Supplemental Q3 2014 Earnings Results

VANGUARD
NATURAL RESOURCES, LLC
NASDAQ: VNR

THE MONTHLY DISTRIBUTION MLP™

Third Quarter 2014 Highlights

- Adjusted EBITDA (a non-GAAP financial measure defined below) increased 31% to $108.2 million in the third quarter of 2014 from $82.7 million in the third quarter of 2013 and increased 11% from the $97.7 million recorded in the second quarter of 2014.

- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined below) increased to $53.0 million from the $52.9 million generated in the third quarter of 2013 and increased 15% from the $46.1 million generated in the second quarter of 2014.

- Adjusted Net Income Attributable to Common and Class B Unitholders (a non-GAAP financial measure defined below) was $27.9 million in the third quarter of 2014, or $0.34 per basic unit, as compared to $22.6 million, or $0.29 per basic unit, in the third quarter of 2013 and $22.0 million, or $0.27 per basic unit, in the second quarter of 2014. The third quarter of 2014 includes net non-cash gains of $81.6 million that are adjustments to arrive at Adjusted Net Income Attributable to Common and Class B Unitholders. The third quarter of 2013 results included net non-cash losses of $20.6 million.

- Reported average production of 322 MMcfe per day in the third quarter of 2014, up 52% over 211 MMcfe per day produced in the third quarter of 2013 and a 2% increase over 315 MMcfe per day produced in the second quarter of 2014. On an Mcfe basis, crude oil, natural gas and natural gas liquids ("NGLs") accounted for 16%, 71%, and 13% of our third quarter 2014 production, respectively.

Selected Summary Financials

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	($ in thousands, except per unit data) (Unaudited)			
Production (MMcfe/d)	322	211	302	210
Oil, natural gas and natural gas liquids sales	$ 153,627	$ 121,510	$ 467,886	$ 334,929
Net gains (losses) on commodity derivative contracts	$ 83,311	$ (17,714)	$ (11,125)	$ 11,606
Operating expenses	$ 46,141	$ 36,436	$ 142,419	$ 106,425
Selling, general and administrative expenses	$ 7,140	$ 5,730	$ 23,042	$ 19,179
Depreciation, depletion, amortization, and accretion	$ 55,680	$ 41,750	$ 150,798	$ 123,354
Net Income Attributable to Common and Class B Unitholders	$ 109,150	$ 1,881	$ 112,975	$ 56,007
Adjusted Net Income Attributable to Common and Class B Unitholders (1)	$ 27,916	$ 22,601	$ 74,483	$ 58,591
Adjusted Net Income Attributable to Common and Class B Unitholders, per unit(1)	$ 0.34	$ 0.29	$ 0.92	$ 0.82
Adjusted EBITDA(1)	$ 108,245	$ 82,687	$ 295,796	$ 235,401
Interest expense, including settlements paid oninterest rate derivative contracts	$ 17,742	$ 15,819	$ 52,555	$ 49,129
Estimated maintenance capital expenditures	$ 32,566	$ 12,774	$ 92,716	$ 42,192
Distributions to Preferred unitholders	$ 4,949	$ 1,240	$ 11,507	$ 1,392
Distributable Cash Flow Available to Common and Class B Unitholders (1)	$ 52,988	$ 52,854	$ 140,968	$ 142,688
Distributable Cash Flow per common and Class B unit(1)	$ 0.63	$ 0.68	$ 1.73	$ 1.93
Common and Class B unit distribution coverage(1)	1.00x	1.09x	0.91x	1.05x
Weighted average common and Class B units outstanding at record date attributable to distribution period	83,768	77,918	81,663	73,766

(1) Non-GAAP financial measures. Please see Adjusted Net Income Attributable 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.

Commodity Hedge Summary (as of 10/31/14)

Percent Production Hedged

	October 1, - December 31, 2014	Year 2015	Year 2016	Year 2017
Gas Production Hedged:				
% Anticipated Production Hedged	77 %	81 %	62 %	36 %
% Proved Developed Producing Production Hedged	78 %	91 %	87 %	59 %
Weighted Average Price ($/MMBtu)	$ 4.40	$ 4.32	$ 4.37	$ 4.21
Oil Production Hedged:				
% Anticipated Production Hedged	84 %	70 %	31 %	2 %
% Proved Developed Producing Production Hedged	95 %	78 %	40 %	3 %
Weighted Average Price ($/Bbl)	$ 93.40	$ 91.95	$ 90.60	$ 86.60
NGLs Production Hedged:				
% Anticipated Production Hedged	7 %	6 %	—	—
% Proved Developed Producing Production Hedged	8 %	7 %	—	—
Weighted Average Price ($/Bbl)	$ 40.87	$ 46.34	$ —	$ —

Note: Hedge prices reflect a weighted average of swap prices, floor prices on collars and long put prices on three way collars. Weighted average floor price includes impact from the range bonus accumulators. Assumes capital spending in 2015 and beyond.

