Supplemental Q4 and Full Year 2013 Earnings Results

VANGUARD
NATURAL RESOURCES, LLC
NASDAQ: VNR

THE MONTHLY DISTRIBUTION MLP™

Full Year 2013 Highlights

- The annualized monthly distribution of $2.49 per unit as of December 2013 represents a 2.5% increase over the annualized quarterly distribution of $2.43 per unit as of December 2012.

- Adjusted EBITDA (a non-GAAP financial measure defined below) increased 34% to $309.7 million from the $230.5 million generated in 2012.

- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined below) increased 31% to $185.4 million from the $141.2 million generated in 2012.

- We reported net income available to Common and Class B unitholders for the year ended December 31, 2013 of $56.9 million or $0.78 per basic unit compared to a net loss of $168.8 million or $(3.11) per basic unit in the year ended December 31, 2012.

- Adjusted Net Income Available to Common and Class B Unitholders was $69.5 million in 2013, or $0.95 per unit, compared to $64.1 million, or $1.18 per unit, in 2012. The 2013 results include net non-cash losses of $11.8 million that are adjustments to arrive at Adjusted Net Income Available to Common and Class B Unitholders (a non-GAAP financial measure defined below). The 2012 results include non-cash expenses of $232.9 million, the largest item of which is a $247.7 million impairment charge on our oil and gas properties.

- Reported average production of 35,448 BOE per day in 2013 was up 94% over 18,298 BOE per day produced in 2012. On a BOE basis, crude oil, natural gas and natural gas liquids ("NGLs") accounted for 24%, 65% and 11% of our production, respectively.

Fourth Quarter 2013 Highlights

- Adjusted EBITDA (a non-GAAP financial measure defined below) increased 12% to $74.3 million from $66.5 million in the fourth quarter of 2012 and decreased 10% compared to the $82.7 million recorded in the third quarter of 2013.
- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined below) remained relatively flat at $42.7 million compared to the $41.2 million generated in the fourth quarter of 2012 and decreased 19% from the $52.9 million generated in the third quarter of 2013.
- We reported a net income for the quarter of $0.9 million or $0.01 per basic unit after deducting distributions to Preferred unitholders compared to a reported net loss of $201.5 million or $(3.41) per basic unit in the fourth quarter of 2012.
- Adjusted Net Income Available to Common and Class B Unitholders (a non-GAAP financial measure defined below) was $10.9 million in the fourth quarter of 2013, or $0.14 per basic unit, as compared to $16.0 million, or $0.27 per basic unit, in the fourth quarter of 2012. The recent quarter includes net non-cash expenses of $10.0 million that are adjustments to arrive at Adjusted Net Income Available to Common and Class B Unitholders (a non-GAAP financial measure defined below). The fourth quarter of 2012 results include net non-cash expenses of $217.5 million, the largest item of which is a $229.7 million impairment charge on our oil and gas properties.
- Reported average production of 36,903 BOE per day in the fourth quarter of 2013 was up 62% over 22,803 BOE per day produced in the fourth quarter of 2012 and a 5% increase over third quarter of 2013. On a BOE basis, crude oil, natural gas and NGLs accounted for 23%, 62%, and 15% of our production, respectively.

Selected Summary Financials

	Three Months Ended December 31,				Year Ended December 31,			
	2013		2012		2013		2012	
	($ in thousands, except per unit data)							
Production (BOE/d)		36,903		22,803		35,448		18,298
Oil, natural gas and natural gas liquids sales	$	108,319	$	82,327	$	443,248	$	310,356
Net gains (losses) on commodity derivative contracts	$	(350)	$	28,359	$	11,256	$	36,846
Operating expenses	$	39,507	$	27,817	$	145,932	$	103,735
Selling, general and administrative expenses	$	6,763	$	7,168	$	25,942	$	22,466
Depreciation, depletion, amortization, and accretion	$	44,181	$	30,645	$	167,535	$	104,542
Impairment of oil and natural gas properties	$	—	$	229,693	$	—	$	247,722
Net income (loss) available to Common and Class B Unitholders	$	870	$	(201,511)	$	56,877	$	(168,815)
Adjusted Net Income Available to Common and Class B Unitholders [1]	$	10,922	$	15,978	$	69,513	$	64,131
Adjusted Net Income Available to Common and Class B Unitholders, per unit [1]	$	0.14	$	0.27	$	0.95	$	1.18
Adjusted EBITDA [1]	$	74,344	$	66,547	$	309,745	$	230,512
Interest expense, including settlements paid on interest rate derivatives	$	15,907	$	15,248	$	65,036	$	44,406
Drilling, capital workover and recompletion expenditures	$	14,469	$	10,120	$	56,661	$	50,405
Distributions to Preferred unitholders	$	1,242	$	—	$	2,634	$	—
Distributable Cash Flow Available to Common and Class B Unitholders [1]	$	42,726	$	41,179	$	185,414	$	141,223
Distributable Cash Flow per Common and Class B unit [1]	$	0.55	$	0.70	$	2.48	$	2.60
Common and Class B units distribution coverage [1]		0.88x		1.15x		1.00x		1.08x
Weighted average Common and Class B units outstanding		78,147		59,088		73,064		54,197

