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

April 14, 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
Amendment No. 1 to Registration Statement on Form S-3
Filed March 24, 2016
File No. 333-210329
Post-Effective Amendment No. 3 to Form S-3
Filed March 24, 2016
File No. 333-207357
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 12, 2016, relating to (i) Amendment No. 1 to the Company's Registration Statement on Form S-3 (File No. 333-210329) (the "***Registration Statement***"), which was filed with the Commission on March 24, 2016, (ii) Post-Effective Amendment No. 3 to the Company's Registration Statement on Form S-3 (File No. 333-207357) (the "***Post-Effective Amendment No. 3***"), which was filed with the Commission on March 24, 2016, and (iii) 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.

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General

1. ***Please note that the staff's comments with regard to your Form 10-K for the fiscal year ended December 31, 2015 will need to be resolved before we will be in a position to declare your registration statement or post-effective amendment effective.***

Response:

We acknowledge the Staff's comment that the Staff's comments on the Form 10-K will need to be resolved before the Staff will be in a position to declare the Registration Statement or the Post-Effective Amendment No. 3 effective.

Amendment No. 1 to Registration Statement on Form S-3

Prospectus Cover Page

2. ***In reviewing the Fifth Amended and Restated Limited Liability Company Agreement, it appears the titles of the preferred units you are registering are 7.875% Series A Cumulative Redeemable Perpetual Preferred Units, 7.625% Series B Cumulative Redeemable Perpetual Preferred Units, and 7.75% Series C Cumulative Redeemable Perpetual Preferred Units. Please revise your Calculation of Registration Fee table and prospectus cover page to include the full titles of the preferred units or advise. Refer to Item 501(b)(2) of Regulation S-K.***

Response:

We acknowledge the Staff's comment and have filed with the Commission an Amendment No. 2 to the Registration Statement to modify the Calculation of Registration Fee table and prospectus cover page to include the full titles of the Company's 7.875% Series A Cumulative Redeemable Perpetual Preferred Units, 7.625% Series B Cumulative Redeemable Perpetual Preferred Units, and 7.75% Series C Cumulative Redeemable Perpetual Preferred Units.

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

Business, page 1

Oil, Natural Gas and NGLs Data, page 9

Proved Undeveloped Reserves, page 12

3. ***We note that your projected conversion ratio for the year ending December 31, 2015 was approximately 16%, but that you actually drilled 12% of your PUDs during the year. Please tell us whether any PUDs scheduled for 2015 were rescheduled or removed due to revisions in the timing of your drilling development plan.***

Response:

We acknowledge the Staff's comment. In response to this question, regarding the conversion of PUDs during 2015, please refer to the following table and the explanation below:

	Bcfe	% of Total
Total Proved Undeveloped Reserves December 31, 2014	653.7	100.0%
Expected 2015 Development at December 31, 2014	101.9	15.6%
2015 Converted	78.4	12.0%
2015 Non-Consent	12.9	2.0%
2015 Removed from 5-Year Plan (Operated)	8.0	1.2%
2015 Removed from 5-Year Plan (Non-Operated)	0.9	0.1%
Rescheduled (Operated and Non-Operated)	1.7	0.3%

Of the 101.9 Bcfe, or 15.6% of our total proved undeveloped reserves ("***PUDs***") as of December 31, 2014 ("***YE2014***"), expected to be developed during 2015, 78.4 Bcfe (12.0% of YE2014 PUDs) was converted to the developed category. With respect to the remaining 23.5 Bcfe (3.6% of YE2014 PUDs), the continued decline in oil and natural gas prices during 2015 resulted in (i) the revision of 12.9 Bcfe (2.0% of YE2014 PUDs) to 0.0 Bcfe as the company decided not to participate in selected non-operated wells, (ii) the removal from our 5-year drilling development plan of 8.0 Bcfe (1.2% of YE2014 PUDs) as the company elected not to develop certain wells in favor of spending capital in areas with better economic returns, (iii) the removal from our 5-year drilling development plan of 0.9 Bcfe (0.1% of YE2014 PUDs) as our non-operated partners elected not to develop certain wells and (iv) the rescheduling of 1.7 Bcfe (0.3% of YE2014 PUDs) to later years within our 5-year drilling development plan.