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	66,795,000	55,083,000	27,677,000
Fixed Price ($/MMBtu)	$4.43	$4.40	$4.47	$4.32
Three Way Collars:				
Notional Volume (Bbls)	3,370,000	17,337,500	12,810,000	12,775,000
Floor Price ($/Bbl)	$4.15	$3.99	$3.95	$3.97
Ceiling Price ($/Bbl)	$4.91	$4.67	$4.58	$4.61
Put Sold ($/Bbl)	$3.50	$3.38	$3.38	$3.40
Total:				
Notional Volume (MMBtu)	72,130,225	84,132,500	67,893,000	40,452,000
Fixed Price ($/MMBtu)	$4.42	$4.32	$4.37	$4.21
Basis Swaps:				
Northwest Rockies Pipeline - NYMEX				
Notional Volume (MMBtu)	26,875,000	29,200,000	18,300,000	10,950,000
Fixed Price ($/MMBtu)	($0.20)	($0.28)	($0.24)	($0.22)
CIG Rockies - NYMEX				
Notional Volume (MMBtu)	452,500	-	-	-
Fixed Price ($/MMBtu)	($0.32)	-	-	-
Puts Sold:				
Notional Volume (MMBtu)	3,340,000	9,125,000	1,830,000	1,825,000
Fixed Price ($/MMBtu)	$3.50	$3.50	$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 updated as of October 31, 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)	$116.20	-	-	-
Three Way Collars:				
Notional Volume (Bbls)	1,313,850	1,984,055	1,061,400	-
Floor Price ($/Bbl)	$93.47	$91.84	$90.00	-
Ceiling Price ($/Bbl)	$101.25	$99.45	$96.18	-
Put Sold ($/Bbl)	$72.57	$74.41	$73.62	-
Total:				
Notional Volume (Bbls)	3,141,725	2,676,055	1,207,800	73,000
Fixed Price ($/Bbl)	$93.38	$91.95	$90.60	$86.60
Basis Swaps:				
Midland-Cushing				
Notional Volume (Bbls)	584,000	365,000	-	-
Fixed Price ($/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)	($3.95)	-	-	-
Swaptions and Calls:				
Notional Volume (Bbls)	492,750	598,945	622,200	-
Fixed Price ($/Bbl)	$104.80	$104.32	$125.00	-
Puts Sold:				
Notional Volume (Bbls)	73,000	692,000	146,400	73,000
Put Sold ($/Bbl)	$75.00	$72.36	$75.00	$75.00
Range Bonus Accumulators:				
Notional Volume (Bbl)	912,500	182,500	183,000	-
Bonus ($/Bbl)	$4.94	$4.00	$4.00	-
Range Ceiling ($/Bbl)	$103.20	$100.00	$100.00	-
Range Floor ($/Bbl)	$70.50	$75.00	$75.00	-

Note: Weighted average floor price includes impact from the range bonus accumulators. Hedge positions updated as of October 31, 2014.

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)	$11.03	-	-	-
Mont Belviu Propane				
Notional Volume (Bbls)	144,157	164,250	-	-
Fixed Price ($/Bbl)	$40.50	$43.21	-	-
Mont Belviu N. Butane				
Notional Volume (Bbls)	15,075	36,500	-	-
Fixed Price ($/Bbl)	$65.62	$52.08	-	-
Mont Belviu Isobutane				
Notional Volume (Bbls)	16,078	45,625	-	-
Fixed Price ($/Bbl)	$70.24	$53.00	-	-
Mont Belviu N. Gasoline				
Notional Volume (Bbls)	27,667	-	-	-
Fixed Price ($/Bbl)	$88.57	-	-	-
Total				
Notional Volume (Bbls)	273,750	246,375	-	-
Fixed Price ($/Bbl)	$40.87	$46.34	-	-