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

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2014E Outlook

	FY 2014E	FY 2013
Net Production:		
Oil (Bbls/d)	8,800 - 9,400	8,462
Natural gas (Mcf/d)	215,000 - 229,000	137,632
Natural gas liquids (Bbls/d)	7,200 - 7,650	4,047
Total (BOE/d)	51,883 - 55,217	35,448
Costs per BOE:		
Lease operating expenses	$6.00 - $7.00	$8.15
Production taxes (% of revenue)	10.5% - 11%	9.1%
G&A expenses (excluding non-cash compensation)	$1.00 - $1.20	$1.55
Depreciation, depletion and amortization	$10.00 - $11.00	$12.95
Cash Flow Calculation (in thousands):		
Adjusted EBITDA [1]	$415,000	309,745
Interest expense, including settlements paid on interest rate derivatives	(72,000)	(65,036)
Maintenance capital expenditures[2]:	(114,000)	(56,661)
Distributions to preferred unitholders	(5,000)	(2,634)
Distributable cash flow	$224,000	$185,414
Excess of net cash after distributions to unitholders	$25,500	$618
Mid-point distributable cash flow per unit	$2.81	$2.48
Mid-point distribution coverage ratio [3]	1.12x	1.00x
Mid-point adjusted net income per unit[1]	$1.15	$0.95
Units outstanding (millions) [4]	79.7	74.9

Assumed NYMEX Pricing (February 21, 2014)[5]:	**Q1 2014**	**Q2 - Q4 2014**	**FY 2013**
Oil ($/Bbl)	$98.81	$97.26	$98.04
Natural gas ($/MMBtu)	$5.37	$4.78	$3.66
Average NYMEX Differentials:			
Oil ($/Bbl)	$(11.25)	$(9.75)	$(10.98)
Natural gas ($/MMBtu)	$(1.05)	$(1.20)	$(1.18)
NGL realization as a percentage of crude oil NYMEX price[6]	35%	30%	34%

Capital Expenditures Details (in thousands):	**Q1 2014**	**Q2 2014**	**Q3 2014**	**Q4 2014**
Maintenance Capital:				
Operated	$(9,000)	$(7,750)	$(11,500)	$(7,000)
Non-Operated	$(19,750)	$(21,500)	$(19,000)	$(18,500)
Growth Capital:				
Operated	$—	$—	$—	$—
Non-Operated	$(4,000)	$(6,000)	$(6,000)	$(6,500)
Total Capital:				
Operated	$(9,000)	$(7,750)	$(11,500)	$(7,000)
Non-Operated	$(23,750)	$(27,500)	$(25,000)	$(25,000)

2014E Outlook (continued)

(1) Adjusted EBITDA and Adjusted Net Income Available to Common and Class B Unitholders (non-GAAP financial measures defined below) exclude the fair value of derivative contracts acquired that apply to contracts settled during the period (approximately $21.0 MM for the FY 2014E). Adjusted EBITDA and Adjusted Net Income Available to Common and Class B Unitholders assume the mid-point of all the above ranges.

(2) Additional detail regarding the maintenance capital breakout by quarter is listed below. Estimated 2014E maintenance capital expenditures are based on the amount of capital needed 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 (PDP) production.

(3) Assumes monthly distribution rate of $0.2075 per unit for January 2014 and $0.21 per unit beginning in February 2014 ($2.5175 per unit on an annualized basis for 2014).

(4) Includes common and Class B units.

(5) NYMEX pricing includes actual settlements for January 2014 and February 2014 for natural gas and January 2014 for oil.

(6) Assumes a weighted average product breakout of 38% ethane, 27% propane, 9% isobutane, 13% n-butane and 13% pentane.

2014E Distribution Coverage Sensitivities

- Vanguard’s distribution coverage is stable even in a changing commodity price environment

2014 DISTRIBUTION COVERAGE SENSITIVITY

	$3.00	$4.00	$5.00	$6.00	$7.00
$70.00	1.05x	1.07x	1.09x	1.10x	1.12x
$80.00	1.08x	1.10x	1.12x	1.13x	1.15x
$90.00	1.08x	1.09x	1.11x	1.13x	1.15x
$100.00	1.08x	1.09x	1.11x	1.13x	1.14x
$110.00	1.06x	1.07x	1.09x	1.11x	1.12x

Note: Based on 2014E Outlook and assumptions announced on February 26, 2014.

