Rice Energy Reports Fourth Quarter and Full-Year 2015 Results

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CANONSBURG, Pa., Feb. 24, 2016 /PRNewswire/ -- **Rice Energy Inc.** (NYSE: RICE) ("Rice Energy") today reported fourth quarter and full-year 2015 financial and operational results. Highlights to date include:

- Fourth quarter net production averaged 624 MMcfe/d, 57% higher than fourth quarter 2014
- Adjusted EBITDAX(1) of $132.2 million for the fourth quarter, a 51% increase above fourth quarter 2014
- 2015 net production averaged 552 MMcfe/d, 101% higher than pro forma 2014 volumes and 5% above the high end of guidance
- $431.5 million adjusted EBITDAX for 2015, a 75% increase above pro forma 2014
- Adjusted realized natural gas price(2) of $3.39 and $3.19 per Mcf in the fourth quarter and full-year 2015, respectively
- Average gathering throughput of 1,026 MDth/d for the fourth quarter, a 74% increase relative to fourth quarter 2014
- Year-end 2015 proved reserves of 1.7 Tcfe, a 30% increase above the prior year
- Proved reserves PV-10(1) of $1.4 billion at strip pricing, including $265 million of hedge value
- Renegotiated third party gas gathering agreement for Western Greene County, PA acreage to increase dedication to Rice Midstream Partners (NYSE:RMP) by 19,000 gross acres
- Formed Strike Force Midstream LLC with Gulfport Energy (NASDAQ:GPOR) ("GPOR"), a Utica Shale midstream joint venture in Ohio to develop gas gathering and compression assets
- Closed strategic $375 million midstream equity investment by EIG Global Energy Partners
- Year-end liquidity of $1.4 billion(3)(4) and leverage of 2.1x(1)(4)

Commenting on the results, Daniel J. Rice IV, Chief Executive Officer, said, "Our 2015 accomplishments highlight our unique asset quality, differentiated technical approach and our financial strength. Our core position within the most productive and economic windows of the Marcellus and Utica Shales provides a solid foundation that is supported by a balanced firm transportation portfolio and systematic hedging strategy to continue economically growing our business including expanding our world-class midstream assets. Our strategy continues to be focused on protecting the balance sheet while generating the highest return on investments to drive long-term value creation for our shareholders."

1. Please see "Supplemental Non-GAAP Financial Measure" for a description of Adjusted EBITDAX, PV-10, and Further Adjusted EBITDAX.
2. Adjusted realized price includes our firm transportation sales, net, and the impact of hedging.
3. Excludes Rice Midstream Partners LP.
4. Pro forma for the $375 million preferred equity investment that closed February 22, 2016.

2015 Consolidated Results	**Three Months Ended December 31, 2015**		**Year Ended December 31, 2015**	
Total production (MMcfe)	57,399		201,328	
Total production (MMcfe/d)	624		552	
% Gas	100	%	99	%
% Operated	94	%	93	%
% Marcellus	72	%	74	%
Average realized prices per Mcf:				
Natural gas price before effects of hedges	$ 2.05		$ 2.21	
Natural gas price after effects of hedges(1)	$ 3.39		$ 3.18	
Adjusted realized price	$ 3.39		$ 3.19	

Average oil and NGL price per Bbl	$ 23.64		$ 21.79	
Average costs per Mcfe:				
Lease operating	$ 0.16		$ 0.22	
Gathering, compression and transportation	$ 0.51		$ 0.42	
Production taxes and impact fees	$ 0.04		$ 0.04	
General and administrative[2]	$ 0.43		$ 0.43	
Depreciation, depletion and amortization	$ 1.65		$ 1.60	
Adjusted EBITDAX (in thousands)	$ 132,153		$ 431,510	
Total midstream throughput (MDth/d)	1,026		894	
% Third-party	25	%	22	%

Fourth Quarter 2015 Financial Results

During the fourth quarter, our net daily production averaged 624 MMcfe/d (100% natural gas), a 57% increase relative to fourth quarter 2014 production. This quarterly production growth was primarily driven by improved well performance and wells online ahead of schedule.

Fourth quarter average realized natural gas price, before the effect of hedges, was $2.05 per Mcf. After giving effect to hedges, our average natural gas price was $3.39 per Mcf. Approximately 91% of our fourth quarter production received favorable Gulf Coast, TCO and Midwest pricing, as compared to 76% of third quarter 2015 production, due to increasing premium market exposure through our firm transportation portfolio. Our average basis differential for the quarter was ($0.14) per MMBtu, while TETCO M2 and Dominion South averaged ($0.93) and ($0.92) per MMBtu, respectively, below NYMEX Henry Hub for the quarter.

