Supplemental Q2 2015 Earnings Results

VANGUARD
NATURAL RESOURCES, LLC
NASDAQ: VNR

THE MONTHLY DISTRIBUTION MLP™

Second Quarter 2015 Highlights

- Adjusted EBITDA (a non-GAAP financial measure defined later) decreased 7% to $90.6 million in the second quarter of 2015 from $97.7 million in the second quarter of 2014 and increased 6% from the $85.3 million recorded in the first quarter of 2015.
- Distributable Cash Flow Available to Common and Class B Unitholders (a non-GAAP financial measure defined later) decreased to $35.5 million from the $46.1 million generated in the second quarter of 2014 and increased 10% from the $32.4 million generated in the first quarter of 2015.
- Adjusted Net Loss Attributable to Common and Class B Unitholders (a non-GAAP financial measure defined later) was $6.6 million in the second quarter of 2015, or $0.07 per basic unit, as compared to Adjusted Net Income of $22.0 million, or $0.27 per basic unit, in the second quarter of 2014 and $18.0 million, or $0.21 per basic unit, in the first quarter of 2015. The second quarter of 2015 includes net non-cash expenses of $793.7 million that are adjustments to arrive at Adjusted Net Income Attributable to Common and Class B Unitholders. The second quarter 2015 adjustments include a $733.4 million impairment charge on our oil and gas properties. The second quarter of 2014 results included net non-cash losses of $31.3 million.

Selected Summary Financials

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	($ in thousands, except per unit data) (Unaudited)			
Production (MMcfe/d)	368	315	381	292
Oil, natural gas and natural gas liquids sales	$ 95,841	$ 161,519	$ 194,735	$ 314,259
Net gains (losses) on commodity derivative contracts	$ (20,800)	$ (38,398)	$ 38,233	$ (94,436)
Operating expenses	$ 42,354	$ 50,822	$ 89,258	$ 96,278
Selling, general and administrative expenses	$ 9,142	$ 7,864	$ 18,193	$ 15,902
Depreciation, depletion, amortization, and accretion	$ 63,175	$ 51,508	$ 130,015	$ 95,118
Impairment of oil and natural gas properties	$ 733,365	$ —	$ 865,975	$ —
Net income (loss) attributable to Common and Class B unitholders	$ (800,335)	$ (9,333)	$ (925,855)	$ 3,825
Adjusted Net Income (Loss) Attributable to Common and Class B Unitholders [(1)]	$ (6,597)	$ 21,965	$ 11,389	$ 46,568
Adjusted Net Income (Loss) Attributable to Common and Class B Unitholders, per unit[(1)]	$ (0.07)	$ 0.27	$ 0.13	$ 0.59
Adjusted EBITDA[(1)]	$ 90,579	$ 97,690	$ 175,918	$ 187,552
Interest expense, including settlements paid on interest rate derivative contracts	$ 21,364	$ 17,564	$ 42,543	$ 34,813
Estimated maintenance capital expenditures	$ 27,031	$ 31,337	$ 52,100	$ 60,151
Distributions to Preferred unitholders	$ 6,690	$ 4,596	$ 13,380	$ 6,558
Distributable Cash Flow Available to Common and Class B Unitholders[(1)]	$ 35,494	$ 46,143	$ 67,895	$ 87,980
Distributable Cash Flow per common and Class B unit[(1)]	$ 0.41	$ 0.57	$ 0.79	$ 1.09
Common and Class B unit distribution coverage[(1)]	1.16x	0.90x	1.13x	0.87x
Weighted average common and Class B units outstanding at record date attributable to distribution period	86,545	81,344	85,505	80,608

(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 presentation for a reconciliation of these measures to their nearest comparable GAAP measure.