YE 2013 Reserve Summary

- 2013 SEC Reserve Mix
  - Does not include Pinedale Acquisition
  - 43% liquids / 57% natural gas
  - 78% proved developed

Reserves By Area

Area	Reserves (MMBoe)	Percentage (%)
Arkoma	62.2	36%
Permian	42.4	25%
Big Horn	21.2	12%
Piceance	19.0	11%
Gulf Coast	9.4	6%
Wind River	8.7	5%
Williston	5.8	3%
Powder River	3.5	2%
Total	**172.2**	**100%**

By Commodity

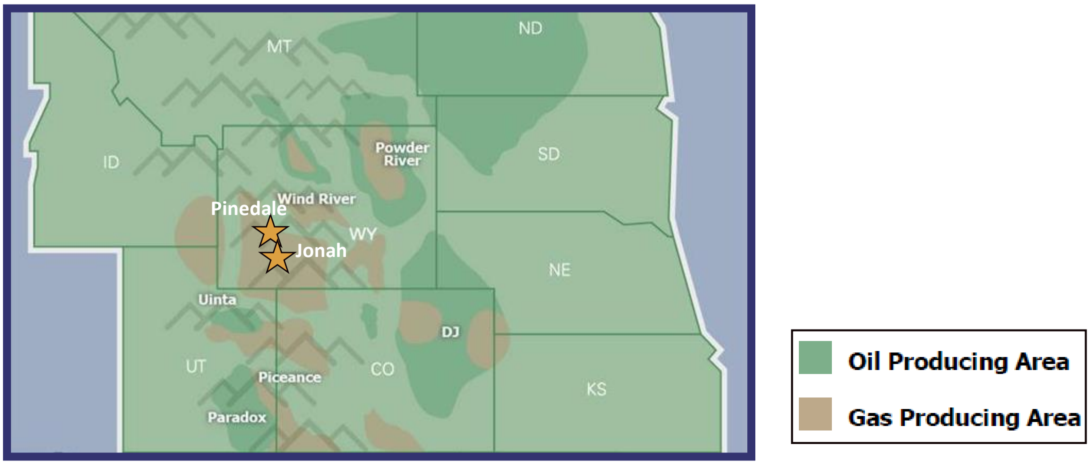
Commodity	Reserves (MMBoe)	Percentage (%)
Oil	45.3	26%
Natural Gas	97.7	57%
NGLs	29.2	17%
Total	**172.2**	**100%**

By Reserve Class

Reserve Class	Reserves (MMBoe)	Percentage (%)
PDP	123.1	71%
PDNP	11.8	7%
PUD	37.3	22%
Total	**172.2**	**100%**

Pinedale Acquisition

Pinedale and Jonah Fields in Green River Basin Wyoming



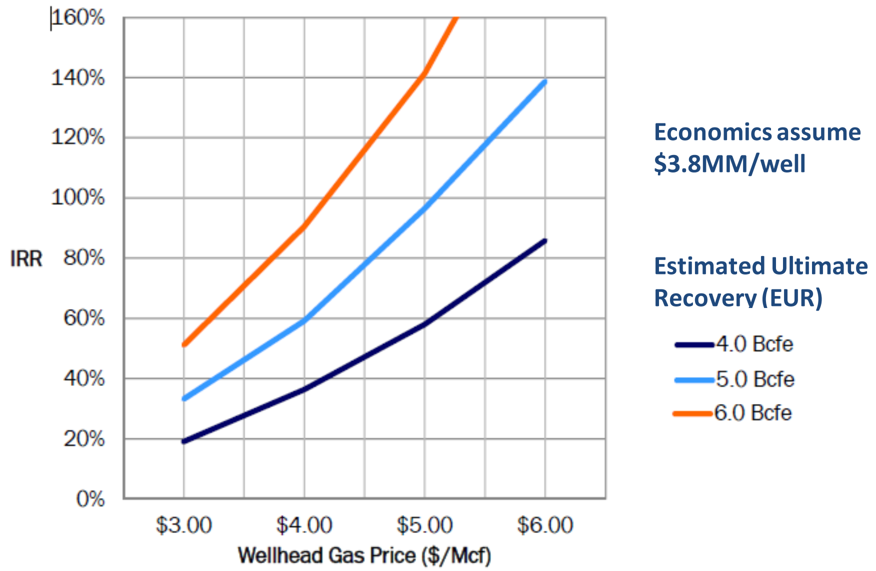
Summary Acquisition Overview

- Closed on January 31, 2014
- Natural gas and oil assets located in the Pinedale and Jonah Fields of Southwestern Wyoming in the Green River Basin
- Estimated reserve life of over 20 years on internally estimated proved reserves of ~847 Bcfe (~765 Bcfe at SEC pricing)
- 87,000 gross acres (14,000 net acres) currently producing ~113.4 Mmcfe/d
- Reserve mix ~79% natural gas, ~17% natural gas liquids and ~4% oil
- ~2,000 producing wells and ~970 proved undeveloped drilling (PUD) locations will be added to Vanguard's inventory
- 100% non-operated properties with an average working interest of 10%
- Vanguard is partnering with two major operators in the area (Ultra Petroleum Corp. and QEP Resources, Inc.)
- Expect an 8 rig drilling program; each rig anticipated to drill 2 wells per month in 2014 (~192 wells in 2014)
- Immediately accretive to cash flow

