Legacy Reserves LP Announces Second Quarter 2015 Results

MIDLAND, Texas, August 5, 2015- (GLOBENEWSWIRE) -- Legacy Reserves LP ("Legacy") (NASDAQ:LGCY) today announced second quarter results for 2015.

Q2 highlights include:

- Production of 33,571 Boe/d
- Lease operating expense (excluding ad valorem taxes) of $42.8 million, a $3.1 million (6.8%) improvement relative to Q1 2015 and a $10.4 million (19.5%) improvement relative to Q4 2014
- Adjusted EBITDA of $69.9 million, an $8.0 million (12.8%) improvement relative to Q1 2015 on a net loss of approximately $38.5 million
- Distributable Cash Flow of $39.8 million, a $13.0 million (48.5%) improvement relative to Q1 2015, covering our quarterly distribution by 1.64 times

Paul T. Horne, President and Chief Executive Officer of Legacy commented, "The Legacy team did an outstanding job in Q2. By all accounts, our folks delivered their numbers. We realized an approximate 7% decline in LOE relative to Q1 and 20% relative to Q4 2014, all while holding production relatively flat over that period. As a company we are excelling in nearly all areas we control and for that I am extremely proud. We remain excited about our recently-announced East Texas acquisitions, which closed on July 31. We are currently integrating those assets and building our team to take on those assets. We are also excited to have spudded the first well under our Joint Development Agreement with TPG Special Situations Partners and are bringing in our second and third rigs for those operations in the coming days. In spite of our great execution, we are cognizant of the incredibly challenging market environment. We will continue to watch commodity prices and, given our lack of meaningful operational commitments, can remain flexible to respond as needed in the future. We remain focused on creating value for our unitholders and positioning ourselves for the future."

Dan Westcott, Executive Vice President and Chief Financial Officer of Legacy commented, "I am really pleased with our Q2 results. Our team is giving their all and it shows throughout our financials. In addition to the lower costs and flat production, we posted record quarterly distribution coverage of 1.64 times. Regarding our balance sheet, in conjunction with our East Texas acquisitions, our bank group increased our borrowing base from $700 million to $950 million. Today we have approximately $396 million of availability under our revolver which we believe leaves us ample room for our business. Our banks have been valuable partners throughout our history and we appreciate their continued efforts and support. We have already added hedges to cover the production from the East Texas assets and will continue to monitor commodity futures prices to add additional hedges as warranted. In spite of the drop in commodity prices, we expect to achieve our 1.3 times 2015 distribution coverage goal stated earlier this year with the second half averaging nearly 1.2 times. Our $850 million of long-term capital raised in 2014 will prove helpful in this difficult environment as we continue to try to balance prudent protection with pragmatic progress."