Commodity Hedge Summary (as of 7/1/15)

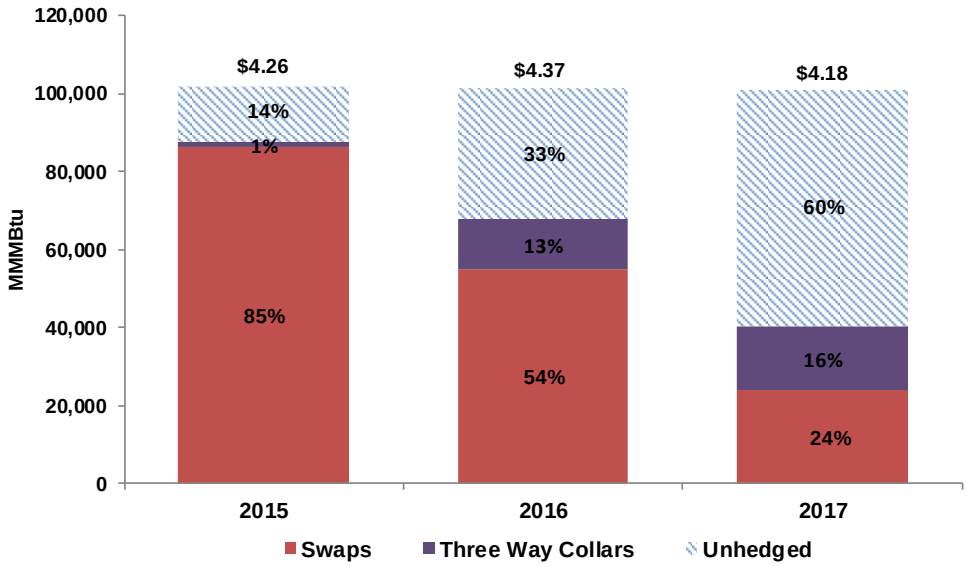
Percent Production Hedged

	July 1 - December 31, 2015	Year 2016	Year 2017
Gas Production Hedged:			
% Anticipated Production Hedged	88%	67%	40%
Weighted Average Price ($/MMBtu)	$ 4.24	$ 4.37	$ 4.18
Oil Production Hedged:			
% Anticipated Production Hedged	84%	50%	—%
Weighted Average Price ($/Bbl)	$ 71.58	$ 81.14	$ —
NGLs Production Hedged:			
% Anticipated Production Hedged	9%	22%	—%
Weighted Average Price ($/Bbl)	$ 46.34	$ 29.96	$ —

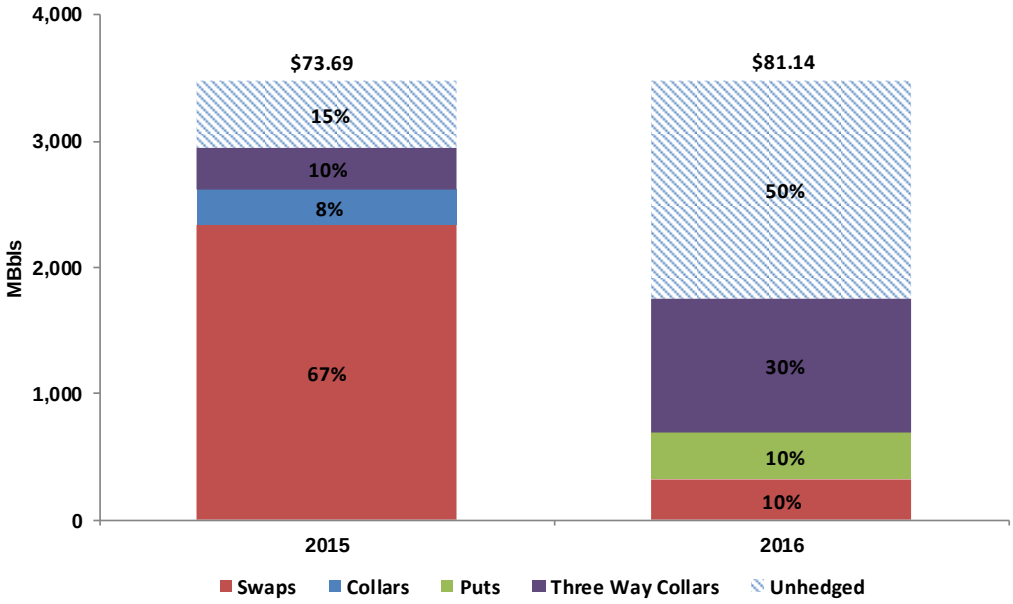
Note: Hedge prices reflect a weighted average of swap prices, long put prices and long put prices on three way collars. The impact of the pending mergers with LRE and EROC are not included in the amounts or percentages shown.