Pinedale Well Economics

- Pinedale well economics are very strong and based on recent results and natural gas prices can achieve rates of return in excess of 50%+

Gas Price and EUR Sensitivity



Well Cost and EUR Sensitivity

EUR (Bcfe)

Well Cost ($/MM)	4.0	5.0	6.0	7.0
$4.7	22%	37%	56%	77%
$4.4	26%	44%	65%	92%
$3.8	36%	59%	91%	126%

Economics at $4.00/Mcf wellhead price

Source: Ultra Petroleum management presentation (Capital One Southcoast Presentation; December 11, 2013).

2014E Maintenance Capex Calculation

- The estimated 2014E maintenance capital expenditures is based on the amount of capital needed 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 (PDP) production.

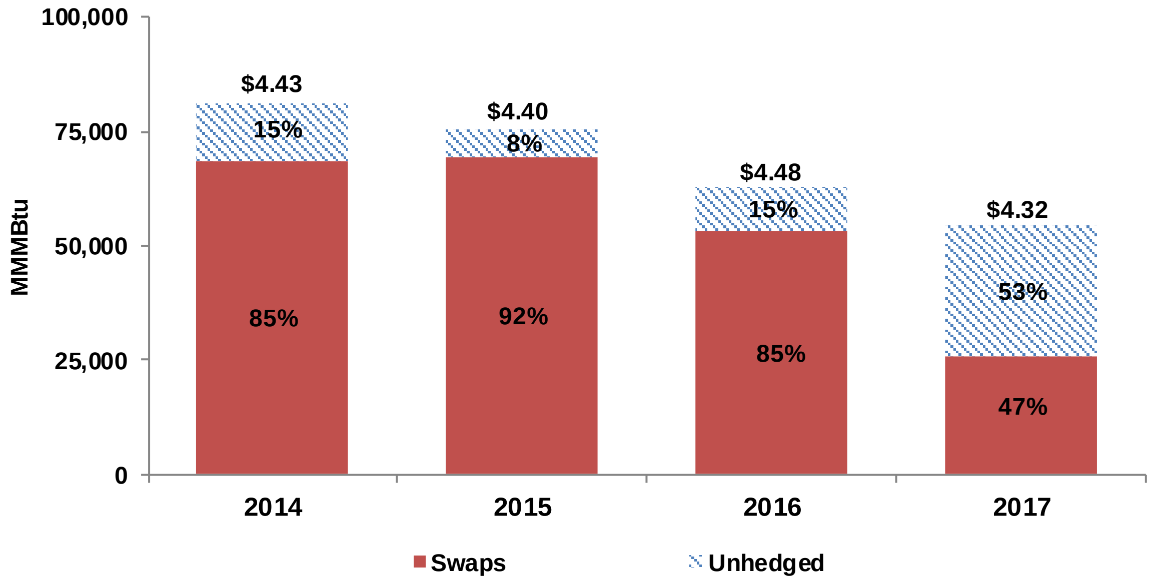
($ millions)

EBITDA to Maintain	
2013 VNR Pro Forma (Excluding Pinedale Acquisition)	
Range Permian Acquisition Q1 2013 EBITDA	7
VNR 2013 Adjusted EBITDA	310
Total 2013 Pro Forma Adjusted EBITDA (Excluding Pinedale Acquisition)	317
Pinedale Acquisition Maintenance EBITDA (11 months)	92
Total Pro Forma EBITDA to Maintain in 2014	**408**

