Supplemental Q4 and Full Year 2014 Earnings Results

VANGUARD
NATURAL RESOURCES, LLC
NASDAQ: VNR

THE MONTHLY DISTRIBUTION MLP™

Fourth Quarter 2014 Highlights

- Adjusted EBITDA (a non-GAAP financial measure defined below) increased 69% to $125.6 million from $74.3 million in the fourth quarter of 2013 and increased 16% compared to the $108.2 million recorded in the third quarter of 2014.

- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined below) increased 73% to $73.9 million compared to the $42.7 million generated in the fourth quarter of 2013 and increased 39% from the $53.0 million generated in the third quarter of 2014.

- We reported a net loss for the quarter of $66.8 million or $(0.80) per basic unit after deducting distributions to Preferred unitholders compared to a reported net income of $0.9 million or $0.01 per basic unit in the fourth quarter of 2013.

- Adjusted Net Income Available to Common and Class B Unitholders (a non-GAAP financial measure) was $16.1 million in the fourth quarter of 2014, or $0.19 per basic unit, as compared to $10.9 million, or $0.14 per basic unit, in the fourth quarter of 2013. The recent quarter includes net non-cash expenses of $82.5 million that are adjustments to arrive at Adjusted Net Income Available to Common and Class B Unitholders. The 2014 adjustments include a $234.4 million impairment charge on our oil and gas properties offset by a $155.9 million gain from the change in fair value of commodity derivative contracts. The fourth quarter of 2013 results include net non-cash expenses of $10.0 million.

- Reported average production of 402,164 Mcfe per day in the fourth quarter of 2014 was up 82% compared to 221,415 Mcfe per day produced in the fourth quarter of 2013 and a 25% increase compared to the third quarter of 2014. On an Mcfe basis, crude oil, natural gas and NGLs accounted for 15%, 71%, and 14% of our production, respectively.

Full Year 2014 Highlights

- Successfully closed $1.4 billion in acquisitions of natural gas and oil properties during the year ended December 31, 2014.
- Adjusted EBITDA (a non-GAAP financial measure defined below) increased 36% to $421.4 million from the $309.7 million generated in 2013.
- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined below) increased 16% to $214.9 million from the $185.4 million generated in 2013.
- We reported net income available to Common and Class B unitholders for the year ended December 31, 2014 of $46.1 million or $0.56 per basic unit compared to a net income of $56.9 million or $0.78 per basic unit in the year ended December 31, 2013.
- Adjusted Net Income Available to Common and Class B Unitholders (a non-GAAP financial measure) was $90.6 million in 2014, or $1.10 per unit, compared to $69.5 million, or $0.95 per unit, in 2013. The 2014 results include net non-cash losses of $43.7 million that are adjustments to arrive at Adjusted Net Income Available to Common and Class B Unitholders. The 2014 adjustments include a $234.4 million impairment charge on our oil and gas properties offset by a $174.6 million gain from the change in fair value of commodity derivative contracts and a $34.5 million net gain on acquisitions of oil and gas properties. The 2013 results include non-cash losses of $11.8 million.
- Reported average production of 327,109 Mcfe per day in 2014 was up 54% compared to 212,686 Mcfe per day produced in 2013. On an Mcfe basis, crude oil, natural gas and natural gas liquids (“NGLs”) accounted for 16%, 70% and 14% of our production, respectively.

Selected Summary Financials

	Three Months Ended December 31,		Year Ended December 31,	
	2014	2013	2014	2013
	($ in thousands, except per unit data)			
Production (Mcfe/d)	402,164	221,415	327,109	212,686
Oil, natural gas and natural gas liquids sales	$ 156,727	$ 108,319	$ 624,613	$ 443,248
Net gains (losses) on commodity derivative contracts	$ 174,576	$ (350)	$ 163,452	$ 11,256
Operating expenses	$ 51,970	$ 39,507	$ 194,389	$ 145,932
Selling, general and administrative expenses	$ 7,797	$ 6,763	$ 30,839	$ 25,942
Depreciation, depletion, amortization, and accretion	$ 76,139	$ 44,181	$ 226,937	$ 167,535
Impairment of oil and natural gas properties	$ 234,434	$ —	$ 234,434	$ —
Net income (loss) available to Common and Class B Unitholders	$ (66,828)	$ 870	$ 46,148	$ 56,877
Adjusted Net Income Available to Common and Class B Unitholders [(1)]	$ 16,109	$ 10,922	$ 90,593	$ 69,513
Adjusted Net Income Available to Common and Class B Unitholders, per unit [(1)]	$ 0.19	$ 0.14	$ 1.10	$ 0.95
Adjusted EBITDA [(1)]	$ 125,647	$ 74,344	$ 421,445	$ 309,745
Interest expense, including settlements paid on interest rate derivatives	$ 21,245	$ 15,907	$ 73,800	$ 65,036
Estimated maintenance capital expenditures	$ 23,811	$ 14,469	$ 116,528	$ 56,661
Distributions to Preferred unitholders	$ 6,690	$ 1,242	$ 18,197	$ 2,634
Distributable Cash Flow Available to Common and Class B Unitholders [(1)]	$ 73,901	$ 42,726	$ 214,870	$ 185,414
Distributable Cash Flow per Common and Class B unit [(1)]	$ 0.88	$ 0.55	$ 2.61	$ 2.48
Common and Class B units distribution coverage [(1)]	1.40x	0.88x	1.04x	1.00x
Weighted average common and Class B units outstanding at record date attributable to distribution period	83,962	78,228	82,238	74,892

