year	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
2016	29,019,200	$3.40	$3.29 - $5.30
2017	27,600,000	$3.36	$3.29 - $3.39
2018	27,600,000	$3.36	$3.29 - $3.39
2019	25,800,000	$3.36	$3.29 - $3.39

Natural Gas 3-Way Collars (Henry Hub). As an illustrative example, at an annual average Henry Hub market price of $2.50, the summary positions below would result in a net price of $3.00 for both 2016 and 2017.

Calendar Year	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
2016	5,580,000	$3.75	$4.25	$5.08
2017	5,040,000	$3.75	$4.25	$5.53

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

	2016		2017	
	Volumes (MMBtu)	Average Price per MMBtu	Volumes (MMBtu)	Average Price per MMBtu
NWPL	14,977,818	$(0.19)	7,300,000	$(0.16)
SoCal	—	$—	2,500,250	$0.11
San Juan	2,499,780	$(0.16)	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 2015 Form 10-K which will be filed on or about February 26, 2016.

Conference Call

As announced on January 21, 2016, Legacy will host an investor conference call to discuss Legacy's results on Thursday, February 25, 2016 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 3, 2016, by dialing 855-859-2056 or 404-537-3406 and entering replay code 22745604. Those wishing to listen to the live or archived web cast 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 unitholders, just like unitholders of other master limited partnerships, are allocated taxable income irrespective of cash distributions paid.

This release is intended to be a qualified notice under Treasury Regulation Section 1.1446-4(b). Brokers and nominees should treat one hundred percent (100.0%) of Legacy's distributions to foreign investors as being attributable to income that is effectively connected with a United States trade or business. Accordingly, Legacy's distributions to foreign investors are subject to federal income tax withholding at the highest applicable rate.

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,	
	2015	2014	2015	2014
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 40,653	$ 80,348	$ 199,841	$ 396,774
Natural gas liquids (NGL) sales	3,778	8,002	16,645	27,483
Natural gas sales	35,510	31,256	122,293	108,042
Total revenues	79,941	119,606	338,779	532,299
Expenses:				
Oil and natural gas production	51,605	54,967	194,491	198,801
Production and other taxes	3,345	7,242	16,383	31,534
General and administrative	11,006	8,199	46,511	38,980
Depletion, depreciation, amortization and accretion	54,952	53,436	177,258	173,686
Impairment of long-lived assets	326,349	440,130	633,805	448,714
(Gain) loss on disposal of assets	(5,539)	756	(3,972)	(2,479)
Total expenses	441,718	564,730	1,064,476	889,236
Operating income (loss)	(361,777)	(445,124)	(725,697)	(356,937)
Other income (expense):				
Interest income	2	211	329	873
Interest expense	(17,988)	(17,971)	(76,891)	(67,218)
Equity in income of equity method investees	29	119	126	428
Net gains (losses) on commodity derivatives	34,270	129,417	98,253	138,092
Other	120	120	841	258
Income (loss) before income taxes	(345,344)	(333,228)	(703,039)	(284,504)
Income tax (expense) benefit	1,208	1,729	1,498	859
Net income (loss)	$ (344,136)	$ (331,499)	$ (701,541)	$ (283,645)
Distributions to preferred unitholders	(4,750)	(4,750)	(19,000)	(11,694)
Net income (loss) attributable to unitholders	$ (348,886)	$ (336,249)	$ (720,541)	$ (295,339)
Income (loss) per unit — basic and diluted	$ (5.06)	$ (4.94)	$ (10.45)	$ (4.92)
Weighted average number of units used in computing income (loss) per unit —				
Basic	68,950	68,035	68,928	60,053
Diluted	68,950	68,035	68,928	60,053