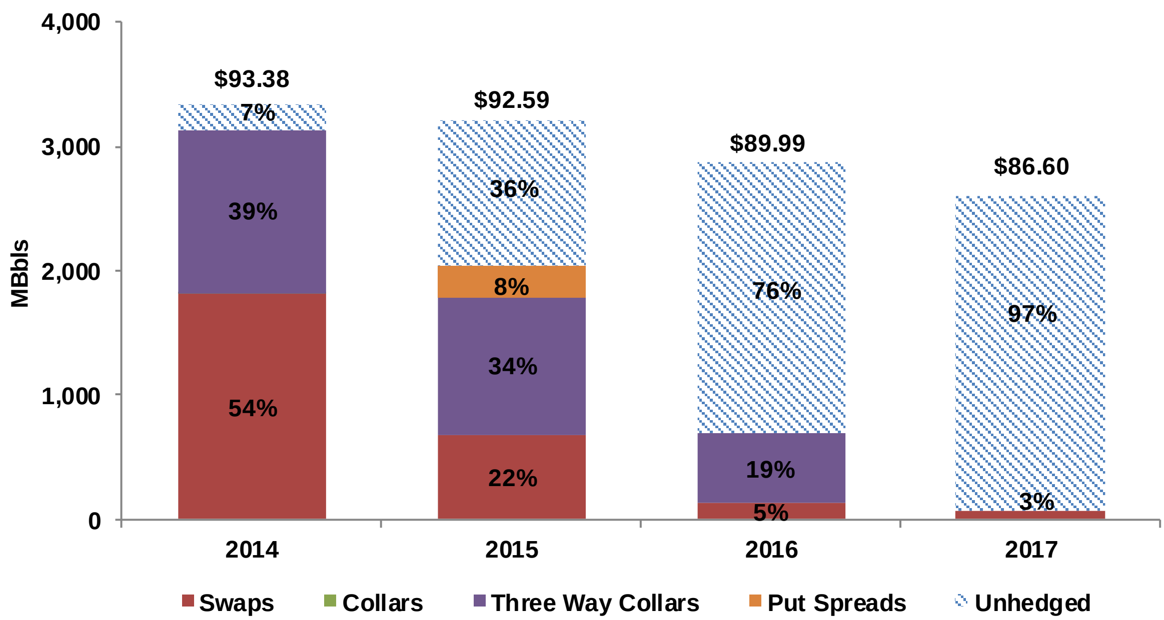
2014E Adjusted EBITDA / Capex Breakdown	**Adjusted EBITDA**	**Capital Expenditures**
2014E Proved Developed Producing (PDP)	352	-
2014E Maintenance Capital Program	56	114
Total PDP and Maintenance	**408**	**114**
2014E Growth Capital Program	7	23
Grand Total	**415**	**137**

Commodity Hedge Summary (as of 2/26/14)

Gas Hedges



Oil Hedges



Note: Hedge prices reflect a weighted average of swap prices, floor prices on collars and long put prices on three way collars. Excludes NGL production. Weighted average floor price includes impact from the range bonus accumulators.

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Natural Gas Hedge Positions (Full Year)

	Year 2014	Year 2015	Year 2016	Year 2017
Natural Gas Positions:				
Fixed Price Swaps:				
Notional Volume (MMBtu)	68,760,225	69,532,500	53,253,000	25,852,000
Fixed Price ($/MMBtu)	$4.43	$4.39	$4.48	$4.32
Total:				
Notional Volume (MMBtu)	68,760,225	69,532,500	53,253,000	25,852,000
Fixed Price ($/MMBtu)	$4.43	$4.40	$4.48	$4.32
Basis Swaps:				
Northwest Rockies Pipeline - NYMEX				
Notional Volume (MMBtu)	26,875,000	27,375,000	-	-
Fixed Price ($/MMBtu)	($0.20)	($0.29)	-	-
CIG Rockies - NYMEX				
Notional Volume (MMBtu)	452,500	-	-	-
Fixed Price ($/MMBtu)	($0.32)	-	-	-
Puts Sold:				
Notional Volume (MMBtu)	3,340,000	7,300,000	-	-
Fixed Price ($/MMBtu)	$3.50	$3.50	-	-
Range Bonus Accumulators:				
Notional Volume (MMBtu)	1,460,000	1,460,000	-	-
Bonus ($/MMBtu)	$0.20	$0.20	-	-
Range Ceiling ($/MMBtu)	$4.75	$4.75	-	-
Range Floor ($/MMBtu)	$3.25	$3.25	-	-

Note: Weighted average floor price includes impact from the range bonus accumulators. Hedge positions as of February 26, 2014.

Oil Hedge Positions (Full Year)

