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Vanguard Natural Resources, LLC
5487 San Felipe, Suite 3000
Houston, Texas 77057

May 27, 2016

VIA EDGAR

U.S. Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, DC 20549

Attention: H. Roger Schwall, Assistant Director
Ethan Horowitz, Accounting Branch Chief
Sandra Eisen, Staff Accountant
Lisa Krestynick, Staff Attorney

Re: Vanguard Natural Resources, LLC
Form 10-K for Fiscal Year Ended December 31, 2015
Filed March 8, 2016
File No. 1-33756

Dear Mr. Schwall:

This letter sets forth the responses of Vanguard Natural Resources, LLC, a Delaware limited liability company (the "***Company,***" "***Vanguard,***" "***We,***" "***Us***" or "***Our***"), to the comment letter from the staff (the "***Staff***") of the Division of Corporation Finance of the Securities and Exchange Commission (the "***Commission***"), dated April 22, 2016, relating to the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2015 (the "***Form 10-K***"), which was filed with the Commission on March 8, 2016.

In this letter, for your convenience, we have recited the comments from the Staff in italicized, bold type and have followed each comment with the Company's response thereto.

Based on our review of the Staff's comment letter, and as further described herein, we believe that the Form 10-K is materially accurate and, accordingly, that amendment is not necessary. As further detailed below, we have proposed updates to our disclosure to be made in future filings with the Commission.

With respect to comments 2, 5, 7 and 8 hereof, we are supplementally providing additional information in a separate confidential letter (the "Supplemental Letter") to the Staff pursuant to Rule 83 of the Commission's Rules on Information and Requests, 17 C.F.R. § 200.83.

Form 10-K for Fiscal Year Ended December 31, 2015

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Oil, Natural Gas and NGLs Data, page 9

Proved Undeveloped Reserves, page 12

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1. ***Your response to prior comment 5 explains the reasons underlying the positive revisions of previous volume estimates to your proved undeveloped reserves ("PUDs") during the fiscal year ended December 31, 2015. Please revise to provide additional disclosure explaining these changes consistent with the information provided in your response. Refer to Item 1203(b) of Regulation S-K.***

Response:

We acknowledge the Staff's comment. To address this comment, in future annual reports on Form 10-K, we will disclose additional information providing the reasons underlying any material revisions of prior year estimates to our PUDs that occurred during the year similar to the following (certain text from the Form 10-K has been rearranged and, with the exception of the heading, changes are reflected in **bold** type):

Proved Undeveloped Reserves

Our proved undeveloped reserves at December 31, 2015, as estimated by our internal reserve engineers, were 636.5 Bcfe, consisting of 9.1 MMBbls of oil, 484.2 Bcf of natural gas and 16.2 MMBbls of NGLs. Our proved undeveloped reserves decreased by 17.2 Bcfe during the year ended December 31, 2015, as compared to our proved undeveloped reserves as of December 31, 2015. The following table represents a summary of our proved undeveloped reserves activity during the year ended December 31, 2015:

	(in Bcfe)
PUDs at January 1, 2015	*653.7*
Acquisitions	*123.4*
Revisions of prior estimates	*(62.20)*
Conversion to developed	*(78.40)*
PUDs at December 31, 2015	*636.5*

Acquisitions. *The decrease in our proved undeveloped reserves during 2015 was offset by an increase of 123.4 Bcfe which resulted primarily from our acquisitions of oil and natural gas properties completed during 2015. As described below, 34.5 Bcfe of our proved undeveloped reserves acquired during 2015 were drilled in place of proved undeveloped reserves scheduled to be drilled as part of our year end drilling program.*

Revisions. *The decrease in proved undeveloped reserves during 2015 resulted from (i) a decrease of 64.7 Bcfe due to changes in prices and (ii) a decrease of 69.6 Bcfe due to revisions in the timing of our drilling development plan, primarily in the Arkoma, Permian and Powder River Basins, and the re-allocation of drilling of capital expenditures to more promising drilling opportunities. These decreases were offset by a net increase of 72.1 Bcfe due to revisions of previous volume estimates* ***attributed to two main factors: (1) better than previously estimated production results from our current and ongoing drilling program in the Green River Basin; and (2)*** *decreases in capital costs and lease operating expenses* ***across the Company resulting in an increase in the economic life of the wells and realization of additional economically recoverable volumes.***