4. We note that approximately 34.5 Bcfe of PUDs acquired during 2015 were drilled during the year ended December 31, 2015. Please tell us how your plans to drill recently acquired PUDs will affect your development schedule for other PUDs. Your response should also explain how the deferral of these PUDs is expected to impact your ability to drill them within five years of the date of initial booking. Refer to Rule 4-10(a)(31)(ii) of Regulation S-X.

<u>Response</u>:

We acknowledge the Staff's comment.

As the company grows, organically or through acquisitions, we continually re-optimize our drilling schedule by integrating newly acquired PUDs. Our revised drilling schedule includes only those PUDs that have a projected positive cash flow, fall within a five-year window from the booking date and for which a final investment decision has been made. With these parameters in mind, our drilling development plan was re-optimized following our 2015 mergers with Eagle Rock Energy Partners, L.P. and LRR Energy, L.P., which has resulted in some reserves being dropped from the development plan due to the fact they will not be drilled within five years from the booking date and other reserves being added to the drilling development plan due to the aforementioned mergers.

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As additional information, we recently signed a letter of intent to divest certain assets that include a significant number of PUD locations. As a result, we will again re-optimize our drilling schedule upon the consummation of this divestment.

5. Please provide us with additional detail explaining the increase to your PUDs due to revisions of previous volume estimates during the fiscal year ended December 31, 2015.

Response:

We acknowledge the Staff's comment. The increase in our PUDs as a result of volume estimate revisions for PUD locations from YE2014 to December 31, 2015 ("***YE2015***") is attributable to two factors. First, in the Green River Basin, the company participated as a non-operated partner in the drilling and completion of directional wells in the Pinedale field as part of a continuous and ongoing drilling development program. Results from the wells drilled, completed, and put to production as part of this program in 2015 were better than previously estimated. This resulted in an increase in our volume estimates for the producing wells and, correspondingly, an increase in our volume estimates for the offsetting PUD locations. Also, following the successful completion of the 2015 drilling development program, the development schedule in future years has shifted to include more drilling locations in areas associated with better results. Second, as referenced in the Form 10-K on pages 12 and 136, lease operating expenses ("***LOE***") have declined in all operated and non-operated areas and, as a result, our LOE estimates for PUD locations have been revised downward to reflect this decline. As LOE declines, the economic life of wells increases and additional economically recoverable volumes are realized, assuming the same volume forecast and price.

6. You state that you expect to spend approximately 68% of your planned five year future development costs within the next three years. Please tell us about your plans to finance the development of your PUDs during this time considering the expected reduction in your borrowing base and your stated intention to use available liquidity to pay down debt under your credit facility. Refer to Rule 4-10(a)(26) of Regulation S-X.

Response:

We acknowledge the Staff's comment. At the time our drilling development plan was created, we did not factor in a reduction in the borrowing base under our Reserve-Based Credit Facility in our forecast. We did not factor in any expected borrowing base adjustment because historically we have financed the development of our PUDs primarily using cash flow from operations, as opposed to borrowings under our Reserve-Based Credit Facility, and we expect to continue doing so in the future.

As stated on pages 68, 79 and 83 of the Form 10-K, we expect to generate "a substantial amount of excess cash flow over the course of 2016 which will be used to reduce borrowings under our Reserve-Based Credit Facility." However, we did not intend for this statement to suggest that such excess cash flow would be diverted from financing our development plan. We fully expect our cash flow from operations will be sufficient to finance our drilling development plan at the same time we reduce borrowings under our Reserve-Based Credit Facility. Further, although we have not historically used our Reserve-Based Credit Facility for this purpose, to the extent we pay down our borrowings in an amount greater than any reduction in our borrowing base, we will have

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increased liquidity that could be used for financing our drilling development plan if we opt to use our Reserve Based Credit Facility to finance our drilling program.

To the extent oil, natural gas and natural gas liquids (“***NGLs***”) prices do not increase over the coming years and our cash flow from operations becomes insufficient to continue financing the development of our PUDs at the same time we reduce borrowings under our Reserve-Based Credit Facility, we would expect to seek additional financing.

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.

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

Recent Developments and Outlook, page 65

7. You state that total proved reserves as of December 31, 2015 would increase if assumed prices were based on the 5-year New York Mercantile Exchange (NYMEX) forward strip price at February 29, 2016. Please provide us with a narrative explaining the impact of using these NYMEX forward strip prices on the quantities of reported proved reserves as of December 31, 2015 and tell us what assumptions were used for prices beyond the year 2020. With your response, tell us if these prices were input in your cash flow analysis as individual monthly or average annual figures and provide us with a table summarizing the prices by product (i.e., oil, natural gas, and NGLs) over the life of the proved reserves.