Oil Positions:	Year 2014	Year 2015	Year 2016	Year 2017
Fixed Price Swaps:				
Notional Volume (Bbls)	1,815,875	692,000	146,400	73,000
Fixed Price ($/Bbl)	$90.79	$91.18	$89.98	$86.60
Collars:				
Notional Volume (Bbls)	12,000	-	-	-
Floor Price ($/Bbl)	$100.00	-	-	-
Ceiling Price ($/Bbl)	$116.20	-	-	-
Three Way Collars:				
Notional Volume (Bbls)	1,313,850	1,105,055	549,000	-
Floor Price ($/Bbl)	$93.47	$91.76	$90.00	-
Ceiling Price ($/Bbl)	$101.25	$100.38	$95.00	-
Put Sold ($/Bbl)	$72.57	$72.52	$70.00	-
Put Spreads:				
Notional Volume (Bbl)	-	255,500	-	-
Floor Price ($/Bbl)	-	$100.00	-	-
Put Sold ($/Bbl)	-	$75.00	-	-
Total:				
Notional Volume (Bbls)	3,141,725	2,052,555	695,400	73,000
Fixed Price ($/Bbl)	$93.38	$92.59	$89.99	$86.60
Basis Swaps:				
Midland-Cushing				
Notional Volume (Bbls)	584,000	365,000	-	-
Fixed Price ($/Bbl)	($0.84)	($0.90)	-	-
WTS-Cushing				
Notional Volume (Bbls)	328,500	-	-	-
Fixed Price ($/Bbl)	($1.05)	-	-	-
LLS-Brent				
Notional Volume (Bbls)	182,500	-	-	-
Fixed Price ($/Bbl)	($3.95)	-	-	-
Swaptions and Calls:				
Notional Volume (Bbls)	492,750	508,445	622,200	-
Fixed Price ($/Bbl)	$104.80	$105.98	$125.00	-
Puts Sold:				
Notional Volume (Bbls)	73,000	692,000	146,400	73,000
Put Sold ($/Bbl)	$75.00	$72.36	$75.00	$75.00
Range Bonus Accumulators:				
Notional Volume (Bbl)	912,500	-	-	-
Bonus ($/Bbl)	$4.94	-	-	-
Range Ceiling ($/Bbl)	$103.20	-	-	-
Range Floor ($/Bbl)	$70.50	-	-	-

Note: Weighted average floor price includes impact from the range bonus accumulators. Hedge positions as of February 26, 2014.

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NGL Hedge Positions (Full Year)

	Year 2014	Year 2015	Year 2016	Year 2017
Natural Gas Liquids:				
Fixed Price Swaps				
Mont Belviu Ethane				
Notional Volume (Bbls)	70,774	-	-	-
Fixed Price ($/Bbl)	$11.0250	-	-	-
Mont Belviu Propane				
Notional Volume (Bbls)	144,157	91,250	-	-
Fixed Price ($/Bbl)	$40.4971	$42.00	-	-
Mont Belviu N. Butane				
Notional Volume (Bbls)	15,075	-	-	-
Fixed Price ($/Bbl)	$65.6208	-	-	-
Mont Belviu Isobutane				
Notional Volume (Bbls)	16,078	-	-	-
Fixed Price ($/Bbl)	$70.2366	-	-	-
Mont Belviu N. Gasoline				
Notional Volume (Bbls)	27,667	-	-	-
Fixed Price ($/Bbl)	$88.5738	-	-	-
Total				
Notional Volume (Bbls)	273,750	91,250	-	-
Fixed Price ($/Bbl)	$40.8667	$42.00	-	-

Note: Hedge positions as of February 26, 2014.

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 (loss), operating income (loss), 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 (loss) and operating income (loss) 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.

However, 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 (loss), operating income (loss), 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 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, 2013	Three Months Ended December 31, 2012	Year Ended December 31, 2013	Year Ended December 31, 2012
Net income (loss)	$ 2,112	$ (201,511)	$ 59,511	$ (168,815)
Plus:				
Interest expense	14,915	14,343	61,148	41,891
Depreciation, depletion, amortization and accretion	44,181	30,645	167,535	104,542
Impairment of oil and natural gas properties	—	229,693	—	247,722
Net (gains) losses on commodity derivative contracts	350	(28,359)	(11,256)	(36,846)
Cash settlements on matured commodity derivative contracts [(b)(c)]	10,043	15,246	30,905	39,102
Net (gains) losses on interest rate derivative contracts[(d)]	494	(125)	96	6,992
Net (gain) loss on acquisitions of oil and natural gas properties	—	2,685	(5,591)	(11,111)
Texas margin taxes	741	392	601	239
Compensation related items	1,486	3,538	5,931	6,796
Material transaction costs incurred on acquisitions	22	—	865	—
Adjusted EBITDA	**$ 74,344**	**$ 66,547**	**$ 309,745**	**$ 230,512**
Less:				
Interest expense, including settlements paid on interest rate derivatives	(15,907)	(15,248)	(65,036)	(44,406)
Drilling, capital workover and recompletion expenditures	(14,469)	(10,120)	(56,661)	(50,405)
Distributions to Preferred unitholders	(1,242)	—	(2,634)	—
Proceeds from sale of leasehold interests	—	—	—	5,522
Distributable Cash Flow Available to Common and Class B unitholders	**$ 42,726**	**$ 41,179**	**$ 185,414**	**$ 141,223**
Distributions to Common and Class B unitholders	48,697	35,901	184,796	130,584
Excess (shortfall) of distributable cash flow after distributions to unitholders	**$ (5,971)**	**$ 5,278**	**$ 618**	**$ 10,639**
Distributable Cash Flow per Common and Class B unit	**$ 0.55**	**$ 0.70**	**$ 2.48**	**$ 2.60**
Common and Class B unit Distribution Coverage	**0.88x**	**1.15x**	**1.00x**	**1.08x**

