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June 30, 2010

Division of Corporation Finance
Securities and Exchange Commission
100 F Street, NE
Washington, DC 20549-7010
Attention: Mr. H. Roger Schwall, Assistant Director

Re: Chesapeake Energy Corporation
Form 10-K for the Fiscal Year Ended December 31, 2009
Filed March 1, 2010
Form DEF 14A
Filed April 30, 2010
Form 10-Q for the Fiscal Quarter Ended March 31, 2010
Filed May 10, 2010
File No. 001-13726

Ladies and Gentlemen:

This letter sets forth the responses of Chesapeake Energy Corporation to the comments of the staff (the "Staff") of the Division of Corporation Finance of the Securities and Exchange Commission received by letter dated June 16, 2010. We have repeated below the Staff's comments and followed each comment with the company's response.

Form 10-K for the Fiscal Year Ended December 31, 2009

Business, page 1

1. **You state that you are the second largest producer of natural gas in the U.S on pages 1, 5 and 41. Provide us with supplemental support for that statement.**

   Response:

   We based the statement that we were the second largest producer of natural gas in the U.S. on publicly available quarterly production information issued by natural gas producers. We have attached as Exhibit 1 a schedule showing daily U.S. natural gas production for the fourth quarter of 2009, as reported by the companies listed.

Well Data, page 7

2. **Provide geographic area disclosure for your productive oil and gas wells comparable to the disclosure you provide under "Drilling Activity" and "Natural Gas and Oil Reserves."**

   Response: We believe our disclosure of productive oil and natural gas wells is fully compliant with Regulation S-K Item 1208(a). "Geographic area," as defined in Regulation S-K Item 1200(d), means country, group of countries or continent, as applicable. For us, disclosures on a company-wide basis satisfy the geographic area requirement since all of our properties and operations are located in one country, the United States.

Production, Sales, Prices and Expenses, page 8

3. **Provide the field level disclosure required by Item 1204(a) of Regulation S-K.**

   Response: We understand that Item 1204(a) requires us to disclose production for the last three fiscal years by geographic area and for each field that contains 15% or more of our total proved reserves. We believe our disclosure of production on a company-wide basis on page 8 is fully compliant with the first requirement, geographic area, as all of our production was from U.S. properties. We believe the field level disclosure requirement is satisfied by the production table on pages 56 and 57 in *Management's Discussion and Analysis*. There we provided a breakdown of our production for each of 2009, 2008 and 2007 from our Big 6 Shale plays as well as other operating areas. The Barnett and the Fayetteville, each a field, accounted for 24% and 15%, respectively, of our natural gas equivalent proved reserves as of December 31, 2009 as reflected on page 9. We thought this detailed presentation of production, along with unit prices received, helped readers understand the changing regional mix of our natural gas and oil operations over these three years and the powerful impact price had on our results of operations as reflected in the line item natural gas and oil sales. In future filings, we propose to provide a cross reference on page 8 to this more detailed presentation of production in *MD&A*.

Natural Gas and Oil Reserves, page 9

4. **Although you have disclosed how many proved undeveloped reserves you converted to proved developed reserves in 2009 and how many proved undeveloped reserves you removed due to not developing them within five years, you have not disclosed any other changes to proved undeveloped reserves. Please revise your document to discuss the changes that correspond to the line item reserve changes found in paragraph 932-235-50-5 of FAB ASC**.

   Response: In the first full paragraph on page 10, we stated that the 1.963 tcfe increase in proved undeveloped reserves was "partially attributable to our ability to report additional proved reserves under new reserve recognition rules as of year-end 2009 . . . . " We did not quantify the effect the new rules had on the reserves reported at year-end 2009 (see response to comment 10 below) but provided additional explanation on pages 64 and 65 by noting that the new rules allowed us to book PUD reserves at year-end 2009 for more than one location offsetting production in the Barnett and Fayetteville Shale plays. The other material changes in PUD reserves noted on page 10 are the conversion of 432 bcfe of PUDs to proved developed reserves during 2009 and the deletion of 580 bcfe of natural gas and oil reserves associated with locations not expected to be developed within five years. We believe our disclosure complies with the requirement of Regulation S-K Item 1203(b) to "disclose material changes in proved undeveloped reserves that occurred during the year, including proved undeveloped reserves converted into proved developed reserves."