Per unit cash production costs (lease operating; gathering, compression and transportation; and production taxes and impact fees) were $0.71 per Mcfe. Adjusted EBITDAX for the quarter was $132.2 million. We reported adjusted net income[3] of $22.0 million, or $0.16 per share, after excluding unrealized gains on derivative contracts and other non-recurring income and expense items.

1. The effect of hedges includes realized gains and losses on commodity derivative transactions.
2. Excludes equity compensation expense of $0.08 per Mcfe for the three and twelve months ended December 31, 2015.
3. Please see "Supplemental Non-GAAP Financial Measure" for a description of Adjusted Net Income.

Full Year 2015 Financial Results

Net production averaged 552 MMcfe/d, a 101% increase as compared to pro forma 2014. Our 2015 average realized natural gas price, before the effect of hedges, was $2.21 per Mcf. After giving effect to hedges, our average natural gas price was $3.18 per Mcf. The average adjusted realized price was $3.19 per Mcf. Per unit cash production costs were $0.68 per Mcfe. Adjusted EBITDAX during 2015 was $431.5 million. We reported adjusted net income of $0.8 million, or $0.01 per share.

During 2015, we invested $625 million to drill and complete Marcellus and Utica wells and invested $115 million in land activity. Additionally, we invested $248 million for our retained midstream assets.

Financial Position and Liquidity

As of December 31, 2015, our pro forma[1] liquidity position, excluding RMP, was $1.4 billion, consisting of $1.1 billion of upstream liquidity and $300 million of RMH liquidity.

Pro forma for the preferred equity transaction, our net debt to Further Adjusted EBITDAX[2] was 2.1 times for full year 2015 and 1.7 times for the fourth quarter 2015 annualized.

1. Pro forma for the $375 million preferred equity transaction that closed on February 22, 2016.
2. Please see "Supplemental Non-GAAP Financial Measure" for a description of Further Adjusted EBITDAX.

Operational Results

Marcellus Shale

Marcellus net production averaged 446 MMcfe/d during the fourth quarter, a 9% increase from the prior quarter and a 33% increase relative to fourth quarter 2014.

During the fourth quarter, we turned to sales 6 gross (6 net) horizontal Marcellus wells with an average lateral length of 7,499 feet at an average development cost of $1,192 per lateral foot.

In 2015, we placed online 42 gross (37 net) horizontal Marcellus wells. We exited 2015 with 120 net operated horizontal Marcellus wells producing into sales. As of December 31, 2015, our Marcellus leasehold position in Washington and Greene Counties, Pennsylvania, consisted of approximately 92,000 net acres and 487 undeveloped drilling locations.

In January 2016, we turned 5 gross (5 net) horizontal Marcellus wells to sales with an average lateral length of 6,600 feet.

The following table provides operational data through December 31, 2015, for our operated Marcellus wells.

			Periodic Flow Rates (MMcfe/d)				
Period	**Gross Operated Wells Turned Into Sales**	**Average Lateral Length (Feet)**	**0-90**	**91-180**	**181-360**	**361-720**	**D&C ($/Foot)**
2010-2011	6	3,279	5.7	6.0	4.4	2.7	$ 2,342
2012	9	5,731	9.2	10.0	6.8	4.1	$ 1,583
2013	22	6,320	11.2	10.6	7.6	4.6	$ 1,439
2014[1]	41	7,272	10.6	9.2	6.3	N/A	$ 1,237
2015	42	7,298	9.4	8.3	N/A	N/A	$ 1,181
Total[2]	120	6,792	10.0	9.2	6.6	4.1	$ 1,336

1. Excludes 7 acquired producing wells.
2. With the exception of wells turned into sales, totals represent averages weighted by number of wells.

Utica Shale

Utica net production averaged 174 MMcfe/d for the fourth quarter, a 196% increase relative to fourth quarter 2014.

In 2015, we placed online 14 gross (10 net) horizontal Utica wells, including one Pennsylvania Utica well. We exited the year with 17 gross (12 net) operated Utica wells producing into sales. At year-end 2015, we had a non-operated working interest in 36 gross (7 net) producing horizontal Ohio Utica wells.

As of December 31, 2015, our Ohio Utica leasehold position consisted of approximately 56,000 net acres and 215 undeveloped drilling locations. Our Pennsylvania Utica leasehold position in Washington and Greene Counties, consisted of approximately 49,000 net acres and 105 undeveloped drilling locations.

The following table provides operational data through December 31, 2015, for our operated Ohio Utica wells.