2. ***In response to prior comment 6, you state that you have a reasonable expectation that you will have the financing required to develop your PUDs over the next three years. You also state that the historical practice of financing the development of your PUDs primarily using cash flow from operations will continue in the future. However, it appears that capital expenditures budgeted for the drilling of PUDs over the next three years greatly exceeds the amount actually expended to drill PUDs in the last three years. Please provide us with additional information explaining the basis for your statement that cash flow from operations will be sufficient to finance your drilling development plan and to reduce borrowings under your Reserve-Based Credit Facility. As part of your response, include a schedule showing your planned development expenditures and the related source of capital by year. In addition, tell us more about your expectations regarding the availability of debt and equity financing through the capital markets specifically for PUD development and address the restrictions and covenants associated with currently outstanding debt which limit your ability to incur additional indebtedness.***

Response:

We acknowledge the Staff's comment. As stated in our previous correspondence as well as disclosed in our Form 10-K, our operating cash flows remain the primary funding source of our capital drilling plan. We direct the Staff to Exhibit A of the Supplemental Letter for the requested schedule demonstrating our December 31, 2015 planned development expenditures and the related source of capital by year along with the assumptions used.

As illustrated in Exhibit A of the Supplemental Letter, we spent approximately $23.6 million in the year ended December 31, 2013, $91.8 million in the year ended December 31, 2014 and $74 million in the year ended December 31, 2015 (excluding the $15.2 million spent on converting volumes attributable to Oklahoma acreage acquired in the Eagle Rock Merger (as defined in our Form 10-K)) on developing scheduled and un-scheduled PUDs. As stated in our Form 10-K, we expect to spend approximately 68% (or $386.1 million) of our planned five year future development costs within the next three years as follows: $63.4 million or 11% of expected development costs during 2016, $172.9 million or 30% during 2017 and $149.8 million or 26% during 2018. Approximately 30% of this capital development plan stems from the two recently completed mergers (Eagle Rock Energy ("EROC") and Lime Rock Energy ("LRE")), which in turn are expected to provide both additional operating cash flows to be used in capital expenditures as well as additional liquidity. The decrease in expected drilling capital spending for 2016 is attributed to the continued decline in commodity pricing, while the increase in each of 2017 and 2018 capital spending is attributed to the increase in natural gas pricing as per the 5-year New York Mercantile Exchange ("NYMEX") forward strip price at December 31, 2015.

Furthermore, as illustrated in Exhibit A of the Supplemental Letter, we expect our cash flow from operations will enable us to finance our drilling development plan while also reducing borrowings under our Reserve-Based Credit Facility (as defined in our Form 10-K). To the extent oil, natural gas and natural gas liquids ("NGLs") prices do not increase over the coming years as expected per the 5-year NYMEX and our cash flow from operations becomes insufficient to continue financing the development of our PUDs, we would expect to seek additional funding from public and private debt and equity capital resources, joint ventures and asset sales. In an effort to mitigate the impact of the challenging commodity price environment, our management team has formulated an action plan, initiated towards the end of 2015 and completed at the beginning of 2016, to strengthen its cash flow including the following steps:

a. Completed a debt exchange offer resulting in 31% of unsecured $550 million tranche bonds (approximately $168 million at 7.875%) being tendered for exchange at 45 cents on the dollar (approximately $76 million at 7.0%). This step has an expected positive impact of $8 million in our cash flow, and a decrease of $92 million on our leverage.

b. Reduced capital spending from 2015 historical consolidated basis for Vanguard, LRE and EROC from approximately $200 million to $63.4 million. This step has an expected positive impact of $136.6 million increase in our cash flow and our leverage.

c. Completed the sale of certain assets in Permian Basin and Mid Continent generating estimated proceeds of $249.2 million, net of expected 2016 cash flow from the properties of approximately $23 million.

d. Suspended common unit and preferred unit distributions effective February 2016. This step is expected to have a $211 million annual increase in our cash flows.

These steps will provide significant incremental cash flow and are expected to allow us to meaningfully reduce our leverage over the course of 2016 and provide sufficient liquidity to manage the reductions to the borrowing base in our revolving credit facility. In addition, we have the benefit of natural gas, oil and NGL hedges which cover approximately 84%, 89%, and 26%, respectively, of our remaining anticipated 2016 production pursuant to our forecast and 69% of our 2017 natural gas production and 23% of our 2017 oil production. These hedges create a significant amount of cash flow certainty regardless of the volatility in commodity prices.

Based on the foregoing and our internal analysis, per Rule 4-10(a)(26) of Regulation S-X, we have a reasonable expectation that we will have the financing required to develop our PUDs over the next three years.