LEGACY RESERVES LP
SELECTED FINANCIAL AND OPERATING DATA

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 59,113	$ 108,731	$ 109,409	$ 210,786
Natural gas liquids sales	5,729	5,103	9,921	9,069
Natural gas sales	22,959	23,280	50,010	43,163
Total revenue	$ 87,801	$ 137,114	$ 169,340	$ 263,018
Expenses:				
Oil and natural gas production, excluding ad valorem taxes	$ 42,828	$ 42,056	$ 88,772	$ 81,694
Ad valorem taxes	$ 2,392	$ 3,753	$ 5,668	$ 6,649
Total oil and natural gas production	$ 45,220	$ 45,809	$ 94,440	$ 88,343
Production and other taxes	$ 3,986	$ 8,595	$ 8,204	$ 16,550
General and administrative, excluding LTIP	$ 8,197	$ 12,669	$ 15,978	$ 19,626
LTIP expense	$ 2,193	$ 2,140	$ 3,281	$ 2,830
Total general and administrative	$ 10,390	$ 14,809	$ 19,259	$ 22,456
Depletion, depreciation, amortization and accretion	$ 36,197	$ 38,537	$ 77,265	$ 72,234
Commodity derivative cash settlements:				
Oil derivative cash settlements received (paid)	$ 27,364	$ (6,244)	$ 59,564	$ (8,800)
Natural gas derivative cash settlements received (paid)	$ 9,825	$ 234	$ 17,962	$ (820)
Production:				
Oil (MBbls)	1,171	1,175	2,371	2,310
Natural gas liquids (MGal)	11,566	5,519	21,252	8,881
Natural gas (MMcf)	9,649	4,877	19,307	8,102
Total (MBoe)	3,055	2,119	6,095	3,872
Average daily production (Boe/d)	33,571	23,286	33,674	21,392
Average sales price per unit (excluding derivative cash settlements):				
Oil price (per Bbl)	$ 50.48	$ 92.54	$ 46.14	$ 91.25
Natural gas liquids price (per Gal)	$ 0.50	$ 0.92	$ 0.47	$ 1.02
Natural gas price (per Mcf)	$ 2.38	$ 4.77	$ 2.59	$ 5.33
Combined (per Boe)	$ 28.74	$ 64.71	$ 27.78	$ 67.93
Average sales price per unit (including derivative cash settlements):				
Oil price (per Bbl)	$ 73.85	$ 87.22	$ 71.27	$ 87.44
Natural gas liquids price (per Gal)	$ 0.50	$ 0.92	$ 0.47	$ 1.02
Natural gas price (per Mcf)	$ 3.40	$ 4.82	$ 3.52	$ 5.23
Combined (per Boe)	$ 40.91	$ 61.87	$ 40.50	$ 65.44
Average WTI oil spot price (per Bbl)	$ 57.95	$ 103.35	$ 53.34	$ 101.05
Average Henry Hub natural gas index price (per Mcf)	$ 2.74	$ 4.68	$ 2.77	$ 4.81
Average unit costs per Boe:				
Oil and natural gas production	$ 14.02	$ 19.85	$ 14.56	$ 21.10
Ad valorem taxes	$ 0.78	$ 1.77	$ 0.93	$ 1.72
Production and other taxes	$ 1.30	$ 4.06	$ 1.35	$ 4.27
General and administrative excluding LTIP	$ 2.68	$ 5.98	$ 2.62	$ 5.07
Total general and administrative	$ 3.40	$ 6.99	$ 3.16	$ 5.80
Depletion, depreciation, amortization and accretion	$ 11.85	$ 18.19	$ 12.68	$ 18.66

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

- Production increased 44% to 33,571 Boe/d from 23,286 Boe/d primarily due to our 2014 acquisitions including our Piceance Basin acquisition from WPX Energy, Inc. ("WPX Acquisition").
- Average realized price, excluding net cash settlements from commodity derivatives, decreased 56% to $28.74 per Boe in 2015 from $64.71 per Boe in 2014 driven by the significant decline in commodity prices as well as the increase of NGL and natural gas production as a percentage of total production. Average realized oil price decreased 45% to $50.48 in 2015 from $92.54 in 2014 driven by a decrease in the average West Texas Intermediate ("WTI") crude oil price of $45.40 per Bbl partially offset by a decrease in realized regional differentials. Average realized natural gas price decreased 50% to $2.38 per Mcf in 2015 from $4.77 per Mcf in 2014. This decrease is a result of the decrease in the average Henry Hub natural gas index price of approximately $1.94 per Mcf as well as the inclusion of lower priced natural gas production from the WPX Acquisition. Finally, our average realized NGL price decreased 46% to $0.50 per gallon in 2015 from $0.92 per gallon in 2014. This decrease is due to the combination of lower commodity prices and the inclusion of lower priced NGL production from the WPX Acquisition.
- Production expenses, excluding ad valorem taxes, increased 2% to $42.8 million in 2015 from $42.1 million in 2014. On an average cost per Boe basis, production expenses decreased 29% to $14.02 per Boe in 2015 from $19.85 per Boe in 2014, driven primarily by expense reduction efforts across the properties that we have owned prior to the WPX Acquisition as well as the inclusion of lower cost natural gas properties acquired in the WPX Acquisition.
- General and administrative expenses, excluding unit-based Long-Term Incentive Plan ("LTIP") compensation expense totaled $8.2 million in 2015 compared to $12.7 million in 2014. This decrease was primarily due to a $3.2 million decrease in acquisition costs between the periods as we incurred approximately $4.8 million of one-time acquisition related expenses during Q2 2014 associated with the WPX Acquisition and the remainder attributable to overall general and administrative expense reduction efforts.
- Cash settlements received on our commodity derivatives during 2015 were $37.2 million compared to cash settlements paid of approximately $6.0 million in 2014.
- Total development capital expenditures decreased to $8.4 million in 2015 from $36.1 million in 2014. The 2015 activity was comprised mainly of the drilling and completion of a non-operated horizontal Bone Springs well, completion costs on an operated horizontal Bone Springs well and capital costs related to CO_2 properties. Our non-operated capital expenditures were 51% of total capital for the quarter compared to 14% in 2014.