Commodity Hedge Summary (as of 7/30/15)

Natural Gas Hedges (Full Year)



Oil Hedges (Full Year)



Note: Hedge prices reflect a weighted average of swap prices, long put prices and long put prices on three way collars. The impact of the pending mergers with LRE and EROC are not included in the amounts or percentages shown.

VANGUARD NATURAL RESOURCES, LLC NASDAQ: VNR

Natural Gas Hedge Positions (Q3 2015 - 2017)

	July 1 - Dec 31, 2015	Year 2016	Year 2017
Natural Gas Positions:			
Fixed Price Swaps:			
Notional Volume (MMBtu)	45,172,000	55,083,000	24,027,000
Fixed Price ($/MMBtu)	$4.24	$4.47	$4.35
Three Way Collars:			
Notional Volume (MMBtu)	-	12,810,000	16,425,000
Floor Price ($/MMBtu)	-	$3.95	$3.92
Ceiling Price ($/MMBtu)	-	$4.25	$4.23
Put Sold ($/MMBtu)	-	$3.00	$3.37
Total:			
Notional Volume (MMBtu)	45,172,000	67,893,000	40,452,000
Weighted Average Price ($/MMBtu)	$4.24	$4.37	$4.18
Basis Swaps:			
Notional Volume (MMBtu)	14,720,000	18,300,000	10,950,000
Fixed Price ($/MMBtu)	($0.28)	($0.24)	($0.22)
Puts Sold:			
Notional Volume (MMBtu)	13,340,000	1,830,000	1,825,000
Weighted Average Price ($/MMBtu)	$3.03	$3.00	$3.50
Range Bonus Accumulators:			
Notional Volume (MMBtu)	736,000	-	-
Bonus ($/MMBtu)	$0.16	-	-
Range Ceiling ($/MMBtu)	$4.00	-	-
Range Floor ($/MMBtu)	$2.50	-	-

Note: Hedge positions updated as of July 30, 2015. The impact of the pending mergers with LRE and EROC are not included in the amounts or percentages shown .

Oil Hedge Positions (Q3 2015 - 2017)

Oil Positions:	July 1 - Dec 31, 2015	Year 2016	Year 2017
Fixed Price Swaps:			
Notional Volume (Bbls)	1,205,200	329,400	-
Fixed Price ($/Bbl)	$71.94	$76.10	-
Puts:			
Notional Volume (Bbls)	-	366,000	-
Floor Price ($/Bbl)	-	$60.00	-
Three Way Collars:			
Notional Volume (Bbls)	138,000	1,061,400	-
Floor Price ($/Bbl)	$90.00	$90.00	-
Ceiling Price ($/Bbl)	$97.35	$96.18	-
Put Sold ($/Bbl)	$76.67	$73.62	-
Total:			
Notional Volume (Bbls)	1,481,200	1,756,800	-
Weighted Average Price ($/Bbl)	$71.58	$81.14	-
Basis Swaps:			
Midland-Cushing			
Notional Volume (Bbls)	257,600	512,400	-
Fixed Price ($/Bbl)	($1.68)	($0.94)	-
WTS-Cushing			
Notional Volume (Bbls)	73,600	219,600	-
Fixed Price ($/Bbl)	($2.33)	($0.43)	-
WTI-WCS			
Notional Volume (Bbls)	368,000	-	-
Fixed Price ($/Bbl)	($14.50)	-	-
Calls Sold:			
Notional Volume (Bbls)	36,800	622,200	365,000
Short Call Price ($/Bbl)	$105.00	$125.00	$95.00
Call Spread:			
Notional Volume (Bbls)	947,600	-	-
Call Price ($/Bbl)	$70.00	-	-
Short Call Price ($/Bbl)	$85.00	-	-
Puts Sold:			
Notional Volume (Bbls)	257,600	146,400	73,000
Weighted Average Price ($/Bbl)	$71.43	$75.00	$75.00
Range Bonus Accumulators:			
Notional Volume (Bbl)	92,000	183,000	-
Bonus ($/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 July 30, 2015. The impact of the pending mergers with LRE and EROC are not included in the amounts or percentages shown.