Response:

We acknowledge the Staff’s comment. Prices input into our cash flow analysis were calculated using monthly NYMEX settlement prices through December 2021, as reported on February 29, 2016. These monthly settlement prices were then used to generate average annual settlement prices. The following table shows the monthly settlements prices that were used:

Settlement Prices as of 02/29/2016 from *cmegroup.com*		
Month	**NYMEX Oil ($/Bbl)**	**NYMEX Gas ($/MMbtu)**
16-Apr	$33.75	$1.71
16-May	$35.58	$1.81
16-Jun	$36.87	$1.90
16-Jly	$37.79	$1.99
16-Aug	$38.50	$2.03
16-Sep	$39.10	$2.05
16-Oct	$39.63	$2.09
16-Nov	$40.11	$2.23
16-Dec	$40.54	$2.46
17-Jan	$40.93	$2.60

17-Feb	$41.30	$2.60
17-Mar	$41.63	$2.56
17-Apr	$41.94	$2.41
17-May	$42.23	$2.41
17-Jun	$42.49	$2.45
17-Jly	$42.72	$2.50
17-Aug	$42.95	$2.51
17-Sep	$43.17	$2.50
17-Oct	$43.39	$2.52
17-Nov	$43.61	$2.59
17-Dec	$43.83	$2.73
18-Jan	$43.95	$2.83
18-Feb	$44.10	$2.81
18-Mar	$44.25	$2.75
18-Apr	$44.40	$2.48
18-May	$44.56	$2.47
18-Jun	$44.74	$2.51
18-Jly	$44.85	$2.54
18-Aug	$44.97	$2.55
18-Sep	$45.11	$2.54
18-Oct	$45.26	$2.56
18-Nov	$45.43	$2.63
18-Dec	$45.62	$2.77
19-Jan	$45.68	$2.86
19-Feb	$45.76	$2.85
19-Mar	$45.85	$2.78
19-Apr	$45.97	$2.52
19-May	$46.10	$2.52
19-Jun	$46.24	$2.55
19-Jly	$46.27	$2.59
19-Aug	$46.33	$2.61
19-Sep	$46.42	$2.60
19-Oct	$46.55	$2.63
19-Nov	$46.71	$2.70
19-Dec	$46.90	$2.84
20-Jan	$46.96	$2.94
20-Feb	$47.04	$2.93
20-Mar	$47.12	$2.87
20-Apr	$47.21	$2.63
20-May	$47.31	$2.62

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20-Jun	$47.43	$2.65
20-Jly	$47.44	$2.69
20-Aug	$47.48	$2.71
20-Sep	$47.55	$2.71
20-Oct	$47.64	$2.74
20-Nov	$47.75	$2.81
20-Dec	$47.90	$2.97
21-Jan	$47.94	$3.08
21-Feb	$48.00	$3.06
21-Mar	$48.08	$3.00
21-Apr	$48.18	$2.75
21-May	$48.29	$2.74
21-Jun	$48.42	$2.77
21-Jly	$48.43	$2.81
21-Aug	$48.47	$2.84
21-Sep	$48.54	$2.84
21-Oct	$48.64	$2.88
21-Nov	$48.76	$2.96
21-Dec	$48.90	$3.12

As referenced on pages 38 and 66 of the Form 10-K, the 60-month average of the settlement prices listed in the table above resulted in $44.28/Bbl of oil and $2.57/MMBtu of natural gas. However, the resulting average annual settlement prices (derived from the monthly settlement prices) input into the cash flow model are detailed in the following table:

	2016	**2017**	**2018**	**2019**	**2020**	**2021+**
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

***NGL prices are calculated as a percentage differential to Oil price**

The 2021+ prices were not escalated and were held flat for the remaining lives of the properties. Capital and LOE were also not inflated and were 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 YE2015 reserve report, the average annual price for oil from 2021 forward is 3.7% lower than the YE2015 reserve 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.

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The following table compares the YE2015 reserves report volumes 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%**

Because the company's asset mix is 68% natural gas, the expected increase in gas reserves was greater than the loss of liquid reserves on an MMCFE basis.