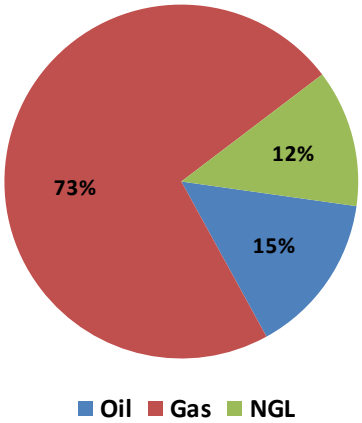
(1) Non-GAAP financial measures. Please see Adjusted EBITDA and Distributable Cash Flow Available to Common and Class B Unitholders table at the end of this presentation for a reconciliation of these measures to their nearest comparable GAAP measure.

2014 Reserve Summary

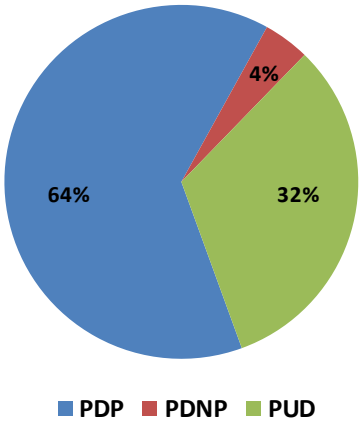
Reserve Summary (SEC Pricing)

Reserve Category	Oil (MMBbls)	Gas (Bcf)	NGLs (MMBbls)	Total (Bcfe)	Net Liquids (%)	PV-10 ($ MM)	PV-10 %
PDP	35.7	916.2	27.0	1,292.0	29%	2,268.3	76%
PDNP	3.4	54.5	1.7	85.6	36%	170.1	6%
PUD	10.9	505.2	13.8	653.7	23%	537.3	18%
Total Proved Reserves	**50.0**	**1,475.9**	**42.5**	**2,031.3**	**27%**	**2,975.7**	**100%**

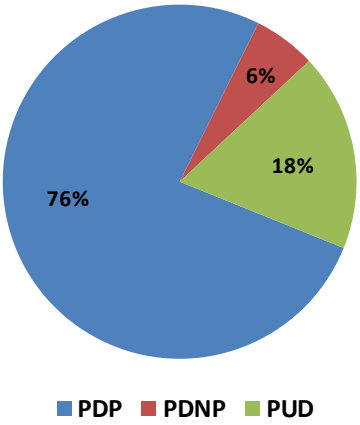
Reserves By Commodity



Reserves By Category



PV-10 By Category



Note: Proved reserves as of 12/31/14 and SEC pricing.

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Commodity Hedge Summary (as of 2/27/15)