Periodic Flow Rates

Period	Gross Operated Wells Turned Into Sales	Average Lateral Length (Feet)	(MMcf/d) 0-90	91-180	181-360	361-720	D&C($/Foot)
2014	3	8,238	14.3	15.3	16.2	N/A	$ 2,457
2015	13	9,759	15.5	14.3	N/A	N/A	$ 1,653
Total[1]	16	9,474	15.3	14.5	16.2	N/A	$ 1,802

1. With the exception of wells turned into sales, totals represent averages weighted by number of wells.

Midstream Segment

For the fourth quarter, average daily throughput was 1,026 MDth/d, a 74% increase relative to fourth quarter 2014, with 25% attributable to third-party volumes. Gathering, compression and water distribution revenues totaled $38.8 million for the quarter. Operation and maintenance expenses totaled $6.0 million, and operating income was $17.6 million.

For the year ended December 31, 2015, average daily throughput was 894 MDth/d, with 22% attributable to third-party volumes. Gathering, compression and water distribution revenues totaled $141.8 million. Operation and maintenance expenses totaled $17.0 million, and operating income was $75.7 million.

Rice Midstream Partners LP (NYSE: RMP)*("RMP" or the "Partnership")*

Average daily throughput for the fourth quarter was 703 MDth/d, a 36% increase relative to fourth quarter 2014, with 18% attributable to third-party volumes. Water services volumes totaled 202 million gallons, with 58% attributable to third-party volumes. The Partnership reported net income attributable to limited partners of $12.5 million, or $0.18 per limited partner unit.

As of December 31, 2015, RMP had $307 million of undrawn capacity on its revolving credit facility and $8 million of cash on hand, resulting in $315 million of total liquidity.

On January 22, 2016, RMP declared its quarterly distribution of $0.1965 per unit for the fourth quarter 2015, an increase of $0.003 per unit relative to third quarter 2015. The distribution was payable on February 11, 2016 to unitholders of record as of February 2, 2016.

Subsequent to year-end, Rice renegotiated its third party gas gathering agreement for acreage acquired from Chesapeake Appalachia, L.L.C. in August 2014 to increase the acreage dedication from Rice to RMP by 19,000 gross acres to approximately 93,000 gross acres. RMP will gather all production above the first 40 MDth/d, as well as pursue additional third party gathering and water opportunities surrounding this dedication.

Rice Midstream Holdings LLC

Average daily throughput for the fourth quarter of 2015 was 323 MDth/d, a 336% increase relative to fourth quarter 2014, with 40% attributable to third-party volumes. For the year ended December 31, 2015, average daily throughput was 247 MDth/d, with 38% attributable to third-party volumes.

On February 1, 2016, our wholly-owned subsidiary, Strike Force Holdings LLC, and a subsidiary of Gulfport Energy Corporation (NASDAQ: GPOR) completed the formation of its previously announced Utica Shale midstream JV, Strike Force Midstream LLC ("Strike Force"). RMH owns 75% of Strike Force and will act as the operator, and GPOR owns the remaining 25% and dedicated approximately 75,000 leasehold acres. Strike Force will develop natural gas gathering assets to support GPOR's dry gas Utica Shale development in eastern Belmont County and Monroe County, Ohio and will pursue additional third party opportunities within approximately 319,000 acres in the AMI. Strike Force will be supported by long-term, fee-based service agreements with GPOR. Construction of the assets is underway and phase one was completed ahead of schedule, allowing GPOR to commence first flow on a lateral that connected two existing dry gas gathering systems.

2015 Proved Reserves

Proved reserves increased by 30% from year-end 2014 to over 1.7 Tcfe at December 31, 2015. The Marcellus Shale accounted for approximately 75% of our total proved reserves and the Utica Shale accounted for the substantial remainder. Our year-end 2015 proved reserves were 99.8% natural gas with an 8-year estimated reserve life, based on 2015 production. As of December 31, 2015, approximately 15% of our 1,369 total net identified drilling locations were classified as proved.

Estimated Proved Reserves as of December 31, 2015

	SEC Pricing $2.59/MMBtu		**Strip Pricing[1]**			
	Net Reserves (Bcfe)	**PV-10 (in millions)**	**Net Reserves (Bcfe)**	**PV-10 (in millions)**	**Net Locations**	
Proved developed reserves	1,015	$ 802	1,053	$ 935	156	
Proved undeveloped reserves	685	85	698	246	54	
Hedge value		408		265		
Total proved reserves	1,700	$ 1,295	1,751	$ 1,446	210	
Un-booked locations[2]					1,159	
Total Estimated Locations					1,369	
Percent developed locations					11	%

1. Strip pricing: 2016 - $2.45; 2017 - $2.78; 2018 - $2.90; 2019 - $3.01.
2. Represents management's calculation of net locations not included in total proved reserves net locations.

Proved Developed Reserves

Proved developed reserves increased by 57% from year-end 2014 to approximately 1.0 Tcfe, as of December 31, 2015. Approximately 60% of our total proved reserves were classified as proved developed, as compared to 49% at year-end 2014. There were 156 net wells categorized as proved developed at year-end 2015, consisting of 143 net producing wells and 13 net non-producing wells.