Note: Hedge positions updated as of October 31, 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, 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 changes in the fair value of our derivative contracts. Adjusted Net Income Attributable 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, operating income, 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 September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Net income	$ 114,099	$ 3,121	$ 124,482	$ 57,399
Plus:				
Interest expense	16,721	14,832	49,529	46,233
Depreciation, depletion, amortization, and accretion	55,680	41,750	150,798	123,354
Net (gains) losses on commodity derivative contracts	(83,311)	17,714	11,125	(11,606)
Cash settlements on matured commodity derivative (b)(c)	6,033	2,141	(13,347)	20,862
Net (gains) losses on interest rate derivative contracts (d)	(511)	1,729	1,068	(398)
Net (gains) losses on acquisitions of oil and natural gas properties	(2,409)	236	(34,523)	(5,591)
Texas margin taxes	156	101	(125)	(140)
Compensation related items	1,438	942	6,440	4,445
Material transaction costs incurred on acquisitions	349	121	349	843
Adjusted EBITDA	$ 108,245	$ 82,687	$ 295,796	$ 235,401
Less:				
Interest expense, including settlements paid on interest rate derivatives	(17,742)	(15,819)	(52,555)	(49,129)
Estimated maintenance capital expenditures (e)	(32,566)	(12,774)	(92,716)	(42,192)
Distributions to Preferred unitholders	(4,949)	(1,240)	(11,507)	(1,392)
Proceeds from sale of leasehold interests	—	—	1,950	—
Distributable Cash Flow Available to Common and Class B Unitholders	**$ 52,988**	**$ 52,854**	**$ 140,968**	**$ 142,688**
Distributions to Common and Class B unitholders	52,774	48,504	154,139	136,099
Excess (shortfall) of distributable cash flow after distributions to unitholders	**$ 214**	**$ 4,350**	**$ (13,171)**	**$ 6,589**
Distributable Cash Flow per Common and Class B unit	$ 0.63	$ 0.68	$ 1.73	$ 1.93
Common and Class B unit Distribution Coverage	1.00x	1.09x	0.91x	1.05x

(a) Our Adjusted EBITDA should not be considered as an alternative to 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.

(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.	$ —	$ 56	$ —	$ 165
(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.	$ 5,608	$ 7,444	$ 16,472	$ 22,872
(d) Includes settlements paid on interest rate derivatives	$ 1,021	$ 987	$ 3,026	$ 2,896

(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 pries 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.

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Adjusted Net Income

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Net Income Attributable to Common and Class B Unitholders	$ 109,150	$ 1,881	$ 112,975	$ 56,007
Plus (less):				
Change in fair value of commodity derivative contracts	(82,886)	12,355	(18,694)	(13,781)
Change in fair value of interest rate derivative contracts	(1,532)	742	(1,958)	(3,294)
Unrealized fair value of phantom units granted to officers	(364)	(178)	(138)	1,535
Fair value of derivative contracts acquired that apply to contracts settled during the period	5,608	7,444	16,472	22,872
Net (gains) losses on acquisitions of oil and natural gas properties	(2,409)	236	(34,523)	(5,591)
Material transaction costs incurred on acquisitions	349	121	349	843
Adjusted Net Income Attributable to Common and Class B Unitholders	$ 27,916	$ 22,601	$ 74,483	$ 58,591
Net Income Attributable to Common and Class B Unitholders, per unit	$ 1.31	$ 0.02	$ 1.39	$ 0.78
Plus (less):				
Change in fair value of commodity derivative contracts	(0.99)	0.16	(0.23)	(0.19)
Change in fair value of interest rate derivative contracts	(0.02)	0.01	(0.02)	(0.04)
Unrealized fair value on phantom units granted to officers	—	—	—	0.02
Fair value of derivative contracts acquired that apply to contracts settled during the period	0.07	0.10	0.20	0.32
Net (gains) losses on acquisitions of oil and natural gas properties	(0.03)	—	(0.42)	(0.08)
Material transaction costs incurred on acquisitions	—	—	—	0.01
Adjusted Net Income Attributable to Common and Class B Unitholders, per unit	$ 0.34	$ 0.29	$ 0.92	$ 0.82
Weighted average common and Class B units outstanding	83,525	77,903	81,377	71,351

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
Adjusted EBITDA	$89,863	$97,690	$108,245
Interest expense, net	(17,249)	(17,564)	(17,742)
Maintenance capital expenditures	(28,814)	(31,337)	(32,566)
Distributions to preferred unitholders	(1,962)	(4,596)	(4,949)
Proceeds from the sale of leasehold interests	-	1,950	-
Distributable cash flow	$41,838	$46,143	$52,988
Distributable cash flow per unit	$0.5238	$0.5673	$0.6326
Distribution per unit	$0.6275	$0.6300	$0.6300
Units outstanding (millions)	79.9	81.3	83.8
Distribution coverage ratio	0.83x	0.90x	1.00x