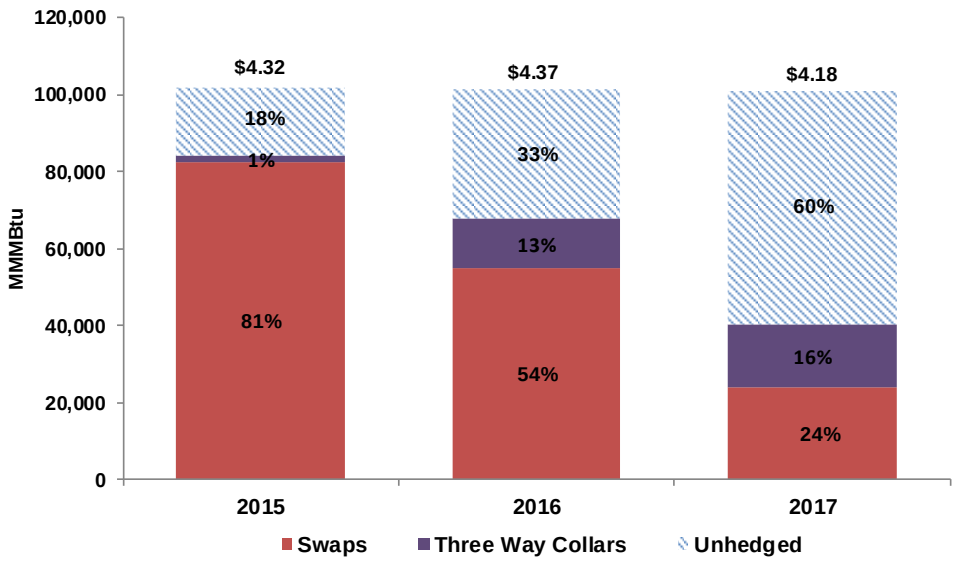
Percent Production Hedged

	Year 2015	Year 2016	Year 2017
Gas Production Hedged:			
% Anticipated Production Hedged	82 %	67 %	40 %
Weighted Average Price ($/MMBtu)	$ 4.32	$ 4.37	$ 4.18
Oil Production Hedged:			
% Anticipated Production Hedged	77 %	45 %	—
Weighted Average Price ($/Bbl)	$ 76.12	$ 83.02	$ —
NGLs Production Hedged:			
% Anticipated Production Hedged	9 %	—	—
Weighted Average Price ($/Bbl)	$ 46.34	$ —	$ —

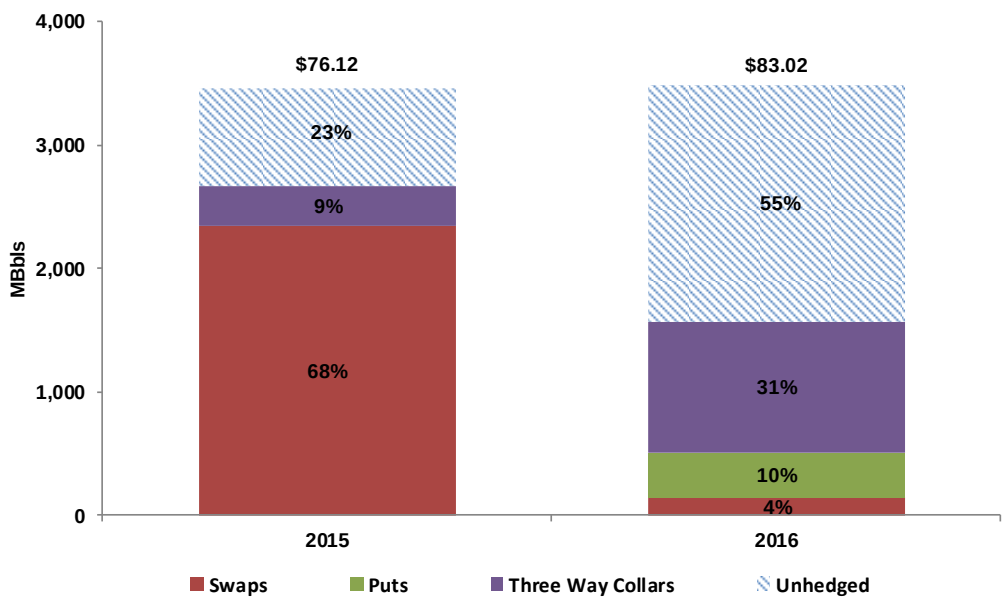
Note: Hedge prices reflect a weighted average of swap prices, long put prices and long put prices on three way collars.

Commodity Hedge Summary (as of 2/27/15)

Natural Gas Hedges



Oil Hedges



Note: Hedge prices reflect a weighted average of swap prices, long puts and long put prices on three way collars.