Financial and Operating Results - Second Quarter Year to Date 2015 Compared to Second Quarter Year to Date 2014

- Production increased 57% to 33,674 Boe/d from 21,392 Boe/d primarily due to acquisitions in 2014 including the WPX Acquisition.
- Average realized price, excluding net cash settlements from commodity derivatives, decreased 59% to $27.78 per Boe in 2015 from $67.93 per Boe in 2014 driven by the significant decline in commodity prices as well as the increase in NGL and natural gas production as a percentage of total production. Average realized oil price decreased 49% to $46.14 in 2015 from $91.25 in 2014 driven by a decrease in the average WTI crude oil price of $47.71 per Bbl partially offset by a decrease in realized regional differentials. Average realized natural gas price decreased 51% to $2.59 per Mcf in 2015 from $5.33 per Mcf in 2014. This decrease is a result of the decrease in the average Henry Hub natural gas index price of approximately $2.04 per Mcf as well as the inclusion of lower priced natural gas production from the WPX Acquisition. Finally, our average realized NGL price decreased 54% to $0.47 per gallon in 2015 from $1.02 per gallon in 2014. This decrease is due to the combination of lower commodity prices and the inclusion of lower priced NGL production from the WPX Acquisition.
- Production expenses, excluding ad valorem taxes, increased 9% to $88.8 million in 2015 from $81.7 million in 2014. On an average cost per Boe basis, production expenses decreased 31% to $14.56 per Boe in 2015 from $21.10 per Boe in 2014, driven primarily by expense reduction efforts across the properties that we have owned prior to the WPX Acquisition as well as the inclusion of lower cost natural gas properties acquired in the WPX Acquisition.
- Non-cash impairment expense totaled $209.4 million driven by the significant decline in natural gas futures prices during the first quarter of 2015.
- General and administrative expenses, excluding unit-based LTIP compensation expense totaled $16.0 million in 2015 compared to $19.6 million in 2014. This decrease was primarily due to a $3.2 million decrease in acquisition costs between the periods as we incurred approximately $4.8 million of one-time acquisition related expenses during Q2 2014 associated with the WPX Acquisition and the remainder attributable to overall general and administrative expense reduction efforts.
- Cash settlements received on our commodity derivatives during 2015 were $77.5 million compared to cash settlements paid of approximately $9.6 million in 2014.
- Total development capital expenditures decreased to $21.8 million in 2015 from $57.9 million in 2014. The 2015 activity was comprised mainly of the drilling and completion of two horizontal Wolfcamp wells, completion costs on an operated horizontal Bone Springs well, drilling and completion costs on a non-operated horizontal Bone Springs well and capital costs related to CO_2 properties. Our non-operated capital expenditures were 20% of total capital for the quarter compared to 23% in 2014.

Commodity Derivative Contracts

We enter into oil and natural gas derivative contracts to help mitigate the risk of changing commodity prices. As of August 5, 2015, we had entered into derivative agreements to receive average NYMEX WTI crude oil prices and NYMEX Henry Hub, Waha, NWPL, NGPA, SoCal, San Juan and CIG-Rockies natural gas prices as summarized below:

WTI Crude Oil Swaps:

Time Period	Volumes (Bbls)	Average Price per Bbl	Price Range per Bbl
July-December 2015	282,522	$79.51	$52.00 - $99.85
2016	228,600	$87.94	$86.30 - $99.85
2017	182,500	$84.75	$84.75