Production and Realized Pricing

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Average realized prices, excluding hedges:				
Oil (Price/Bbl)	$ 84.96	$ 97.38	$ 88.23	$ 88.70
Natural Gas (Price/Mcf)	$ 3.24	$ 2.47	$ 3.55	$ 2.51
NGLs (Price/Bbl)	$ 26.66	$ 35.51	$ 29.26	$ 36.51
Average realized prices, including hedges(b):				
Oil (Price/Bbl)	$ 84.36	$ 84.37	$ 84.36	$ 83.45
Natural Gas (Price/Mcf)	$ 3.55	$ 3.48	$ 3.49	$ 3.38
NGLs (Price/Bbl)	$ 26.70	$ 35.56	$ 28.98	$ 36.68
Average NYMEX prices:				
Oil Price (Price/Bbl)	$ 97.13	$ 105.82	$ 99.62	$ 98.22
Natural Gas Price (Price/Mcf)	$ 4.07	$ 3.57	$ 4.57	$ 3.68
Total production volumes:				
Oil (MBbls)	813	793	2,394	2,316
Natural Gas (MMcf)	20,962	12,398	56,651	37,565
NGLs (MBbls)	629	383	1,897	966
Combined (MMcfe)	29,610	19,458	82,396	57,260
Average daily production volumes:				
Oil (Bbls/day)	8,832	8,621	8,769	8,484
Natural Gas (MMcf/day)	228	135	208	138
NGLs (Bbls/day)	6,835	4,168	6,949	3,540
Combined (MMcfe/day)	322	211	302	210

(a) During 2014 and 2013, we acquired certain oil and natural gas properties and related assets. The operating results of these properties are included from the closing date of the 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 September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues:				
Oil sales	$ 69,034	$ 77,236	$ 211,197	$ 205,454
Natural gas sales	67,827	30,655	201,175	94,189
NGLs sales	16,766	13,619	55,514	35,286
Net gains (losses) on commodity derivative contracts	83,311	(17,714)	(11,125)	11,606
Total revenues	236,938	103,796	456,761	346,535
Costs and expenses:				
Production:				
Lease operating expenses	31,011	25,339	95,726	76,021
Production and other taxes	15,130	11,097	46,693	30,404
Depreciation, depletion, amortization, and accretion	55,680	41,750	150,798	123,354
Selling, general and administrative expenses	7,140	5,730	23,042	19,179
Total costs and expenses	108,961	83,916	316,259	248,958
Income from operations	127,977	19,880	140,502	97,577
Other income (expense):				
Interest expense	(16,721)	(14,832)	(49,529)	(46,233)
Net gains (losses) on interest rate derivative contracts	511	(1,729)	(1,068)	398
Net gains (losses) on acquisitions of oil and natural gas	2,409	(236)	34,523	5,591
Other	(77)	38	54	66
Total other expense	(13,878)	(16,759)	(16,020)	(40,178)
Net income	$ 114,099	$ 3,121	$ 124,482	$ 57,399
Distributions to Preferred unitholders	(4,949)	(1,240)	(11,507)	(1,392)
Net income attributable to Common and Class B unitholders	$ 109,150	$ 1,881	$ 112,975	$ 56,007
Net income per Common and Class B units				
Basic	$ 1.31	$ 0.02	$ 1.39	$ 0.78
Diluted	$ 1.30	$ 0.02	$ 1.38	$ 0.78
Weighted average Common units outstanding				
Common units – basic	83,105	77,483	80,957	70,931
Common units – diluted	83,333	77,748	81,231	71,361
Class B units – basic & diluted	420	420	420	420

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Balance Sheets

	September 30, 2014	December 31, 2013
Assets		
Current assets		
Cash and cash equivalents	$ 43,956	$ 11,818
Trade accounts receivable, net	102,357	70,109
Derivative assets	38,967	21,314
Other current assets	4,591	2,916
Total current assets	189,871	106,157
Oil and natural gas properties, at cost	4,077,926	2,523,671
Accumulated depletion, amortization and impairment	(858,608)	(713,154)
Oil and natural gas properties evaluated, net– full cost method	3,219,318	1,810,517
Other assets		
Goodwill	420,955	420,955
Derivative assets	37,287	60,474
Other assets	28,357	91,538
Total assets	$ 3,895,788	$ 2,489,641
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 10,258	$ 9,824
Affiliates	580	249
Accrued liabilities:		
Lease operating	17,192	12,882
Development capital	32,716	10,543
Interest	22,551	11,989
Production and other taxes	28,831	16,251
Derivative liabilities	4,179	10,992
Oil and natural gas revenue payable	31,260	23,245
Distribution payable	18,662	16,499
Other	15,970	12,929
Total current liabilities	182,199	125,403
Long-term debt	1,923,078	1,007,879
Derivative liabilities	2,528	4,085
Asset retirement obligations, net of current portion	132,987	82,208
Other long-term liabilities	—	1,731
Total liabilities	2,240,792	1,221,306
Commitments and contingencies		
Members' equity		
Cumulative Preferred units, 13,881,873 units issued and outstanding at September 30, 2014 and 2,535,927 at December 31, 2013	335,542	61,021
Common units, 83,559,668 units issued and outstanding at September 30, 2014 and 78,337,259 at December 31, 2013	1,311,839	1,199,699
Class B units, 420,000 issued and outstanding at September 30, 2014 and December 31, 2013	7,615	7,615
Total members' equity	1,654,996	1,268,335
Total liabilities and members' equity	$ 3,895,788	$ 2,489,641