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Natural Gas Hedge Positions (Full Year)

	Year 2015	Year 2016	Year 2017
Natural Gas Positions:			
Fixed Price Swaps:			
Notional Volume (MMBtu)	82,660,000	55,083,000	24,027,000
Fixed Price ($/MMBtu)	$4.32	$4.47	$4.35
Three Way Collars:			
Notional Volume (MMBtu)	1,472,500	12,810,000	16,425,000
Floor Price ($/MMBtu)	$3.99	$3.95	$3.92
Ceiling Price ($/MMBtu)	$4.668	$4.25	$4.23
Put Sold ($/MMBtu)	$3.38	$3.00	$3.37
Total:			
Notional Volume (MMBtu)	84,132,500	67,893,000	40,452,000
Weighted Average Price ($/MMBtu)	$4.32	$4.37	$4.18
Basis Swaps:			
Notional Volume (MMBtu)	29,200,000	18,300,000	10,950,000
Fixed Price ($/MMBtu)	($0.28)	($0.24)	($0.22)
Puts Sold:			
Notional Volume (MMBtu)	24,990,000	1,830,000	1,825,000
Weighted Average Price ($/MMBtu)	$3.03	$3.00	$3.50
Range Bonus Accumulators:			
Notional Volume (MMBtu)	1,460,000	-	-
Bonus ($/MMBtu)	$0.16	-	-
Range Ceiling ($/MMBtu)	$4.06	-	-
Range Floor ($/MMBtu)	$2.56	-	-

Note: Hedge positions updated as of February 27, 2015.

Oil Hedge Positions (Full Year)

Oil Positions:	Year 2015	Year 2016	Year 2017
Fixed Price Swaps:			
Notional Volume (Bbls)	2,343,000	146,400	-
Fixed Price ($/Bbl)	$74.02	$89.98	-
Puts:			
Notional Volume (Bbls)	-	366,000	-
Floor Price ($/Bbl)	-	$60.00	-
Three Way Collars:			
Notional Volume (Bbls)	330,717	1,061,400	-
Floor Price ($/Bbl)	$91.00	$90.00	-
Ceiling Price ($/Bbl)	$96.44	$96.18	-
Put Sold ($/Bbl)	$75.16	$73.62	-
Total:			
Notional Volume (Bbls)	2,673,717	1,573,800	-
Weighted Average Price ($/Bbl)	$76.12	$83.02	-
Basis Swaps:			
Midland-Cushing			
Notional Volume (Bbls)	511,000	-	-
Fixed Price ($/Bbl)	($1.68)	-	-
WTS-Cushing			
Notional Volume (Bbls)	146,000	-	-
Fixed Price ($/Bbl)	($2.33)	-	-
WTI-WCS			
Notional Volume (Bbls)	612,000	-	-
Fixed Price ($/Bbl)	($14.50)	-	-
Calls Sold:			
Notional Volume (Bbls)	88,283	622,200	365,000
Short Call Price ($/Bbl)	$103.27	$125.00	$95.00
Call Spread:			
Notional Volume (Bbls)	947,600	-	-
Call Price ($/Bbl)	$70.00	-	-
Short Call Price ($/Bbl)	$85.00	-	-
Puts Sold:			
Notional Volume (Bbls)	692,000	146,400	73,000
Weighted Average Price ($/Bbl)	$72.36	$75.00	$75.00
Range Bonus Accumulators:			
Notional Volume (Bbl)	182,500	183,000	-
Bonus ($/Bbl)	$4.00	$4.00	-
Range Ceiling ($/Bbl)	$100.00	$100.00	-
Range Floor ($/Bbl)	$75.00	$75.00	-

Note: Hedge positions updated as of February 27, 2015.

NGL Hedge Positions (Full Year)

	Year 2015	Year 2016	Year 2017
Natural Gas Liquids:			
Fixed Price Swaps			
Mont Belviu Ethane			
Notional Volume (Bbls)	-	-	-
Fixed Price ($/Bbl)	-	-	-
Mont Belviu Propane			
Notional Volume (Bbls)	164,250	-	-
Fixed Price ($/Bbl)	$43.21	-	-
Mont Belviu N. Butane			
Notional Volume (Bbls)	36,500	-	-
Fixed Price ($/Bbl)	$52.08	-	-
Mont Belviu Isobutane			
Notional Volume (Bbls)	45,625	-	-
Fixed Price ($/Bbl)	$53.00	-	-
Mont Belviu N. Gasoline			
Notional Volume (Bbls)	-	-	-
Fixed Price ($/Bbl)	-	-	-
Total			
Notional Volume (Bbls)	246,375	-	-
Fixed Price ($/Bbl)	$46.34	-	-

Note: Hedge positions updated as of February 27, 2015.

Adjusted EBITDA

Adjusted EBITDA

Adjusted EBITDA is a significant performance metric used by management and by external users of our financial statements such as investors, research analysts and others to assess the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and our operating performance and return on capital as compared to those of other companies in our industry.