Proved Undeveloped Reserves

Proved undeveloped reserves increased by 3% from year-end 2014 to approximately 685 Bcfe, as of December 31, 2015. There were 54 net locations categorized as proved undeveloped at year-end 2015, including 15 net Utica locations. Based on 2015 well cost assumptions, our 685 Bcfe of proved undeveloped reserves will require an estimated $517 million of future development capital over the next five years, which results in an estimated average development cost of $0.75 per Mcfe for our proved undeveloped reserves.

Proved Reserves PV-10

Using NYMEX strip pricing, the pre-tax present value discounted at 10% (pre-tax PV-10) for our year-end 2015 total proved reserves was $1.4 billion, including $265 million of hedge value. Our pre-tax PV-10 value of our proved developed reserves was $935 million.

Using SEC pricing, the pre-tax PV-10 of our year-end 2015 total proved reserves was $1.3 billion, including $408 million of hedge value. Our pre-tax PV-10 value of our proved developed reserves was $802 million. Our estimated proved reserves and PV-10 value were determined using an SEC Henry Hub spot price of $2.59 per MMBtu, which is based on the 12-month unweighted arithmetic average of the first day of the month price for each month in the January through December 2015 period and is not indicative of current forward prices.

Commodity Hedge Position

As depicted in the table below, we have 662 BBtu/d hedged in 2016 at a weighted average floor price of $3.26 MMBtu. Our 2016 hedges cover 87% of our 2016 production (based on the midpoint of guidance). Additionally, for the first quarter of 2016 we have 556 BBtu/d hedged at a weighted average floor price of $3.30 per MMBtu. For 2017 we have 563 BBtu/d hedged at a weighted average floor price of $3.14 MMBtu. Our 2017 hedges are expected to cover more than half of our 2017 production. Please see the "Derivatives Information" table at the end of this press release for more detailed information about our derivatives positions.

Total Fixed Price Derivatives	**2016**	**2017**	**2018**	**2019**
Volume Hedged Excl. Calls (BBtu/d)	662	563	285	150
Weighted Average Swap Price ($/MMBtu)	$3.26	$3.14	$3.16	$3.11

Firm Transportation and Realized Gas Pricing

In 2016, we anticipate that approximately 70% of our production will be transported to premium gas markets outside of Appalachia. The following tables provide basis exposure as a percentage of our production and average differentials to NYMEX for actual results through December 31, 2015 and estimated results for the first quarter of 2016 and full year 2016 and 2017.

	Basis Exposure			
	Actual	Estimated		
	4Q15	1Q16	FY 2016	FY 2017
Gulf Coast	47%	46%	46%	51%
TCO	18%	14%	9%	7%
Midwest/Dawn	26%	18%	14%	9%
DTI / M2 / M3	9%	22%	31%	33%

	Realized Price			
	Actual	Estimated[1]		
	4Q15	1Q16	FY 2016	FY 2017
NYMEX Henry Hub price ($/MMBtu)	$2.23	$2.08	$ 2.16	$ 2.58
Average basis impact ($/MMBtu)	(0.14)	(0.28)	(0.35)	(0.32)
Firm transportation fuel & variables ($/MMBtu)	(0.15)	(0.14)	(0.12)	(0.13)
Btu uplift (MMBtu/Mcf)	0.11	0.10	0.11	0.14
Pre-hedge realized price ($/Mcf)	2.05	1.76	1.80	2.27
Realized hedging gain (loss) ($/Mcf)	1.34	1.03	0.96	0.34
Post-hedge realized price ($/Mcf)	3.39	2.79	2.76	2.61

1. NYMEX price as of 2/18/16.

Conference Call

Rice Energy will host a conference call on February 25, 2016 at 9:30 a.m. Eastern time (8:30 a.m. Central time) to discuss fourth quarter and full year 2015 financial and operating results. To listen to a live audio webcast of the conference call, please visit Rice Energy's website at www.riceenergy.com. A replay of the conference call will be available for two weeks and can also be accessed from our homepage.

Please visit www.riceenergy.com to view a presentation containing fourth quarter and full year 2015 information.

About Rice Energy

Rice Energy Inc. is an independent natural gas and oil company engaged in the acquisition, exploration and development of natural gas and oil properties in the Appalachian Basin. For more information, please visit our website at www.riceenergy.com.