3. Your response to prior comment 6 states that you would expect to seek additional financing if commodity prices do not increase over the coming years and your cash flow from operations becomes insufficient to continue financing the development of your PUDs. Please tell us whether your statement regarding the sufficiency of cash flow from operations to finance your drilling development plan assumes that commodity prices will increase from current levels.

Response:

We acknowledge the Staff's comment. Our statement regarding the sufficiency of cash flow from operations to finance our drilling development plan assumed that commodity price levels trend in a manner consistent with the 5-year NYMEX at each of the evaluation dates of December 31, 2015 and April 8, 2016.

Management's Discussion and Analysis of Financial Condition and Results of Operations, page 65

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Recent Developments and Outlook, page 65

4. ***We note your response to prior comment 7. Please revise your disclosure to explain why your total proved reserves as of December 31, 2015 increased as result of using the 5-year New York Mercantile Exchange forward strip price at February 29, 2016. As part of your revised disclosure, include the table showing the average annual settlement prices input into your model and the table comparing the reported reserve volumes and the strip pricing volumes from your response.***

   Response:

   We acknowledge the Staff's comment. To address this comment, in future annual reports on Form 10-K we will provide additional disclosure regarding the reasons underlying the results of our reserves sensitivity analysis when deemed necessary similar to the following (certain text from the Form 10-K has been rearranged and, with the exception of the heading, changes are reflected in **bold** type):

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   For example, to illustrate the impact of a sustained low commodity price environment, we present the following two examples: (1) if we reduce the 12-month average price for natural gas by $1.00 per MMBtu and if we reduced the 12-month average price for oil by $6.00 per barrel, while production costs remained constant (which has historically not been the case in periods of declining commodity prices and declining production) our total proved reserves as of December 31, 2015 would decrease from 2,288.9 Bcfe to 2,061.3 Bcfe, based on this price sensitivity generated from an internal evaluation of our proved reserves; and **(2) if natural gas prices and oil prices were derived from the 5-year NYMEX forward strip price (using monthly NYMEX settlement prices through December 2021) at February 29, 2016,** our total proved reserves as of December 31, 2015 would increase from 2,288.9 Bcfe to 2,324.1 Bcfe. **Below is a tabular presentation of the impact on reserves from change in prices depicted in Example (2) above compared to the SEC 12-month average pricing of $2.62 for natural gas and $50.20 (held constant) for oil:**

   Example (2) 5-year NYMEX forward strip price at February 29, 2016:

	2016	2017	2018	2019	2020	2021+[(1)]
Oil ($/Bbl)	$37.99	$42.52	$44.77	$46.23	$47.40	$48.39
Gas ($/MMBtu)	$2.03	$2.53	$2.62	$2.67	$2.77	$2.90

(1) The 2021 and subsequent years prices were not escalated and were held flat for the remaining lives of the properties. Capital and lease operating expenses were also not inflated and held constant for the remaining lives of the properties.

When comparing these settlement prices to the prices of $50.20/Bbl of oil and $2.62/MMbtu of natural gas used to generate our year end December 31, 2015 ("YE2015") reserve report, the average annual price for oil from 2021 forward is 3.7% lower than the YE2015 reserve

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report price and the average annual price for gas from 2021 forward is 10.7% higher than the YE2015 reserve report price. The impact of the 2021 forward prices, as compared to the YE2015 reserve report prices, includes (i) an extension of the economic lives of, (ii) an increase in the economically recoverable volumes from, and (iii) even such volumes did not increase, an increase in realized prices from, gas wells and oil wells with high gas to oil ratios. Oil wells with low gas to oil ratios, or no appreciable gas sales, have shortened economic lives and reduced economically recoverable volumes. Because the Company's asset mix is 68% natural gas, the hypothetical increase in gas reserves was greater than the hypothetical loss of liquid reserves on an MMcfe basis. The following table compares the YE2015 reserve report volumes by product with the strip pricing volumes:

	Net Oil (Bbls)	**Net Gas (Mcf)**	**Net NGL (Bbls)**	**Net MMcfe**
Reserve Report at YE2015	64,074	1,554,186	58,384	2,288,934
02-29-2016 NYMEX Strip Price	63,087	1,596,181	58,225	2,324,054
% Difference	**-1.5%**	**2.7%**	**-0.3%**	**1.5%**