NGL Hedge Positions (Q3 2015 - 2017)

	July 1 - Dec 31, 2015	Year 2016	Year 2017
Natural Gas Liquids:			
Fixed Price Swaps			
Mont Belviu Ethane			
Notional Volume (Bbls)	-	-	-
Fixed Price ($/Bbl)	-	-	-
Mont Belviu Propane			
Notional Volume (Bbls)	82,800	274,500	-
Fixed Price ($/Bbl)	$43.21	$22.40	-
Mont Belviu N. Butane			
Notional Volume (Bbls)	18,400	128,100	-
Fixed Price ($/Bbl)	$52.08	$27.63	-
Mont Belviu Isobutane			
Notional Volume (Bbls)	23,000	54,900	-
Fixed Price ($/Bbl)	$53.00	$27.20	-
Mont Belviu N. Gasoline			
Notional Volume (Bbls)	-	109,800	-
Fixed Price ($/Bbl)	-	$52.97	-
Total			
Notional Volume (Bbls)	124,200	567,300	-
Fixed Price ($/Bbl)	$46.34	$29.96	-

Note: Hedge positions updated as of July 30, 2015. The impact of the pending mergers with LRE and EROC are not included in the amounts or percentages shown.

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, 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 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 (loss), 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 (loss), 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net income (loss)	$ (793,645)	$ (4,737)	$ (912,475)	$ 10,383
Plus:				
Interest expense	20,374	16,549	40,563	32,808
Depreciation, depletion, amortization, and accretion	63,175	51,508	130,015	95,118
Impairment of oil and natural gas properties	733,365	—	865,975	—
Net (gains) losses on commodity derivative contracts	20,800	38,398	(38,233)	94,436
Cash settlements on matured commodity derivative contracts[(b)(c)(d)]	42,329	(7,410)	80,620	(19,380)
Net losses on interest rate derivative contracts[(e)]	281	1,121	1,484	1,579
Gain on acquisition of oil and natural gas properties	—	—	—	(32,114)
Texas margin taxes	34	130	142	(281)
Compensation related items	3,866	2,131	7,827	5,003
Adjusted EBITDA	$ 90,579	$ 97,690	$ 175,918	$ 187,552
Less:				
Interest expense, including settlements paid on interest rate derivatives	(21,364)	(17,564)	(42,543)	(34,813)
Estimated maintenance capital expenditures[(f)]	(27,031)	(31,337)	(52,100)	(60,151)
Distributions to Preferred unitholders	(6,690)	(4,596)	(13,380)	(6,558)
Proceeds from sale of leasehold interests	—	1,950	—	1,950
Distributable Cash Flow Available to Common and Class B Unitholders	**$ 35,494**	**$ 46,143**	**$ 67,895**	**$ 87,980**
Distributions to Common and Class B unitholders	30,507	51,247	60,281	101,365
Excess (shortfall) of distributable cash flow after distributions to unitholders	**$ 4,987**	**$ (5,104)**	**$ 7,614**	**$ (13,385)**
Distributable Cash Flow per Common and Class B unit	$ 0.41	$ 0.57	$ 0.79	$ 1.09
Common and Class B unit Distribution Coverage	1.16x	0.90x	1.13x	0.87x

(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.	$ 2,047	$ —	$ 2,567	$ —
(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. Also excludes the fair value of derivative contracts acquired and settled during the period.	$ 11,732	$ 5,983	$ 20,281	$ 10,864
(d) Excludes fair value of restructured derivative contracts.	$ —	$ —	$ (31,945)	$ —
(e) Includes settlements paid on interest rate derivatives.	$ 990	$ 1,015	$ 1,980	$ 2,005

(f) Estimated maintenance capital expenditures are intended to represent the amount of capital required to offset the decrease in production from the prior year due to 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 production from 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 production. Further, because estimated maintenance capital expenditures are not intended to target specific levels of reserves, if we do not acquire new proved or unproved reserves, our total reserves will decrease over time and we would be unable to sustain production at current levels, which could adversely affect our ability to pay a distribution at the current level or at all.