(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	$ 1,125	$ 220	$ 11,641
(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.	$ 7,328	$ 12,409	$ 30,200	$ 26,505
(d) Includes settlements paid on interest rate derivatives	$ 992	$ 905	$ 3,888	$ 2,515

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Adjusted Net Income

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Year Ended December 31, 2013	Year Ended December 31, 2012
Net Income (Loss) Available to Common and Class B unitholders	$ 870	$ (201,511)	$ 56,877	$ (168,815)
Plus (less):				
Change in fair value of commodity derivative contracts	3,010	(26,647)	(10,771)	(35,890)
Change in fair value of interest rate derivative contracts	(498)	(1,030)	(3,792)	4,477
Unrealized fair value of phantom units granted to officers	190	379	1,725	1,243
Fair value of derivative contracts acquired that apply to contracts settled during the period	7,328	12,409	30,200	26,505
Net (gain) loss on acquisition of oil and natural gas properties	—	2,685	(5,591)	(11,111)
Impairment of oil and natural gas properties	—	229,693	—	247,722
Material transaction costs incurred on acquisitions and mergers	22	—	865	—
Adjusted Net Income Available to Common and Class B unitholders	$ 10,922	$ 15,978	$ 69,513	$ 64,131

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Year Ended December 31, 2013	Year Ended December 31, 2012
Net Income (Loss) Available to Common and Class B unitholders, per unit	$ 0.01	$ (3.41)	$ 0.78	$ (3.11)
Plus (less):				
Change in fair value of commodity derivative contracts	0.04	(0.45)	(0.15)	(0.66)
Change in fair value of interest rate derivative contracts	(0.01)	(0.02)	(0.05)	0.08
Unrealized fair value of phantom units granted to officers	—	—	0.03	0.02
Fair value of derivative contracts acquired that apply to contracts settled during the period	0.10	0.21	0.41	0.49
Net (gain) loss on acquisition of oil and natural gas properties	—	0.05	(0.08)	(0.21)
Impairment of oil and natural gas properties	—	3.89	—	4.57
Material transaction costs incurred on acquisitions and mergers	—	—	0.01	—
Adjusted Net Income Available to Common and Class B unitholders, per unit	$ 0.14	$ 0.27	$ 0.95	$ 1.18

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				
	3/31/13	6/30/13	9/30/13	12/31/13	FY 2013
Adjusted EBITDA	$72,433	$80,282	$82,687	$74,344	$309,745
Interest expense, net	(16,385)	(16,925)	(15,819)	(15,907)	(65,036)
Capital expenditures	(14,648)	(14,770)	(12,774)	(14,469)	(56,661)
Distributions to preferred unitholders	-	(152)	(1,240)	(1,242)	(2,634)
Distributable cash flow	$41,400	$48,435	$52,854	$42,726	$185,414
Distributable cash flow per unit	$0.61	$0.65	$0.68	$0.55	$2.48
Distribution per unit	$0.6075	$0.6150	$0.6225	$0.6225	$2.47
Units outstanding (millions)	68.4	74.8	77.9	78.2	74.9
Distribution coverage ratio	1.00x	1.05x	1.09x	0.88x	1.00x

Production and Realized Pricing

	Three Months Ended December 31, (a)		Year Ended December 31, (a)	
	2013	2012	2013	2012 (b)
Average realized prices, excluding hedging:				
Oil (Price/Bbl)	$ 82.15	$ 80.98	$ 87.06	$ 84.53
Natural Gas (Price/Mcf)	$ 2.39	$ 2.37	$ 2.48	$ 2.41
NGLs (Price/Bbl)	$ 28.45	$ 42.74	$ 33.72	$ 45.11
Average realized prices, including hedging(c):				
Oil (Price/Bbl)	$ 78.69	$ 84.13	$ 82.26	$ 84.00
Natural Gas (Price/Mcf)	$ 3.41	$ 4.19	$ 3.39	$ 4.47
NGLs (Price/Bbl)	$ 28.25	$ 42.74	$ 33.76	$ 45.11
Average NYMEX prices				
Oil (Price/Bbl)	$ 97.50	$ 88.23	$ 98.04	$ 94.19
Natural Gas (Price/Mcf)	$ 3.60	$ 3.40	$ 3.66	$ 2.96
Total production volumes:				
Oil (MBbls)	773	697	3,089	2,758
Natural Gas (MMcf)	12,670	7,147	50,236	19,652
NGLs (MBbls)	511	210	1,477	664
Combined (MBOE)	3,395	2,098	12,938	6,697
Average daily production volumes:				
Oil (Bbls/day)	8,398	7,575	8,462	7,536
Natural Gas (Mcf/day)	137,722	77,688	137,632	53,695
NGLs (Bbls/day)	5,551	2,279	4,047	1,813
Combined (BOE/day)	36,903	22,803	35,448	18,298

(a) During 2013 and 2012, 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) On March 30, 2012, we divested oil and natural gas properties in the Appalachian Basin. As such, there are no operating results from these properties included in our operating results from the closing date of the divestiture forward.