Results of Operations, page 68

8. You disclose average realized prices, including hedging for the fiscal year ended December 31, 2015 of $3.13 per Mcf for gas, $56.89 per Bbl for oil, and $13.68 per Bbl for NGLs. Disclosure in your December 31, 2014 Form 10-K regarding 2015 indicates that 82% of anticipated gas production was hedged at $4.32 per MMBtu, 77% of anticipated oil production was hedged at $76.12 per Bbl, and 9% of anticipated NGL production was hedged at $46.34 per Bbl. Please provide us with a reconciliation of the material differences between realized prices including the effect of your hedging program and the information provided in the prior year reflecting your expectations for 2015. With your response, include the calculations underlying the summary disclosure on page 92 of your Form 10-K regarding your hedging program for 2016.

Response:

We acknowledge the Staff's comment. The 2015 expected hedge prices for oil, natural gas and NGLs that are disclosed in our Form 10-K for the fiscal year ended December 31, 2014 did not take into consideration the impact to our 2015 realized prices of (i) changes in our actual hedge volumes and weighted average prices for 2015, (ii) production volumes that are not hedged, (iii) changes to our realized price due to differentials and (iv) other revenue deductions and losses due to short puts that were sold in 2015.The total of these four items account for the majority of the difference between the 2015 expected hedge prices and the actual realized prices for 2015. The following table shows the impacts related to these items for each product:

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	Oil	Natural Gas	NGLs
2014 Form 10-K Forecast for 2015 Hedge Price	$76.12	$4.32	$46.34
Adjustments due to:			
Actual 2015 Hedges	($0.08)	($0.04)	($7.32)
Unhedged Volumes	($4.27)	($0.23)	($15.21)
Differentials/Transportation and Processing Fee Deducts	($6.85)	($0.83)	($10.16)
Impact from Short Puts	($7.74)	($0.12)	—
Other	($0.29)	$0.03	$0.03
Total Adjustments to Hedge Price	**($19.23)**	**($1.190)**	**($32.660)**
2015 Realized Prices	**$56.89**	**$3.13**	**$13.68**

The following tables show the calculations underlying the summary disclosure on page 92 of the Form 10-K regarding our hedging program for 2016:

	2016	2017
Gas		
Total Anticipated Production	108,815	99,390
Anticipated Volumes Hedged	84,869	48,213
% Anticipated Production Hedged	**78%**	**49%**
Oil		
Total Anticipated Production	4,952	4,366
Anticipated Volumes Hedged	3,303	918
% Anticipated Production Hedged	**67%**	**21%**
NGLs		
Total Anticipated Production	4,185	3,707
Anticipated Volumes Hedged	907	—
% Anticipated Production Hedged	**22%**	**—**

	2016	2017
Gas		
Fixed Price Swaps:		
Notional Volume (MMBtu)	72,059	31,788
Fixed Price ($/MMBtu)	$4.38	$4.29

Three Way Collars:		
Notional Volume (MMBtu)	12,810	16,425
Floor Price ($/MMBtu)	$3.95	$3.92
Ceiling Price ($/MMBtu)	$4.25	$4.23
Put Sold ($/MMBtu)	$3.00	$3.37
Total:		
Notional Volume (MMBtu)	84,869	48,213
Weighted Average Price ($/MMBtu)	**$4.15**	**$3.84**
Oil		
NYMEX Fixed Price Swaps:		
Notional Volume (MBbls)	1,876	750
Fixed Price ($/MBbl)	$84.01	$85.70
LLS Fixed Price Swaps:		
Notional Volume (MBbls)	—	168
Fixed Price ($/MBbl)	—	$91.25
Puts:		
Notional Volume (MBbls)	366	—
Fixed Price ($/MBbl)	$60.00	—
Three Way Collars:		
Notional Volume (MBbls)	1,061	—
Floor Price ($/MBbl)	$90.00	—
Ceiling Price ($/MBbl)	$96.18	—
Put Sold ($/MBbl)	$73.62	—
Total:		
Notional Volume (MBbls)	3,303	918
Weighted Average Price ($/MBbl)	$67.52	$84.13
NGLs		
Fixed Price Swaps:		
Mont Belviu Propane		
Notional Volume (MBbls)	456	—
Fixed Price ($/MBbl)	$23.62	—
Mont Belviu N. Butane		
Notional Volume (MBbls)	201	—
Fixed Price ($/MBbl)	$28.54	—