Adjusted Net Income

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Net Income (Loss) Attributable to Common and Class B Unitholders	$ (800,335)	$ (9,333)	$ (925,855)	$ 3,825
Plus (less):				
Change in fair value of commodity derivative contracts	49,350	25,005	51,484	64,192
Change in fair value of interest rate derivative contracts	(709)	106	(496)	(426)
Unrealized fair value of phantom units granted to officers	—	204	—	227
Fair value of derivative contracts acquired that apply to contracts settled during the period	11,732	5,983	20,281	10,864
Gain on acquisition of oil and natural gas properties	—	—	—	(32,114)
Impairment of oil and natural gas properties	733,365	—	865,975	—
Adjusted Net Income (Loss) Attributable to Common and Class B Unitholders	$ (6,597)	$ 21,965	$ 11,389	$ 46,568
Net Income (Loss) Attributable to Common and Class B Unitholders, per unit	$ (9.27)	$ (0.12)	$ (10.86)	$ 0.05
Plus (less):				
Change in fair value of commodity derivative contracts	0.57	0.31	0.60	0.80
Change in fair value of interest rate derivative contracts	(0.01)	—	(0.01)	(0.01)
Unrealized fair value on phantom units granted to officers	—	—	—	—
Fair value of derivative contracts acquired that apply to contracts settled during the period	0.14	0.08	0.24	0.15
Gain on acquisition of oil and natural gas properties	—	—	—	(0.40)
Impairment of oil and natural gas properties	8.50	—	10.16	—
Adjusted Net Income (Loss) Attributable to Common and Class B Unitholders, per unit	$ (0.07)	$ 0.27	$ 0.13	$ 0.59
Weighted average common and Class B units outstanding	86,295	80,956	85,236	80,285

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	
	3/31/15	6/30/15
Adjusted EBITDA	$85,339	$90,579
Interest expense, net	(21,179)	(21,364)
Maintenance capital expenditures	(25,069)	(27,031)
Distributions to preferred unitholders	(6,690)	(6,690)
Distributable cash flow	$32,401	$35,494
Distributable cash flow per unit	$0.38	$0.41
Distribution per unit	$0.3525	$0.3525
Units outstanding (millions)	84.5	86.5
Distribution coverage ratio	1.09x	1.16x

Production and Realized Pricing

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014 [a]	Percentage Increase / (Decrease)	Three Months Ended March 31, 2015	Percentage Increase / (Decrease)
Total production volumes:					
Oil (MBbls)	866	806	7 %	850	2 %
Natural Gas (MMcf)	23,543	19,649	20 %	26,860	(12)%
NGLs (MBbls)	796	696	14 %	588	35 %
Combined (MMcfe)	33,514	28,664	17 %	35,489	(7)%
Average daily production volumes:					
Oil (Bbls/day)	9,511	8,860	7 %	9,442	2 %
Natural Gas (MMcf/day)	259	216	20 %	298	(12)%
NGLs (Bbls/day)	8,751	7,652	14 %	6,537	35 %
Combined (MMcfe/day)	368	315	17 %	394	(7)%
Average realized prices, excluding hedges:					
Oil (Price/Bbl)	$ 50.85	$ 91.74	(45)%	$ 42.12	21 %
Natural Gas (Price/Mcf)	$ 1.69	$ 3.55	(52)%	$ 2.08	(19)%
NGLs (Price/Bbl)	$ 14.98	$ 25.49	(41)%	$ 12.49	20 %
Average realized prices, including hedges[b]:					
Oil (Price/Bbl)	$ 58.02	$ 84.40	(31)%	$ 54.71	6 %
Natural Gas (Price/Mcf)	$ 3.16	$ 3.48	(9)%	$ 3.05	4 %
NGLs (Price/Bbl)	$ 16.93	$ 25.37	(33)%	$ 14.76	15 %
Average NYMEX prices:					
Oil (Price/Bbl)	$ 57.94	$ 103.01	(44)%	$ 48.59	19 %
Natural Gas (Price/Mcf)	$ 2.63	$ 4.67	(44)%	$ 2.98	(12)%