Forward Looking Statements

This release includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than historical facts included or incorporate herein that address activities, events or developments that we expect or anticipate will or may occur in the future, including such things as future capital expenditures (including the amount and nature thereof), projected operational results, production growth, basis exposure, hedging, the timing and number of well completions, forecasted gathering volumes, revenues, adjusted EBITDA, distribution growth, distributable cash flow, private placement by the Partnership, the midstream JV, the timing of completion and nature of midstream projects, business strategy and measures to implement strategy, competitive strengths, goals, expansion and growth of our business and operations, plans, market conditions, references to future success, references to intentions as to future matters and other such matters are forward-looking statements. All forward-looking statements speak only as of the date of this release. Although we believe that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

We caution you that these forward-looking statements are subject to risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas and oil. These risks include, but are not limited to: commodity price volatility; the availability of capital on an economic basis; inflation; lack of availability of drilling and production equipment and services; environmental risks; drilling and other operating risks; legislative and regulatory changes adversely affecting the industry; transportation capacity constraints and interruptions; the uncertainty inherent in estimating natural gas reserves and in projecting future rates of production, cash flow and access to capital; and the timing of development expenditures. Furthermore, the acquisition of the water services business by the Partnership, the concurrent private placement by the Partnership and related transactions may not be completed as described or at all. Information concerning these and other factors can be found in our filings with the Securities and Exchange Commission, including our Forms 10-K, 10-Q and 8-K. Consequently, all of the forward-looking statements made in this news release are qualified by these cautionary statements and there can be no assurances that the actual results or developments anticipated by us will be realized, or even if realized, that they will have the expected consequences to or effects on us, our business or operations. We have no intention, and disclaim any obligation, to update or revise any forward-looking statements, whether as a result of new information, future results or otherwise.

Rice Energy Inc.
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended December 31,		Year Ended December 31,	
(in thousands, except share data)	**2015**	**2014**	**2015**	**2014**
Operating revenues:				
Natural gas, oil and natural gas liquids (NGL) sales	$118,568	$ 112,385	$446,515	$ 359,201
Firm transportation sales, net	98	14,386	3,450	26,237
Gathering, compression and water services	14,424	2,627	49,179	5,504

Other revenue	2,997	—	2,997	—
Total operating revenues	136,087	129,398	502,141	390,942
Operating expenses:				
Lease operating	9,350	8,565	44,356	24,971
Gathering, compression and transportation	29,197	13,154	84,707	35,618
Production taxes and impact fees	2,507	2,024	7,609	4,647
Exploration	1,212	2,436	3,137	4,018
Midstream operation and maintenance	6,024	1,043	16,988	4,607
Incentive unit (income) expense	(9,773)	4,266	36,097	105,961
Stock compensation expense	4,847	2,279	16,528	5,553
Impairment of gas properties	18,250	—	18,250	—
Impairment of goodwill	294,908	—	294,908	—
General and administrative	24,607	19,284	86,510	56,017
Depreciation, depletion and amortization	94,787	64,358	322,784	156,270
Acquisition expense	1,111	92	1,235	2,339
Amortization of intangible assets	408	408	1,632	1,156
Gain from sale of interest in gas properties	—	—	(953)	—
Other expense	2,896	207	6,520	207
Total operating expenses	480,331	118,116	940,308	401,364
Operating (loss) income	(344,244)	11,282	(438,167)	(10,422)
Interest expense	(24,009)	(11,454)	(87,446)	(50,191)
Gain on purchase of Marcellus joint venture	—	—	—	203,579
Other income	167	713	1,108	893
Gain on derivative instruments	89,019	181,120	273,748	186,477
Amortization of deferred financing costs	(1,403)	(766)	(5,124)	(2,495)
Loss on extinguishment of debt	—	(3,720)	—	(7,654)
Write-off of deferred financing costs	—	—	—	(6,896)
Equity in (loss) income of joint ventures	—	—	—	(2,656)
(Loss) income before income taxes	(280,470)	177,175	(255,881)	310,635
Income tax benefit (expense)	6,217	(72,813)	(12,118)	(91,600)
Net (loss) income	(274,253)	104,362	(267,999)	219,035
Less: Net income attributable to non-controlling interests	(6,504)	(581)	(23,337)	(581)
Net (loss) income attributable to Rice Energy Inc.	$(280,757)	$ 103,781	$(291,336)	$ 218,454
Weighted average number of shares of common stock - basic	136,384,591	136,280,766	136,344,076	128,151,171
Weighted average number of shares of common stock - diluted	136,384,591	136,352,435	136,344,076	128,225,155
(Loss) earnings per share—basic	$(2.06)	$ 0.76	$(2.14)	$ 1.70
(Loss) earnings per share—diluted	$(2.06)	$ 0.76	$(2.14)	$ 1.70

Rice Energy Inc.
Segment Results of Operations
(Unaudited)

Exploration and Production Segment

	Three Months Ended		**Year Ended**	
	December 31,		**December 31,**	
(in thousands, except volumes)	**2015**	**2014**	**2015**	**2014**
Operating volumes:				
Natural gas production (MMcf)	57,201	36,076	199,831	97,172