Results of Operations, page 68

5. ***Your response to prior comment 8 identifies the items that account for the difference between the 2015 expected hedge prices and the actual realized prices for 2015. Please tell us about the factors resulting in the differences for "Differentials / Transportation and Processing Fee Deducts" and "Impact from Short Puts" and explain why your disclosure of 2015 expected hedge prices did not reflect the anticipated effect of these items.***

Response:

We acknowledge the Staff's comment. To clarify, the expected hedge price represents the weighted average price of our swaps, three-way collars, short puts and range bonus accumulators derivative contracts in place at December 31, 2015. This would represent the average realized price at the initial point prior to any gathering, processing, and transportation charges to take the production from the wellhead to the respective market/pipeline. Differentials/Transportation and Processing Fee deducts represent the additional costs incurred to move and sell our production. These costs fluctuate on a monthly basis depending on the market used or pricing index used, production levels, changes in gathering and processing fees, and, as such variables are inherently difficult to project accurately. Historically, short puts had no expected impact to our weighted average hedge price, because the short put price was well below expected market price. Due to the impact noted during the year 2015, as short put prices rose above realized market prices, management decided to include the impact of short puts on the weighted average hedge price as of December 31, 2015 in an effort to enhance disclosure. As noted on page 93 of the Form 10-K, the three-way collars and short puts will fluctuate based on their value at settlement date when compared to strip pricing at February 29, 2016. We direct the Staff to Exhibit B of the Supplemental Letter for an example of the calculation and its mechanics when incorporating the three-way collars and short puts into the calculation.

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6. ***Based on the information provided in response to prior comment 8, it appears that the calculations underlying the summary disclosure regarding your hedging program for 2016 are primarily based on fixed price swaps and three-way collars. Please tell us how other derivative contracts (e.g., basis swap contracts) are considered in computing the information used in your summary disclosure. In addition, explain how you calculate the expected impact of three-way collars for purposes of this disclosure.***

   Response:

   We acknowledge the Staff's comment. To clarify, the summary disclosure regarding our hedging program for the year ending December 31, 2016 disclosed on page 93 of our Form10-K is based on fixed prices swaps, three-way collars, puts and range bonus accumulators while it excludes basis swap contracts. Basis swap contracts allow us to hedge at different indices (other than NYMEX) and as such cannot be aggregated while still presenting an accurate picture of realized NYMEX pricing. Basis swap contracts are only used to protect against large swings in regional basis differentials which have no correlation to NYMEX pricing. As such, the detailed disclosure of our basis swaps presented on pages 92, 117, and 118 represent the average realized price for each index. On the other hand, calls sold and swaptions were also excluded for simplification purposes and are presented in detail in our hedge disclosure on pages 91-93 and pages 117-118 of our Form 10-K. We propose in future fillings to include a statement explaining that the summarized calculation represents the impact of swaps, three-way collars, puts and range bonus accumulators only.

Notes to Consolidated Financial Statements

Supplemental Oil and Natural Gas Information, page 134

7. ***Your response to prior comment 10 states that you do not include abandonment costs in your calculation of the standardized measure of discounted future cash flows. Please tell us how you considered the guidance provided by the Division of Corporation Finance to oil and gas producers in a letter dated February 4, 2004 stating that the requirement to disclose "net cash flows" relating to an entity's interest in oil and gas reserves requires the inclusion of the cash outflows associated with the settlement of an asset retirement obligation. This letter is available on our website at http://www.sec.gov/divisions/corpfin/guidance/oilgasletter.htm.***

   Response:

   We acknowledge the Staff's comment. As we stated in our response to comment 10 in our correspondence letter dated April 14, 2016, we excluded abandonment costs as, due to the nature of our long-lived assets, any abandonment cost would not be significant and would be partially offset by salvage values associated with our properties and the net abandonment costs would have a de minimis impact on our discounted future cash flows. We direct the Staff to Exhibit C of the Supplemental Letter as well as the responses to comments 8 and 9 below for further discussion of the materiality of abandonment costs.

8. ***Please explain your basis for the statement made in response to prior comment 10 regarding the significance of abandonment costs to your calculation of the standardized***

measure of discounted future cash flows. Also address the significance of abandonment costs to the line item in this calculation for future development costs. As part of your response, provide us with a detailed materiality analysis including the amounts for asset retirement obligations and future abandonment costs related to proved undeveloped wells.