(a) During 2014, 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 June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Revenues:				
Oil sales	$ 44,011	$ 73,963	$ 79,801	$ 142,163
Natural gas sales	39,897	69,806	95,651	133,348
NGLs sales	11,933	17,750	19,283	38,748
Net gains (losses) on commodity derivative contracts	(20,800)	(38,398)	38,233	(94,436)
Total revenues	75,041	123,121	232,968	219,823
Costs and expenses:				
Production:				
Lease operating expenses	31,600	34,293	67,078	64,715
Production and other taxes	10,754	16,529	22,180	31,563
Depreciation, depletion, amortization, and accretion	63,175	51,508	130,015	95,118
Impairment of oil and natural gas properties	733,365	—	865,975	—
Selling, general and administrative expenses	9,142	7,864	18,193	15,902
Total costs and expenses	848,036	110,194	1,103,441	207,298
Income (loss) from operations	(772,995)	12,927	(870,473)	12,525
Other income (expense):				
Interest expense	(20,374)	(16,549)	(40,563)	(32,808)
Net losses on interest rate derivative contracts	(281)	(1,121)	(1,484)	(1,579)
Gain on acquisition of oil and natural gas properties	—	—	—	32,114
Other	5	6	45	131
Total other income (expense)	(20,650)	(17,664)	(42,002)	(2,142)
Net income (loss)	$ (793,645)	$ (4,737)	$ (912,475)	$ 10,383
Distributions to Preferred unitholders	(6,690)	(4,596)	(13,380)	(6,558)
Net income (loss) attributable to Common and Class B unitholders	$ (800,335)	$ (9,333)	$ (925,855)	$ 3,825
Net income (loss) per Common and Class B unit – basic and diluted	$ (9.27)	$ (0.12)	$ (10.86)	$ 0.05
Weighted average Common units outstanding				
Common units – basic & diluted	85,875	80,536	84,816	79,865
Class B units – basic & diluted	420	420	420	420

Balance Sheets

	June 30, 2015	December 31, 2014
Assets		
Current assets		
Cash and cash equivalents	$ 4,132	$ —
Trade accounts receivable, net	85,754	140,017
Derivative assets	114,415	142,114
Other current assets	6,146	4,102
Total current assets	210,447	286,233
Oil and natural gas properties, at cost	4,194,888	4,140,527
Accumulated depletion, amortization and impairment	(2,154,462)	(1,164,721)
Oil and natural gas properties evaluated, net– full cost method	2,040,426	2,975,806
Other assets		
Goodwill	420,955	420,955
Derivative assets	68,942	83,583
Other assets	27,272	27,015
Total assets	$ 2,768,042	$ 3,793,592
Liabilities and members' equity		
Current liabilities		
Accounts payable:		
Trade	$ 12,165	$ 15,118
Affiliates	1,266	823
Accrued liabilities:		
Lease operating	16,434	19,822
Development capital	9,938	24,706
Interest	11,502	11,517
Production and other taxes	41,397	29,981
Derivative liabilities	750	3,583
Oil and natural gas revenue payable	29,579	40,117
Distribution payable	11,226	18,640
Other	14,892	14,297
Total current liabilities	149,149	178,604
Long-term debt	1,890,731	1,932,816
Derivative liabilities	66	1,380
Asset retirement obligations, net of current portion	148,997	146,676
Other long-term liabilities	1,460	—
Total liabilities	2,190,403	2,259,476
Commitments and contingencies		
Members' equity		
Cumulative Preferred units, 13,881,873 units issued and outstanding at June30, 2015 and December 31, 2014	335,444	335,444
Common units, 86,404,830 units issued and outstanding at June30, 2015 and 83,451,746 at December 31, 2014	234,580	1,191,057
Class B units, 420,000 issued and outstanding at June30, 2015 and December 31, 2014	7,615	7,615
Total members' equity	577,639	1,534,116
Total liabilities and members' equity	$ 2,768,042	$ 3,793,592