Oil and NGL production (MBbls)	33	91	249	94
Total production (MMcfe)	57,399	36,621	201,328	97,737
Operating revenues:				
Natural gas, oil and NGL sales	$118,568	$112,385	$446,515	$359,201
Firm transportation sales, net	98	14,386	3,450	26,237
Other revenue	2,997	—	2,997	—
Total operating revenues	121,663	126,771	452,962	385,438
Operating expenses:				
Lease operating	9,350	8,565	44,356	24,971
Gathering, compression and transportation	47,994	14,748	150,015	37,414
Production taxes and impact fees	2,507	2,024	7,609	4,647
Exploration	1,212	2,437	3,137	4,018
Incentive unit (income) expense	(10,056)	(4,012)	33,873	86,020
Stock compensation expense	3,140	1,661	11,029	4,532
Impairment of gas properties	18,250	—	18,250	—
Impairment of goodwill	294,908	—	294,908	—
General and administrative	19,680	12,357	67,563	41,697
Depreciation, depletion and amortization	91,529	62,584	308,194	151,900
Gain from sale of interest in gas properties	—	—	(953)	—
Other expense	3,049	—	6,028	—
Acquisition expense	108	58	108	820
Total operating expenses	481,671	100,422	944,117	356,019
Operating (loss) income	$(360,008)	$26,349	$(491,155)	$29,419
Average costs per Mcfe:				
Lease operating	$0.16	$0.23	$0.22	$0.26
Gathering and compression	0.42	—	0.38	—
Transportation	0.42	0.40	0.36	0.38
Production taxes and impact fees	0.04	0.06	0.04	0.05
Exploration	0.02	0.07	0.02	0.04
General and administrative	0.34	0.34	0.34	0.43
Depreciation, depletion and amortization	1.59	1.71	1.53	1.55

Midstream Segment

	Three Months Ended December 31,		**Year Ended December 31,**	
(in thousands, except volumes)	**2015**	**2014**	**2015**	**2014**
Operating volumes:				
Gathering volumes (MDth/d):	1,027	592	894	402
Compression volumes (MDth/d):	295	—	115	—
Water services volumes (MMgal):	202	—	777	—
Operating revenues:				
Gathering revenues	$29,498	$4,589	$101,822	$7,300
Compression revenues	1,158	(368)	2,753	—
Water services revenues	8,141	—	37,248	—

Total operating revenues	38,797	4,221	141,823	7,300
Operating expenses:				
Midstream operation and maintenance	6,024	1,043	16,988	4,607
Incentive unit expense	284	8,278	2,224	19,941
Stock compensation expense	1,707	618	5,499	1,021
General and administrative	4,926	6,927	18,947	14,320
Depreciation, depletion and amortization	6,844	1,773	19,185	4,370
Amortization of intangible assets	408	408	1,632	1,156
Acquisition costs	1,127	35	1,127	1,519
Other expense	(152)	207	492	207
Total operating expenses	21,168	19,289	66,094	47,141
Operating income (loss)	$17,629	$(15,068)	$75,729	$(39,841)

Rice Energy Inc.
Supplemental Non-GAAP Financial Measure
(Unaudited)

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) before non-controlling interest; interest expense; income taxes; depreciation, depletion and amortization; amortization of deferred financing costs; amortization of intangible assets; derivative fair value (gain) loss, excluding net cash receipts on settled derivative instruments; non-cash stock compensation expense; non-cash incentive unit expense; exploration expenses; and other non-recurring items. Adjusted EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles, or GAAP.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDAX to the GAAP financial measure of net income (loss).

	Three Months Ended	**Year Ended**
(in thousands)	**December 31, 2015**	**December 31, 2015**
Adjusted EBITDAX reconciliation to net income (loss):		
Net loss	$ (274,253)	$ (267,999)
Interest expense	24,009	87,446
Depreciation, depletion and amortization	94,787	322,784
Impairment of gas properties	18,250	18,250
Impairment of goodwill	294,908	294,908

Amortization of deferred financing costs	1,403	5,124
Amortization of intangible assets	408	1,632
Gain on derivative instruments[1]	(89,019)	(273,748)
Net cash receipts on settled derivative instruments[1]	76,228	193,908
Acquisition expense	1,111	1,235
Non-cash stock compensation expense	4,847	16,528
Non-cash incentive unit (income) expense	(9,773)	36,097
Income tax (benefit) expense	(6,217)	12,118
Gain from sale of interest in gas properties	—	(953)
Exploration expense	1,212	3,137
Other expense	756	4,380
Non-controlling interest	(6,504)	(23,337)
Adjusted EBITDAX	**$ 132,153**	**$ 431,510**

1. The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative instruments have the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within Adjusted EBITDAX on a cash basis during the period the derivatives settled.