Adjusted EBITDA is not intended to represent cash flows for the period, nor is it presented as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies. For example, we fund premiums paid for derivative contracts, acquisitions of oil and natural gas properties, including the assumption of derivative contracts related to these acquisitions, and other capital expenditures primarily with proceeds from debt or equity offerings or with borrowings under our Reserve-Based Credit Facility. For the purposes of calculating Adjusted EBITDA, we consider the cost of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investments related to our underlying oil and natural gas properties; therefore, they are not deducted in arriving at our Adjusted EBITDA. Our Consolidated Statements of Cash Flows, prepared in accordance with GAAP, present cash settlements on matured derivatives and the initial cash outflows of premiums paid to enter into derivative contracts as operating activities. When we assume derivative contracts as part of a business combination, we allocate a part of the purchase price and assign them a fair value at the closing date of the acquisition. The fair value of the derivative contracts acquired is recorded as a derivative asset or liability and presented as cash used in investing activities in our Consolidated Statements of Cash Flows. As the volumes associated with these derivative contracts, whether we entered into them or we assumed them, are settled, the fair value is recognized in operating cash flows. Whether these cash settlements on derivatives are received or paid, they are reported as operating cash flows which may increase or decrease the amount we have available to fund distributions.

As noted above, for purposes of calculating Adjusted EBITDA, we consider both premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities. This is similar to the way the initial acquisition or development costs of our oil and natural gas properties are presented in our Consolidated Statements of Cash Flows; the initial cash outflows are presented as cash used in investing activities, while the cash flows generated from these assets are included in operating cash flows. The consideration of premiums paid for derivatives and the fair value of derivative contracts acquired as part of a business combination as investing activities for purposes of determining our Adjusted EBITDA differs from the presentation in our consolidated financial statements prepared in accordance with GAAP which (i) presents premiums paid for derivatives entered into as operating activities and (ii) the fair value of derivative contracts acquired as part of a business combination as investing activities.

Distributable Cash Flow

Distributable Cash Flow Available to Common and Class B Unitholders

Distributable Cash Flow Available to Common and Class B Unitholders is used by management as a tool to measure (prior to the establishment of any cash reserves by our board of directors) the cash distributions we could pay our unitholders. Specifically, this financial measure indicates to investors whether or not we are generating cash flow at a level that can sustain or support an increase in our monthly distribution rates. However, Distributable Cash Flow Available to Common and Class B Unitholders should not be viewed as indicative of the amount that we plan to distribute for a given period. Distributable Cash Flow Available to Common and Class B Unitholders is not intended to be a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Distributable Cash Flow Available to Common and Class B Unitholders is a metric commonly used by investors and the analyst community to assess our financial performance from period to period.

The amount of cash that we have available for distribution depends primarily on our cash flow, including cash from reserves and working capital or other borrowings, and not solely on our GAAP net income, which is affected by non-cash items. As a result, we may be unable to pay distributions even when we record net income, and we may be able to pay distributions during periods when we incur net losses. Our board of directors determines the appropriate level of distributions on a periodic basis in accordance with the provisions of our limited liability company agreement. Management considers the timing and size of capital expenditures and long-term views about expected results in determining the amount of distributions. Capital spending and the resulting production and net cash provided by operating activities do not typically occur evenly throughout the year due to a variety of factors which are difficult to predict, including rig availability, weather, well performance, the timing of completions and the commodity price environment. Consistent with practices common to publicly traded partnerships, our board of directors historically has not varied the distribution it declares period to period based on uneven available distributable cash flow. Our board of directors reviews historical financial results and forecasts for future periods, including development activities, as well as considers the impact of significant acquisitions in making a determination to increase, decrease or maintain the current level of distribution. In instances following acquisitions and development activities, our board of directors reviews any excess in distributable cash flows after distributions to unitholders in those periods, as well as forecasts of expected future net cash flows to determine if increases in distributions could be made. If shortfalls are sustained over time and forecasts demonstrate expectations for continued future shortfalls, our board of directors may determine to reduce, suspend or discontinue paying distributions. Our board of directors may decide to retain the excess in distributable cash flows after distributions to unitholders for our future operations, future capital expenditures, future debt service or other future obligations. Any shortfalls are funded with cash on hand and/or with borrowings under our reserve-based credit facility.