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

	December 31, 2015	December 31, 2014
	(In thousands)	
ASSETS		
Current assets:		
Cash	$ 2,006	$ 725
Accounts receivable, net:		
Oil and natural gas	33,944	49,390
Joint interest owners	25,378	16,235
Other	86	237
Fair value of derivatives	63,711	120,305
Prepaid expenses and other current assets	4,334	5,362
Total current assets	129,459	192,254
Oil and natural gas properties, at cost:		
Proved oil and natural gas properties using the successful efforts method of accounting	3,485,634	2,946,820
Unproved properties	13,424	47,613
Accumulated depletion, depreciation, amortization and impairment	(2,090,102)	(1,354,459)
	1,408,956	1,639,974
Other property and equipment, net of accumulated depreciation and amortization of $8,915 and $7,446, respectively	4,575	3,767
Operating rights, net of amortization of $4,953 and $4,509, respectively	2,064	2,508
Fair value of derivatives	56,373	32,794
Other assets, net of amortization of $15,563 and $12,551, respectively	23,829	24,255
Investments in equity method investees	646	3,054
Total assets	$1,625,902	$1,898,606
LIABILITIES AND PARTNERS' EQUITY		
Current liabilities:		
Accounts payable	$ 13,581	$ 2,787
Accrued oil and natural gas liabilities	50,573	78,615
Fair value of derivatives	2,019	2,080
Asset retirement obligation	3,496	3,028
Other	11,424	11,066
Total current liabilities	81,093	97,576
Long-term debt	1,440,396	938,876
Asset retirement obligation	282,909	223,497
Fair value of derivatives	—	—
Other long-term liabilities	1,181	1,452
Total liabilities	1,805,579	1,261,401
Commitments and contingencies		
Partners' equity:		
Series A Preferred equity - 2,300,000 units issued and outstanding at December 31, 2015 and December 31, 2014	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at December 31, 2015 and December 31, 2014	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at December 31, 2015 and December 31, 2014	30,814	30,814
Limited partners' equity (deficit) - 68,949,961 and 68,910,784 units issued and outstanding at December 31, 2015 and 2014, respectively	(439,811)	376,885
General partner's equity (deficit) (approximately 0.03%)	(133)	53
Total partners' equity	(179,677)	637,205
Total liabilities and partners' equity	$1,625,902	$1,898,606

Non-GAAP Financial Measures

This press release, the financial tables and other supplemental information include "Adjusted EBITDA" and "Distributable Cash Flow", both of which are non-generally accepted accounting principles ("non-GAAP") measures which may be used periodically by management when discussing our financial results with investors and analysts. The following presents a reconciliation of each of these non-GAAP financial measures to their nearest comparable generally accepted accounting principles ("GAAP") measure.

Adjusted EBITDA and Distributable Cash Flow are presented as management believes they provide additional information concerning the performance of our business and are 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 and Distributable Cash Flow 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.

Distributable Cash Flow is one of the factors used by the board of directors of our general partner (the “Board”) to help determine the amount of Available Cash as defined in our partnership agreement, that is to be distributed to our unitholders for such period. Under our partnership agreement, Available Cash is defined generally to mean, cash on hand at the end of each quarter, plus working capital borrowings made after the end of the quarter, less cash reserves determined by our general partner. The Board determines whether to increase, maintain or decrease the current level of distributions in accordance with the provisions of our partnership agreement based on a variety of factors, including without limitation, Distributable Cash Flow, cash reserves established in prior periods, reserves established for future periods, borrowing capacity for working capital, temporary, one-time or uncharacteristic historical results, and forecasts of future period results including the impact of pending acquisitions. Management and the Board consider the long-term view of expected results in determining the amount of its distributions. Certain factors impacting Adjusted EBITDA and Distributable Cash Flow 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 historically has not varied the distribution it declares based on such timing effects.

"Adjusted EBITDA" and "Distributable Cash Flow" should not be considered as alternatives 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 taxes;
- 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.

Distributable Cash Flow is defined as Adjusted EBITDA less:

- Cash interest expense including the accrual of interest expense related to our senior notes which is paid on a semi-annual basis;
- Cash income taxes;
- Cash settlements of LTIP unit awards;
- Estimated maintenance capital expenditures; and
- Distributions on Series A and Series B preferred units.