The following table presents a reconciliation of the non-GAAP financial measure of Further Adjusted EBITDAX to Adjusted EBITDAX.

(in thousands)	**Three Months Ended December 31, 2015**	**Year Ended December 31, 2015**
Further Adjusted EBITDAX reconciliation:		
Adjusted EBITDAX	$ 132,153	$ 431,510
Non-controlling interest[1]	6,504	23,337
Water revenue adjustment[2]	5,577	27,336
Further Adjusted EBITDAX	**$ 144,234**	**$ 482,183**
Net Debt[1]		$ 988,649
Net Debt / LTM EBITDAX		2.1
Net Debt / LQA EBITDAX		1.7

1. Add back non-controlling interest to Adjusted EBITDAX to calculate leverage metrics.
2. Add back RMP water distribution revenue from RICE's working interest share of the water fees that was eliminated in the Rice consolidation.

Rice Energy Inc.
Supplemental Non-GAAP Financial Measure
(Unaudited)

Adjusted net income (loss) is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. We define adjusted net income (loss) as net income (loss) before derivative fair value (gain) loss, excluding net cash receipts on settled derivative instruments incentive unit expense and other non-recurring items. Adjusted net income (loss) is not a measure of net income as determined by United States generally accepted accounting principles, or GAAP.

We believe that many investors use adjusted net income in making investment decisions and in evaluating our operational trends and our performance relative to other oil and gas producing companies.

The following table presents a reconciliation of the non-GAAP financial measure of adjusted net income (loss) to the GAAP financial measure of net income (loss).

(in thousands)	Three Months Ended December 31, 2015	Year Ended December 31, 2015
Reconciliation to net income (loss) attributable to Rice Energy Inc:		
Net loss attributable to Rice Energy Inc.	$ (280,757)	$ (291,336)
Impairment of gas properties, net of tax	43,792	12,675
Impairment of goodwill	294,908	294,908
Gain on derivative instruments, net of tax[1]	(213,609)	(190,118)
Net cash receipts on settled derivative instruments, net of tax[1]	182,917	134,669
Incentive unit (income) expense	(9,773)	36,097
Other expense, net of tax	1,815	3,042
Acquisition expense, net of tax	2,666	858
Adjusted net income (loss) attributable to Rice Energy Inc.	**$ 21,959**	**$ 795**

1. The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative instruments have the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses within adjusted net income on a cash basis during the period the derivatives settled.

Rice Energy Inc.
Supplemental Non-GAAP Financial Measure
(Unaudited)

PV-10 is a supplemental non-GAAP financial measure and generally differs from standardized measure, the mist directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 reflects the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our natural gas properties.

The following table presents a reconciliation of the non-GAAP financial measure of PV-10 to the standardized measure of discounted future net cash flows:

(in millions)	Year Ended December 31, 2015	Year Ended December 31, 2014
Reconciliation to PV-10		
Standardized measure of discounted future net cash flows	$ 886	$ 1,308
Discounted future net cash flows for income taxes	—	436
Discounted future net cash flows before income taxes (PV-10)	**$ 886**	**$ 1,744**

Rice Energy Inc.
Derivatives Information
(Unaudited)

The table below provides data associated with our derivatives as of February 23, 2016 for the periods indicated:

All-In Fixed Price Derivatives	**2016**	**2017**	**2018**	**2019**	**2020**
NYMEX Natural Gas Swaps:					
Volume Hedged (BBtu/d)	581	288	5	20	—
Weighted Average Swap Price ($/MMBtu)	$ 3.32	$ 3.27	$ 3.60	$ 3.23	$ —
NYMEX Natural Gas Collars:					
Volume Hedged (BBtu/d)	50	220	280	130	—
Weighted Average Floor Price ($/MMBtu)	$ 2.91	$ 3.13	$ 3.16	$ 3.09	$ —
Weighted Average Collar Price ($/MMBtu)	$ 3.60	$ 3.61	$ 3.62	$ 3.60	$ —
NYMEX Natural Gas Calls:					
Volume Hedged (BBtu/d)	—	50	70	70	65
Weighted Average Price ($/MMBtu)	$ —	$ 3.60	$ 3.50	$ 3.50	$ 3.44
NYMEX Natural Deferred Puts:					
Volume Hedged (BBtu/d)	—	55	—	—	—
Weighted Avg. Net Floor Price ($/MMBtu)	$ —	$ 2.50	$ —	$ —	$ —
NYMEX Volume Excl. Calls (BBtu/d)	**631**	**563**	**285**	**150**	**—**
NYMEX Volume Incl. Calls (BBtu/d)	**631**	**613**	**355**	**220**	**65**
Swap, Collar & Put Floor ($/MMBtu)	**$ 3.29**	**$ 3.14**	**$ 3.16**	**$ 3.11**	**$ —**
Dominion Natural Gas Swaps					
Volume Hedged (BBtu/d)	31	—	—	—	—
Weighted Average Swap Price ($/MMBtu)	$ 2.62	$ —	$ —	$ —	$ —
Total Fixed Price Derivatives					
Volume Hedged Excl. Calls (BBtu/d)	662	563	285	150	—
Volume Hedged Incl. Calls (BBtu/d)	662	613	355	220	65
Weighted Average Swap Price ($/MMBtu)	$ 3.26	$ 3.14	$ 3.16	$ 3.11	$ —
Basis Contract Derivatives					
TCO Basis Swaps					
Volume Hedged (BBtu/d)	44	27	19	10	—
Weighted Average Swap Price ($/MMBtu)	$ (0.32)	$ (0.33)	$ (0.40)	$ (0.38)	$ —
Dominion Basis Swaps					
Volume Hedged (BBtu/d)	76	98	165	150	68
Weighted Average Swap Price ($/MMBtu)	$ (1.01)	$ (0.89)	$ (0.67)	$ (0.63)	$ (0.64)
M2 Basis Swaps					
Volume Hedged (BBtu/d)	61	65	—	—	—
Weighted Average Swap Price ($/MMBtu)	$ (1.03)	$ (1.01)	$ —	$ —	$ —
MichCon Basis Swaps					
Volume Hedged (BBtu/d)	24	4	4	20	20