Adjusted Net Income

Adjusted Net Income Available to Common and Class B Unitholders

This information is provided because management believes exclusion of the impact of these items will help investors compare results between periods and identify operating trends that could otherwise be masked by these items and to highlight the significant fluctuations that commodity price volatility has on our results, particularly as it relates to unrealized changes in the fair value of our derivative contracts. Adjusted Net Income Available to Common and Class B Unitholders is not intended to represent cash flows for the period, nor is it presented as a substitute for net income (loss), operating income (loss), cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP.

Adjusted EBITDA and Distributable Cash Flow (a)

	Three Months Ended December 31,		Year Ended December 31,	
	2014	2013	2014	2013
Net income (loss)	$ (60,138)	$ 2,112	$ 64,345	$ 59,511
Plus:				
Interest expense	20,236	14,915	69,765	61,148
Depreciation, depletion, amortization and accretion	76,139	44,181	226,937	167,535
Impairment of oil and natural gas properties	234,434	—	234,434	—
Net (gains) losses on commodity derivative contracts	(174,577)	350	(163,452)	(11,256)
Cash settlements on matured commodity derivative contracts [(b)(c)]	23,534	10,043	10,187	30,905
Net losses on interest rate derivative contracts [(d)]	865	494	1,933	96
Net gains on acquisitions of oil and natural gas properties	—	—	(34,523)	(5,591)
Texas margin taxes	(505)	741	(630)	601
Compensation related items	5,270	1,486	11,710	5,931
Transaction costs incurred on acquisitions	389	22	739	865
Adjusted EBITDA	**$ 125,647**	**$ 74,344**	**$ 421,445**	**$ 309,745**
Less:				
Interest expense, including settlements paid on interest rate derivatives	(21,245)	(15,907)	(73,800)	(65,036)
Estimated maintenance capital expenditures [(e)]	(23,811)	(14,469)	(116,528)	(56,661)
Distributions to Preferred unitholders	(6,690)	(1,242)	(18,197)	(2,634)
Proceeds from sale of leasehold interests	—	—	1,950	—
Distributable Cash Flow Available to Common and Class B unitholders	**$ 73,901**	**$ 42,726**	**$ 214,870**	**$ 185,414**
Distributions to Common and Class B unitholders	52,896	48,697	207,035	184,796
Excess (shortfall) of distributable cash flow after distributions to unitholders	**$ 21,005**	**$ (5,971)**	**$ 7,835**	**$ 618**
Distributable Cash Flow per Common and Class B unit	**$ 0.88**	**$ 0.55**	**$ 2.61**	**$ 2.48**
Common and Class B unit Distribution Coverage	**1.40x**	**0.88x**	**1.04x**	**1.00x**

(a) Our Adjusted EBITDA should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance or liquidity presented in accordance with GAAP. Our Adjusted EBITDA excludes some, but not all, items that affect net income and operating income and these measures may vary among other companies. Therefore, our Adjusted EBITDA may not be comparable to similarly titled measures of other companies.

(b) Excludes premiums paid, whether at inception or deferred, for derivative contracts that settled during the period. We consider the cost of premiums paid for derivatives as an investment related to our underlying oil and natural gas properties.	$ —	$ 55	$ —	$ 220
(c) Excludes the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period. We consider the amounts paid to sellers for derivative contracts assumed with business combinations a part of the purchase price of the underlying oil and natural gas properties.	$ 4,834	$ 7,328	$ 21,306	$ 30,200
(d) Includes settlements paid on interest rate derivatives	$ 1,009	$ 992	$ 4,035	$ 3,888

(e) Estimated maintenance capital expenditures are intended to represent the amount of capital required to offset the decrease in cash flow from the prior year due to the change in natural gas, oil and NGLs prices and the decline in proved developed producing production. These costs, which are incorporated in our annual capital budget as approved by the board of directors, include development drilling, recompletions, workovers and various other procedures to generate new or improve existing cash flow on both operated and non-operated properties. Actual production decline rates and capital efficiency may materially differ from our projections and such estimated maintenance capital expenditures may not maintain our cash flow. 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 cash flow at current levels, which could adversely affect our ability to pay a distribution at the current level or at all.