WTI Crude Oil 3-Way Collars:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Long Put Price per Bbl	Average Short Call Price per Bbl
July-December 2015	673,440	$64.78	$89.78	$110.57
2016	621,300	$63.37	$88.37	$106.40
2017	72,400	$60.00	$85.00	$104.20

WTI Crude Oil Enhanced Swaps:

Time Period	Volumes (Bbls)	Average Short Put Price per Bbl	Average Swap Price per Bbl
July-December 2015	506,000	$77.73	$93.98

Time Period	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
July-December 2015	1,656,000	$(1.78)	$(1.75) - $(1.90)
2016	2,928,000	$(1.60)	$(1.50) - $(1.75)
2017	730,000	$(0.75)	$(0.75)

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

Time Period	Volumes (MMBtu)	Average Price per MMBtu	Price Range per MMBtu
July-December 2015	13,706,400	$4.01	$3.11 - $5.82
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):

Time Period	Volumes (MMBtu)	Average Short Put Price per MMBtu	Average Long Put Price per MMBtu	Average Short Call Price per MMBtu
July-December 2015	4,020,000	$3.66	$4.21	$5.01
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, NGPA, SoCal, San Juan and Waha):

	April-December 2015	
	Volumes (MMBtu)	Average Price per MMBtu
NWPL	6,000,000	$(0.13)
NGPL	240,000	$(0.15)
SoCal	120,000	$0.19
San Juan	240,000	$(0.12)
WAHA	3,000,000	$(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 7, 2015.

Conference Call

As announced on July 21, 2015, Legacy will host an investor conference call to discuss Legacy's results on Thursday, August 6, 2015 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 13, 2015, by dialing 855-859-2056 or 404-537-3406 and entering replay code 87656715. 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.

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,	
	2015	2014	2015	2014
	(In thousands, except per unit data)			
Revenues:				
Oil sales	$ 59,113	$ 108,731	$ 109,409	$ 210,786
Natural gas liquids (NGL) sales	5,729	5,103	9,921	9,069
Natural gas sales	22,959	23,280	50,010	43,163
Total revenues	87,801	137,114	169,340	263,018
Expenses:				
Oil and natural gas production	45,220	45,809	94,440	88,343
Production and other taxes	3,986	8,595	8,204	16,550
General and administrative	10,390	14,809	19,259	22,456
Depletion, depreciation, amortization and accretion	36,197	38,537	77,265	72,234
Impairment of long-lived assets	—	2,387	209,402	3,798
Loss on disposal of assets	(934)	(3,853)	1,007	(1,552)
Total expenses	94,859	106,284	409,577	201,829
Operating income (loss)	(7,058)	30,830	(240,237)	61,189
Other income (expense):				
Interest income	176	216	382	439
Interest expense	(17,760)	(16,225)	(35,552)	(30,164)
Equity in income of equity method investees	24	191	103	183
Net gains (losses) on commodity derivatives	(13,497)	(31,433)	6,983	(47,319)
Other	97	211	702	304
Loss before income taxes	(38,018)	(16,210)	(267,619)	(15,368)
Income tax (expense) benefit	(456)	(278)	291	(592)
Net loss	$ (38,474)	$ (16,488)	$ (267,328)	$ (15,960)
Distributions to Preferred unitholders	(4,750)	(2,194)	(9,500)	(2,194)
Net loss attributable to unitholders	$ (43,224)	$ (18,682)	$ (276,828)	$ (18,154)
Loss per unit - basic and diluted	$ (0.63)	$ (0.33)	$ (4.02)	$ (0.32)
Weighted average number of units used in computing net loss per unit -				
Basic	68,897	57,372	68,909	57,341
Diluted	68,897	57,372	68,909	57,341

LEGACY RESERVES LP
CONDENSED CONSOLIDATED BALANCE SHEETS
(UNAUDITED)