Weighted Average Swap Price ($/MMBtu)	$ (0.01)	$ (0.04)	$ (0.04)	$ (0.12)	$ (0.12)
<u>ELA Basis Swaps</u>					
Volume Hedged (BBtu/d)	110	80	40	10	—
Weighted Average Swap Price ($/MMBtu)	$ (0.10)	$ (0.09)	$ (0.08)	$ (0.10)	$ —
<u>Chicago Basis Swaps</u>					
Volume Hedged (BBtu/d)	40	10	10	—	—
Weighted Average Swap Price ($/MMBtu)	$ (0.05)	$ (0.16)	$ (0.19)	$ —	$ —
<u>ANR SE Basis Swaps</u>					
Volume Hedged (BBtu/d)	35	—	—	—	—
Weighted Average Swap Price ($/MMBtu)	$ (0.10)	$ —	$ —	$ —	$ —
<u>Physical Triggered Basis</u>					
<u>Appalachian Fixed Basis (Physical)</u>					
Volume Hedged (BBtu/d)	21	—	—	—	20
Weighted Average Swap Price ($/MMBtu)	$ (0.79)	$ —	$ —	$ —	$ (0.65)
<u>MichCon Fixed Basis (Physical)</u>					
Volume Hedged (BBtu/d)	10	10	8	—	—
Weighted Average Swap Price ($/MMBtu)	$ 0.05	$ 0.05	$ 0.05	$ —	$ —
<u>Gulf Coast Fixed Basis (Physical)</u>					
Volume Hedged (BBtu/d)	100	100	100	92	42
Weighted Average Swap Price ($/MMBtu)	$ (0.17)	$ (0.17)	$ (0.17)	$ (0.16)	$ (0.15)
<u>Total Basis Swaps (Financial + Physical)</u>					
Volume Hedged (BBtu/d)	521	394	346	282	150
Weighted Average Swap Price ($/MMBtu)	$ (0.39)	$ (0.47)	$ (0.40)	$ (0.41)	$ (0.44)

The table below provides supplemental balance sheet data as of December 31, 2015.

Supplemental Balance Sheet data (in thousands)	December 31, 2015
Cash and cash equivalents	$ 151,901
Long-term debt	
6.25% Senior Notes Due April 2022	$ 900,000
7.25% Senior Notes Due May 2023	397,222
Senior Secured Revolving Credit Facility	—
Midstream Holdings Revolving Credit Facility	17,000
RMP Revolving Credit Facility	143,000
Total long-term debt	$ 1,457,222
Net debt	$ 1,305,321

The table below outlines our firm transportation capacity by pipeline.

Project	Pipeline	Start Date	Volume (Dth/d)	Term	Market
TEAM South	TETCO	Sept-14	270,000	38 Yrs	Gulf Coast
Westside Expansion	TCO	Nov-14	125,000	10 Yrs	TCO/Gulf Coast
Rockies Express Reversal	REX	Aug-15	175,000	20 Yrs	Midwest/Gulf Coast
Union Town to Gas City	TETCO	Sept-15	86,500	10 Yrs	Midwest/Gulf Coast
OPEN	TETCO	Sept-15	50,000	20 Yrs	Gulf Coast

ET Rover	Rover	Nov-17	100,000	15 Yrs	Canada
Access South	TETCO	Nov-17	320,000	25 Yrs	Gulf Coast

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