Response:

We acknowledge the Staff's comment. Our net costs to plug and abandon our wells are estimated at approximately $30,000 per well. We direct the Staff to Exhibit C of the Supplemental Letter for a schedule disclosing the timing, abandonment cost and present value of the abandonment costs for each of our proved developed producing wells and proved undeveloped locations. The present value of our abandonment costs, net of salvage value, at each of the three years ended December 31, 2013, 2014 and 2015 was $17.2 million, $25.0 million, $39.2 million, respectively. These costs represented 0.94%, 0.84% and 2.27% of our standardized measure of discounted future net cash flows for each of the three years ended December 31, 2013, 2014 and 2015. We determined that the abandonment costs amounted to less than 2.3% of the standardized measure of discounted future net cash flows for each of the years presented in our Form 10-K, and believe such a limited impact to be immaterial for disclosure purposes. In future fillings, we will continue to monitor and assess the impact of abandonment costs on our standardized measure of discounted future net cash flows and make any adjustments if deemed material.

9. Please tell us why salvage value was considered in assessing **the impact of asset retirement obligations** ***on the standardized measure of discounted future cash flows and quantify the salvage value associated with your properties. Refer to FASB ASC 932- 360-50-31.***

Response:

We acknowledge the Staff's comment. The salvage value associated with our properties represents the scrap metal and steel from our casings, pipes and tanks, which by nature have a market value that remains relatively constant. We estimate an average net salvage value of approximately $3,000 per well. We consider the salvage value a cash inflow to the company that would reduce our cash outflow associated with the asset retirement obligation cost, and thus we net salvage value when assessing the impact of asset retirement obligations on the standardized measure of discounted future cash flows.

10. Your response to prior comment 11 shows the individual items that make up the adjustment to your standardized measure of discounted future net cash flows referenced as "Change in production rates, timing and other." Please tell us why the amount described as "change in current period net cash flows (net of production cost)" is not included as part of the adjustment referenced as "Net changes in prices and production costs" if it represents the impact of the decline in commodity prices.

Response:

We acknowledge the Staff's comment. The amount described as "change in current period net cash flows (net of production cost)" was not included as part of the adjustment referenced as "Net changes in prices and production costs" because it represented the impact of the decline in realized commodity prices during the year ended December 31, 2015 on net cash flows during the year ended December 31, 2015. Essentially, it represented the difference between the estimated cash flow in our year ended December 31, 2014 reserve report (using 12 month average pricing) for the production period during the year ended December 31, 2015 compared to actual cash flow realized during the year ended December 31, 2015. In prior years, this amount was insignificant as the decline or increase in current period prices was not significant compared to the decline of commodity prices during 2015.

In accordance with FASB 932-235-50-35(a) the line item "Net changes in prices and production costs" reflects the net changes in sales and transfer prices and in production costs related to *future* production. As such, the line item "Net changes in prices and production costs" in our Form 10-K calculates the discounted impact of the decline in net prices from one period to another as it relates to the same cash flow period. In other words, this line item represents the impact of change in net prices (net of production cost) on the cash flow projections for the periods 2016 and onward when priced at December 31, 2014 compared to December 31, 2015. As disclosed in our correspondence letter dated April 14, 2016, "change in production rates, timing and other" was comprised of multiple adjustments not individually significant including the "change in current period net cash flows (net of production cost)" when compared to the total change in our standardized measure of discounted future net cash flows. In future fillings should there be any individually significant adjustment, we will disclose that adjustment on a separate line item in our tabular presentation of the principal sources of change in our standardized measure of discounted future net cash flows.

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The Company acknowledges that:

- should the Commission or the Staff, acting pursuant to delegated authority, declare the filing effective, it does not foreclose the Commission from taking any action with respect to the filing;

- the action of the Commission or the Staff, acting pursuant to delegated authority, in declaring the filing effective, does not relieve the Company from its full responsibility for the adequacy and accuracy of the disclosure in the filing; and

- the Company may not assert Staff comments and the declaration of effectiveness as a defense in any proceeding initiated by the Commission or any person under the federal securities laws of the United States.

Please direct any questions or comments you have regarding our responses or the Form 10-K to the undersigned by phone at (832) 327-2259 or Douglas V. Getten of Paul Hastings LLP at (713) 860-7340.

Thank you for your assistance.

Very truly yours,

By: /s/ Scott W. Smith
Scott W. Smith
President and Chief Executive Officer
Vanguard Natural Resources, LLC

cc: Richard Robert, Executive Vice President, Chief Financial Officer and Director, Vanguard Natural Resources, LLC
Douglas V. Getten, Partner, Paul Hastings LLP
Ross Pilcik, Partner, BDO USA, LLP