Adjusted Net Income

	Three Months Ended December 31,		Year Ended December 31,	
	2014	2013	2014	2013
Net Income (Loss) Available to Common and Class B unitholders	$ (66,828)	$ 870	$ 46,148	$ 56,877
Plus (less):				
Change in fair value of commodity derivative contracts	(155,878)	3,010	(174,572)	(10,771)
Change in fair value of interest rate derivative contracts	(144)	(498)	(2,102)	(3,792)
Unrealized fair value of phantom units granted to officers	(699)	190	(837)	1,725
Fair value of derivative contracts acquired that apply to contracts settled during the period	4,834	7,328	21,306	30,200
Net (gains) losses on acquisitions of oil and natural gas properties	—	—	(34,523)	(5,591)
Impairment of oil and natural gas properties	234,434	—	234,434	—
Transaction costs incurred on acquisitions and mergers	390	22	739	865
Adjusted Net Income Available to Common and Class B unitholders	$ 16,109	$ 10,922	$ 90,593	$ 69,513
Net Income (Loss) Available to Common and Class B unitholders, per unit	$ (0.80)	$ 0.01	$ 0.56	$ 0.78
Plus (less):				
Change in fair value of commodity derivative contracts	(1.85)	0.04	(2.13)	(0.15)
Change in fair value of interest rate derivative contracts	—	(0.01)	(0.03)	(0.05)
Unrealized fair value of phantom units granted to officers	(0.01)	—	(0.01)	0.03
Fair value of derivative contracts acquired that apply to contracts settled during the period	0.06	0.10	0.26	0.41
Net (gains) losses on acquisitions of oil and natural gas properties	—	—	(0.42)	(0.08)
Impairment of oil and natural gas properties	2.79	—	2.86	—
Transaction costs incurred on acquisitions and mergers	—	—	0.01	0.01
Adjusted Net Income Available to Common and Class B unitholders, per unit	$ 0.19	$ 0.14	$ 1.10	$ 0.95
Weighted average common and Class B units outstanding	83,974	78,147	82,031	73,064

Coverage Ratio Calculation

Distribution Coverage Ratio

The coverage ratio is used to determine the amount of actual cash distributions the company makes, relative to the amount it could potentially pay out. The amount of distribution which could be paid out is referred to as Distributable Cash Flow. The coverage ratio is then calculated by dividing Distributable Cash Flow by the actual cash distribution.

	Three Months Ended				
	3/31/14	6/30/14	9/30/14	12/31/14	FY 2014
Adjusted EBITDA	$89,863	$97,690	$108,245	$125,647	$421,445
Interest expense, net	(17,249)	(17,564)	(17,742)	(21,245)	(73,800)
Maintenance capital expenditures	(28,814)	(31,337)	(32,566)	(23,811)	(116,528)
Distributions to preferred unitholders	(1,962)	(4,596)	(4,949)	(6,690)	(18,197)
Proceeds from the sale of leasehold interests	-	1,950	-	-	1,950
Distributable cash flow	$41,838	$46,143	$52,988	$73,901	$214,871
Distributable cash flow per unit	$0.5238	$0.5673	$0.6326	$0.88	$2.61
Distribution per unit	$0.6275	$0.6300	$0.6300	$0.6300	$2.52
Units outstanding (millions)	79.9	81.3	83.8	84.0	82.2
Distribution coverage ratio	0.83x	0.90x	1.00x	1.40x	1.04x

Production and Realized Pricing

	Three Months Ended December 31, [a]		Year Ended December 31, [a]	
	2014	2013	2014	2013
Average realized prices, excluding hedging:				
Oil (Price/Bbl)	$ 63.39	$ 82.15	$ 81.40	$ 87.06
Natural Gas (Price/Mcf)	$ 3.19	$ 2.39	$ 3.44	$ 2.48
NGLs (Price/Bbl)	$ 17.37	$ 28.45	$ 25.55	$ 33.72
Average realized prices, including hedging[b]:				
Oil (Price/Bbl)	$ 78.97	$ 78.69	$ 82.88	$ 82.26
Natural Gas (Price/Mcf)	$ 3.52	$ 3.41	$ 3.50	$ 3.39
NGLs (Price/Bbl)	$ 18.22	$ 28.25	$ 25.62	$ 33.76
Average NYMEX prices				
Oil (Price/Bbl)	$ 72.68	$ 97.50	$ 92.21	$ 98.04
Natural Gas (Price/Mcf)	$ 3.99	$ 3.60	$ 4.39	$ 3.66
Total production volumes:				
Oil (MBbls)	907	773	3,301	3,089
Natural Gas (MMcf)	26,386	12,670	83,037	50,236
NGLs (MBbls)	862	511	2,759	1,477
Combined (MMcfe)	36,999	3,395	119,395	77,630
Average daily production volumes:				
Oil (Bbls/day)	9,857	8,398	9,043	8,462
Natural Gas (Mcf/day)	286,805	137,722	227,498	137,632
NGLs (Bbls/day)	9,369	5,551	7,559	4,047
Combined (Mcfe/day)	402,164	221,415	327,109	212,686

(a) During 2014 and 2013, we acquired certain oil and natural gas properties and related assets as well as additional interests in these properties. The operating results of these properties are included with ours from the closing date of acquisition forward.