(c) 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.

Statement of Operations

	Three Months Ended December 31, 2013	Three Months Ended December 31, 2012	Year Ended December 31, 2013	Year Ended December 31, 2012
Revenues:				
Oil sales	$ 63,468	$ 56,027	$ 268,922	$ 233,153
Natural gas sales	30,324	17,339	124,513	47,270
NGLs sales	14,527	8,961	49,813	29,933
Net gains (losses) on commodity derivative contracts	(350)	28,359	11,256	36,846
Total revenues	107,969	110,686	454,504	347,202
Costs and expenses:				
Production:				
Lease operating expenses	29,481	19,612	105,502	74,366
Production and other taxes	10,026	8,205	40,430	29,369
Depreciation, depletion, amortization and accretion	44,181	30,645	167,535	104,542
Impairment of oil and natural gas properties	—	229,693	—	247,722
Selling, general and administrative expenses	6,763	7,168	25,942	22,466
Total costs and expenses	90,451	295,323	339,409	478,465
Income (loss) from operations	17,518	(184,637)	115,095	(131,263)
Other income (expense):				
Other income	3	29	69	220
Interest expense	(14,915)	(14,343)	(61,148)	(41,891)
Net gains (losses) on interest rate derivative contracts	(494)	125	(96)	(6,992)
Net gain (loss) on acquisition of oil and natural gas properties	—	(2,685)	5,591	11,111
Total other expense	(15,406)	(16,874)	(55,584)	(37,552)
Net income (loss)	2,112	(201,511)	59,511	(168,815)
Less: Distributions to Preferred unitholders	(1,242)	—	(2,634)	—
Net income (loss) available to Common and Class B unitholders	$ 870	$ (201,511)	$ 56,877	$ (168,815)
Net income (loss) per Common and Class B unit				
Basic	$ 0.01	$ (3.41)	$ 0.78	$ (3.11)
Diluted	$ 0.01	$ (3.41)	$ 0.77	$ (3.11)
Weighted average units outstanding:				
Common units – basic	77,727	58,668	72,644	53,777
Common units – diluted	78,000	58,668	72,992	53,777
Class B units – basic & diluted	420	420	420	420

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Balance Sheet

	December 31, 2013	December 31, 2012
Assets	(Unaudited)	
Current assets		
Cash and cash equivalents	$ 11,818	$ 11,563
Trade accounts receivable, net	70,109	51,880
Derivative assets	21,314	46,690
Other currents assets	2,916	3,858
Total current assets	106,157	113,991
Oil and natural gas properties, at cost	2,523,671	2,126,268
Accumulated depletion, amortization and impairment	(713,154)	(550,032)
Oil and natural gas properties evaluated, net– full cost method	1,810,517	1,576,236
Other assets		
Goodwill	420,955	420,955
Derivative assets	60,474	53,240
Other assets	91,538	35,712
Total assets	$ 2,489,641	$ 2,200,134
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 9,824	$ 8,417
Affiliates	249	32
Accrued liabilities:		
Lease operating	12,882	7,884
Developmental capital	10,543	4,754
Interest	11,989	11,573
Production and other taxes	16,251	12,852
Derivative liabilities	10,992	5,366
Oil and natural gas revenue payable	23,245	8,226
Distributions payable	16,499	11,919
Other	12,929	8,479
Total current liabilities	125,403	79,502
Long-term debt	1,007,879	1,247,631
Derivative liabilities	4,085	11,996
Asset retirement obligations	82,208	60,096
Other long-term liabilities	1,731	3,445
Total liabilities	1,221,306	1,402,670
Commitments and contingencies		
Members' equity		
Preferred units, 2,535,927 units issued and outstanding at December 31, 2013	61,021	—
Members' capital, 78,337,259and 58,706,282 common units issued and outstanding at December 31, 2013 and 2012, respectively	1,205,311	794,426
Class B units, 420,000 issued and outstanding at December31, 2013 and 2012	2,003	3,038
Total members' equity	1,268,335	797,464
Total liabilities and members' equity	$ 2,489,641	$ 2,200,134

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