ASSETS

	June 30, 2015	December 31, 2014
	(In thousands)	
Current assets:		
Cash	$ 3,661	$ 725
Accounts receivable, net:		
Oil and natural gas	41,235	49,390
Joint interest owners	12,424	16,235
Other	254	237
Fair value of derivatives	63,951	120,305
Prepaid expenses and other current assets	5,708	5,362
Total current assets	127,233	192,254
Oil and natural gas properties using the successful efforts method, at cost:		
Proved properties	2,976,550	2,946,820
Unproved properties	48,322	47,613
Accumulated depletion, depreciation, amortization and impairment	(1,626,689)	(1,354,459)
	1,398,183	1,639,974
Other property and equipment, net of accumulated depreciation and amortization of $8,126 and $7,446, respectively	3,269	3,767
Operating rights, net of amortization of $4,731 and $4,509, respectively	2,286	2,508
Fair value of derivatives	18,605	32,794
Other assets, net of amortization of $13,996 and $12,551, respectively	24,179	24,255
Investments in equity method investees	624	3,054
Total assets	$ 1,574,379	$ 1,898,606

LIABILITIES AND PARTNERS' EQUITY

	June 30, 2015	December 31, 2014
Current liabilities:		
Accounts payable	$ 1,416	$ 2,787
Accrued oil and natural gas liabilities	54,667	78,615
Fair value of derivatives	985	2,080
Asset retirement obligation	3,028	3,028
Other	9,757	11,066
Total current liabilities	69,853	97,576
Long-term debt	966,111	938,876
Asset retirement obligation	241,611	223,497
Other long-term liabilities	1,294	1,452
Total liabilities	1,278,869	1,261,401
Commitments and contingencies		
Partners' equity		
Series A Preferred equity - 2,300,000 units issued and outstanding at June 30, 2015 and December 31, 2014	55,192	55,192
Series B Preferred equity - 7,200,000 units issued and outstanding at June 30, 2015 and December 31, 2014	174,261	174,261
Incentive distribution equity - 100,000 units issued and outstanding at June 30, 2015 and December 31, 2014	30,814	30,814
Limited partners' equity - 68,944,825 and 68,910,784 units issued and outstanding at June 30, 2015 and December 31, 2014, respectively	35,261	376,885
General partner's equity (approximately 0.03%)	(18)	53
Total partners' equity	295,510	637,205
Total liabilities and partners' equity	$ 1,574,379	$ 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.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(In thousands)			
Net income (loss)	$ (38,474)	$ (16,488)	$ (267,328)	$ (15,960)
Plus:				
Interest expense	17,760	16,225	35,552	30,164
Income tax expense (benefit)	456	278	(291)	592
Depletion, depreciation, amortization and accretion	36,197	38,537	77,265	72,234
Impairment of long-lived assets	—	2,387	209,402	3,798
(Gain) loss on disposal of assets	(934)	(3,853)	1,007	(1,552)
Equity in income of equity method investees	(24)	(191)	(103)	(183)
Unit-based compensation expense	2,193	2,140	3,281	2,830
Minimum payments received in excess of overriding royalty interest earned(1)	377	341	744	673
Equity in EBITDA of equity method investee(2)	50	241	169	499
Net (gains) losses on commodity derivatives	13,497	31,433	(6,983)	47,319
Net cash settlements received (paid) on commodity derivatives	37,189	(6,010)	77,526	(9,620)
Transaction expenses related to acquisitions	1,648	4,911	1,673	4,966
Adjusted EBITDA	$ 69,935	$ 69,951	$ 131,914	$ 135,760
Less:				
Cash interest expense	16,950	15,590	33,992	29,183
Cash settlements of LTIP unit awards	—	560	—	685
Estimated maintenance capital expenditures(3)	NM*	18,200	NM*	36,000
Development capital expenditures(4)	8,415	NM*	21,781	NM*
Distributions on Series A and Series B preferred units	4,750	2,193	9,500	2,193
Distributable Cash Flow(3)	$ 39,820	$ 33,408	$ 66,641	$ 67,699
Distributions Attributable to Each Period(5)	$ 24,309	$ 35,178	$ 48,532	$ 69,429
Distribution Coverage Ratio(3)(6)	1.64x	0.95x	1.37x	0.98x

* Not meaningful due to the 2015 change in presentation

(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.

(2) Equity in EBITDA of 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.

(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 2015, 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.

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