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

	Three Months Ended December 31,		Twelve Months Ended December 31,	
	2015	2014	2015	2014
	(In thousands)			
Net loss	$ (344,136)	$ (331,499)	$ (701,541)	$ (283,645)
Plus:				
Interest expense	17,988	17,971	76,891	67,218
Income tax expense (benefit)	(1,208)	(1,729)	(1,498)	(859)
Depletion, depreciation, amortization and accretion	54,952	53,436	177,258	173,686
Impairment of long-lived assets	326,349	440,130	633,805	448,714
(Gain) loss on disposal of assets	(5,539)	756	(3,972)	(2,479)
Equity in income of equity method investees	(29)	(119)	(126)	(428)
Unit-based compensation expense (benefit)	1,688	(60)	6,673	3,795
Minimum payments received in excess of overriding royalty interest earned(1)	—	358	1,130	1,381
Equity in EBITDA of equity method investee(2)	—	156	169	805
Net gains on commodity derivatives	(34,270)	(129,417)	(98,253)	(138,092)
Net cash settlements received on commodity derivatives	28,612	14,640	132,925	2,666
Transaction related expenses	743	95	8,919	5,425
Adjusted EBITDA	$ 45,150	$ 64,718	$ 232,380	$ 278,187
Less:				
Cash interest expense	20,295	17,597	72,919	65,236
Cash settlements of LTIP unit awards	—	1	—	772
Estimated maintenance capital expenditures(3)	NM*	18,200	NM*	72,400
Development capital expenditures(4)	7,179	NM*	36,842	NM*
Distributions on Series A and Series B preferred units	4,750	4,750	19,000	11,694
Distributable Cash Flow(3)	$ 12,926	$ 24,170	$ 103,619	$ 128,085
Distributions Attributable to Each Period(5)	$ —	$ 42,208	$ 58,957	$ 153,829
Distribution Coverage Ratio(3)(6)	N/A	0.57x	1.76x	0.83x

(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.

(3) Estimated maintenance capital expenditures are intended to represent the amount of capital required to fully offset declines in production, but do not target specific levels of proved reserves to be achieved. Estimated maintenance capital expenditures do not include the cost of new oil and natural gas reserve acquisitions, but rather the costs associated with converting proved developed non-producing, proved undeveloped and unproved reserves to proved developed producing reserves. These costs, which are incorporated in our annual capital budget as approved by the Board, include development drilling, recompletions, workovers and various other procedures to generate new or improve existing production on both operated and non-operated properties. Estimated maintenance capital expenditures are based on management's judgment of various factors including the long-term (generally 5-10 years) decline rate of our current production and the projected productivity of our total development capital expenditures. Actual production decline rates and capital efficiency may materially differ from our projections and such estimated maintenance capital expenditures may not maintain our production. Further, because estimated maintenance capital expenditures are not intended to target specific levels of reserves, if we do not acquire new proved or unproved reserves, our total reserves will decrease over time and we would be unable to sustain production at current levels, which could adversely affect our ability to pay a distribution at the current level or at all.

(4) Represents total capital expenditures for the development of oil and natural gas properties as presented on an accrual basis. For 2016, we intend to fund our total oil and natural gas development program from net cash provided by operating activities. Previously, we intended to fund only a portion of our oil and natural gas development program from net cash provided by operating activities.

(5) Represents the aggregate cash distributions declared for the respective period and paid by Legacy to our unitholders within 45 days after the end of each quarter within such period.

(6) We refer to the ratio of Distributable Cash Flow over Distributions Attributable to Each Period ("Available Cash" available for distribution to our unitholders per our partnership agreement) as "Distribution Coverage Ratio." If the Distribution Coverage Ratio is equal to or greater than 1.0x, then our cash flows are sufficient to cover our quarterly distributions to our unitholders with respect to such period. If the Distribution Coverage Ratio is less than 1.0x, then our cash flows with respect to such period were not sufficient to cover our quarterly distributions to our unitholders and we must borrow funds or use cash reserves established in prior periods to cover our quarterly distributions to our unitholders. The Board uses its discretion in determining if such shortfalls are temporary or if distributions should be adjusted downward.

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