Mont Belviu Isobutane		
Notional Volume (MBbls)	96	—
Fixed Price ($/MBbl)	$28.54	—
Mont Belviu N. Gasoline		
Notional Volume (MBbls)	154	—
Fixed Price ($/MBbl)	$53.50	—
Total:		
Notional Volume (MBbls)	907	—
Fixed Price ($/MBbl)	$30.31	—

Notes to Consolidated Financial Statements

Supplemental Oil and Natural Gas Information, page 134

9. ***Please tell us why development costs used to calculate the standardized measure of discounted future net cash flows on page 137 of your filing decreased by approximately 21% while your reported quantities of proved undeveloped reserves decreased by approximately 3% from the prior year. Your response should include a comparison of future development costs used in your calculation of the standardized measure of discounted future net cash flows to recent unit development cost actually incurred.***

Response:

We acknowledge the Staff's comment. The reduction in our development costs is directly related to a reduction in our service costs as a result of the low commodity price environment. The best example of this is the company's participation as a non-operating partner in the continuous and ongoing development program in the Pinedale field. QEP Resources, Inc. and Ultra Petroleum Corp., as operators of the Pinedale field, have successfully reduced the total drilling and completion costs in the field by 33% when comparing 2014 actual costs per well to 2015 actual costs per well. At the same time, reduction in LOE during 2015 and incorporation of that lower LOE into the estimate for PUD locations has caused an increase in the economic life of the wells and, as a result, increased economic recovery per well. The following table details this effect with respect to a single well:

	Lease	Well Number	Life (yrs)	Net MMCFE	LOE (M$)	Capital Investment (M$)
YE2014	Rainbow	5xx-30	30	658	378	570
YE2015	Rainbow	5xx-30	40	713	269	385
% Difference			**34%**	**8%**	**-29%**	**-32%**

The PUD locations in the Pinedale field represent 47% of the company's total PUD reserves at YE2015. This decrease in development costs and LOE has occurred in other areas as well, however, the effect has been offset by the additional development costs associated with the PUD reserves acquired through our acquisitions completed during 2015, resulting in an overall decrease in our development costs of only 21%. Additionally, downward PUD reserve revisions in other areas offset the increase in Pinedale PUD reserves, resulting in a decrease in our total PUD reserves of only 3%.

10. The report from your independent petroleum engineering firm includes a statement that abandonment costs were not included in the preparation of their report. Tell us whether abandonment costs are included in your calculation of the standardized measure of discounted future cash flows.

Response:

We acknowledge the Staff's comment. Abandonment costs are not included in our calculation of the standardized measure of discounted future cash flows. We exclude abandonment costs because, 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 minimus impact on our discounted future cash flows.

11. We note that your disclosure of the principal sources of change in your standardized measure of discounted future net cash flows includes a material adjustment for "change in production rates, timing and other." Provide us with a description of the nature of this adjustment and tell us how you considered providing explanatory disclosure. Refer to FASB ASC 932-235-50-35 and 932-235-50-36.

Response:

We acknowledge the Staff's comment. The standardized measure of discounted future net cash flows adjustment referenced as "change in production rates, timing and other" is comprised of multiple adjustments not individually significant when compared to the total change in our standardized measure of discounted future net cash flows, as illustrated in the following table:

Change in production rates, timing and other
(in thousands)

	Total	Significance*
Change in Timing	$ (94,556)	8%
Change in Production Rates	$ 7,870	1%
Change in current period net cash flows (net of production cost)	$ (171,059)**	14%
Change in Other	$ (98,582)	8%
	$ (356,327)	

*Calculated over total changes in the standardized measure of discounted future net cash flows of ($1,253,230).
** Represents the impact of the decline in realized commodity prices during 2015 when compared to the December 31, 2014 SEC reserve price on estimated net cash flows for 2015. Average realized prices, excluding hedging, during 2015 were $40.94/Bbl of oil and $1.81/MMBtu of natural gas compared to the SEC 12-month average price of $94.87/Bbl of oil and $4.36/MMBtu of natural gas at December 31, 2014.

Per FASB ASC 932-235-50-35 and 932-235-50-36, individually significant adjustments are to be presented separately in the presentation of the aggregate change in the standardized measure of discounted future net cash flows. We note that going forward in future filings 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, the Registration Statement, the Post-Effective Amendment No. 3 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: Scott W. Smith, President, Chief Executive Officer and Director, Vanguard Natural Resources, LLC
Douglas V. Getten, Partner, Paul Hastings LLP
Ross Pilcik, Partner, BDO USA, LLP