(b) Excludes the premiums paid, whether at inception or deferred, for derivative contracts that settled during the period and the fair value of derivative contracts acquired as part of prior period business combinations that apply to contracts settled during the period.

Statements of Operations

	Three Months Ended December 31,		Year Ended December 31,	
	2014	2013	2014	2013
Revenues:				
Oil sales	$ 57,488	$ 63,468	$ 268,685	$ 268,922
Natural gas sales	84,264	30,324	285,439	124,513
NGLs sales	14,975	14,527	70,489	49,813
Net gains (losses) on commodity derivative contracts	174,576	(350)	163,452	11,256
Total revenues	331,303	107,969	788,065	454,504
Costs and expenses:				
Production:				
Lease operating expenses	36,789	29,481	132,515	105,502
Production and other taxes	15,181	10,026	61,874	40,430
Depreciation, depletion, amortization and accretion	76,139	44,181	226,937	167,535
Impairment of oil and natural gas properties	234,434	—	234,434	—
Selling, general and administrativeexpenses	7,797	6,763	30,839	25,942
Total costs and expenses	370,340	90,451	686,599	339,409
Income (loss) from operations	(39,037)	17,518	101,466	115,095
Other income (expense):				
Interest expense	(20,236)	(14,915)	(69,765)	(61,148)
Net losses on interest rate derivative contracts	(865)	(494)	(1,933)	(96)
Net gain on acquisitions of oil and natural gas properties	—	—	34,523	5,591
Other income	—	3	54	69
Total other expense	(21,101)	(15,406)	(37,121)	(55,584)
Net income (loss)	(60,138)	2,112	64,345	59,511
Less: Distributions to Preferred unitholders	(6,690)	(1,242)	(18,197)	(2,634)
Net income (loss) available to Common and Class B unitholders	$ (66,828)	$ 870	$ 46,148	$ 56,877
Net income (loss) per Common and Class B unit				
Basic	$ (0.80)	$ 0.01	$ 0.56	$ 0.78
Diluted	$ (0.80)	$ 0.01	$ 0.55	$ 0.77
Weighted average units outstanding:				
Common units – basic	83,554	77,727	81,611	72,644
Common units – diluted	83,844	78,000	82,039	72,992
Class B units – basic & diluted	420	420	420	420

Balance Sheets

	December 31,	
	2014	2013
Assets	(Unaudited)	
Current assets		
Cash and cash equivalents	$ —	$ 11,818
Trade accounts receivable, net	140,017	70,109
Derivative assets	142,114	21,314
Other currents assets	4,102	2,916
Total current assets	286,233	106,157
Oil and natural gas properties, at cost	4,140,527	2,523,671
Accumulated depletion, amortization and impairment	(1,164,721)	(713,154)
Oil and natural gas properties evaluated, net– full cost method	2,975,806	1,810,517
Other assets		
Goodwill	420,955	420,955
Derivative assets	83,583	60,474
Other assets	27,015	91,538
Total assets	$ 3,793,592	$ 2,489,641
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 15,118	$ 9,824
Affiliates	823	249
Accrued liabilities:		
Lease operating	19,822	12,882
Developmental capital	24,706	10,543
Interest	11,517	11,989
Production and other taxes	29,981	16,251
Derivative liabilities	3,583	10,992
Oil and natural gas revenue payable	40,117	23,245
Distributions payable	18,640	16,499
Other	14,297	12,929
Total current liabilities	178,604	125,403
Long-term debt	1,932,816	1,007,879
Derivative liabilities	1,380	4,085
Asset retirement obligations	146,676	82,208
Other long-term liabilities	—	1,731
Total liabilities	2,259,476	1,221,306
Commitments and contingencies		
Members' equity		
Cumulative Preferred units, 13,881,873 and 2,535,927 units issued and outstanding at December 31, 2014 and 2013	335,444	61,021
Members' capital, 83,451,746 and 78,337,259 common units issued and outstanding at December 31, 2014 and 2013, respectively	1,191,057	1,199,699
Class B units, 420,000 issued and outstanding at December 31, 2014 and 2013, respectively	7,615	7,615
Total members' equity	1,534,116	1,268,335
Total liabilities and members' equity	$ 3,793,592	$ 2,489,641