   We acknowledge your request for revisions of our disclosure to discuss changes that correspond to the line item reserve changes found in ASC 932-235-50-5. However, this standard applies to changes to an entity's total proved reserves, and we have provided the tabular information required on page 128 in the Supplemental Disclosures About Natural Gas and Oil Producing Activities in Note 10 of the notes to our consolidated financial statements. Below the table on page 128 we discussed the material changes in total proved reserves, and we provided a cross reference to this note in the last paragraph of page 10 in an effort to help readers understand the changes in our estimated proved reserves during the 2007–2009 period. We are not aware of any guidance that requires registrants to apply the rollforward categories applicable to total reserves in the referenced accounting standard to the changes in PUD reserves disclosures required by Item 1203(b). We note, for example, that there is no category in ASC 932-235-50-5 to account for PUDs converted into proved developed reserves, a disclosure item specifically called for in Item 1203(b).

Reserves Price Sensitivity, page 11

5. **Tell us why you believe the use of the 10-year average NYMEX strip prices yield "a better indication of the likely economic producibility" of your reserves than the trailing average 12-month price required by the definitions of Rule 4-10(a)(22)(v) of Regulation S-X.**

   Response: Reserve volumes represent estimated production to be sold in the future. Futures prices, such as the 10-year average NYMEX strip prices, represent an unbiased consensus estimate by market participants about the likely prices to be received for our future production. We hedge substantial amounts of future production based on futures prices. Further, as stated on page 11, Chesapeake uses such forward-looking market-based data in developing its drilling plans, assessing its capital expenditure needs and projecting future cash flows. While historical data, such as the trailing 12-month average price required by the SEC's reporting rule, facilitate comparisons of proved reserves from company to company and may be helpful in discerning trends, such as price-related effects on end-user demand, the price at which we can sell our production in the future is by far the major determinant of the likely economic producibility of our reserves. We also note that a 12-month average price adjusts slowly to falling or rising prices, further detracting from its usefulness as a predictor of the prices at which future production will actually be sold.

6. **Please revise your disclosure to clarify the alternative amounts disclosed using the 10-year average NYMEX strip prices are not proved reserves, as defined in Rule 4-10(a)(22) of Regulation S-X.**

   Response: We note that the suggested tabular format in Regulation S-K Item 1202(b) for this optional reserves sensitivity table uses the term "Proved Reserves" as the column heading for the quantities of oil and gas shown under different pricing scenarios, so it seems the SEC envisioned a table that showed how "proved reserves" would change under different price or cost assumptions. Our reserves sensitivity table on page 11 has two clearly labeled rows: (i) the first for the natural gas and oil quantities and associated present value resulting from the use of "2009 12-month average prices reflected in our reported reserve estimates" (the SEC pricing required, as described throughout the Form 10-K, to calculate "proved reserves") and (ii) the second for optional reserves sensitivity information based on 10-year average NYMEX strip prices at December 31, 2009. Should we use this form of reserves sensitivity table in the future, we will further clarify by footnote that only the data reflected in our reported proved reserve estimates (SEC pricing) are "proved reserves," as defined in Regulation S-X Rule 4-10(a)(22).

Acreage, page 15

7. **You provide by geographic area your developed and undeveloped acreage. However, you do not provide how many acres will be expiring in the next several years. Please see paragraph (b) of Item 1208 of Regulation S-K. We note the risk factor disclosure on page 31. Please revise your document as necessary.**

   Response: We actively acquire new leases, most of which have a three- to five-year term. Managing lease expirations to ensure that we do not experience unintended material expirations is an important part of our business. Our leasehold management efforts include scheduling our drilling to establish production in paying quantities in order to hold leases by production, timely exercising our contractual rights to pay delay rentals to extend the terms of leases we value, planning leasehold asset sales and joint ventures to highgrade our lease inventory or to raise capital for additional development, and letting some low-value leases expire. We maintain a very large drilling program (2,206 gross and 1,003 net wells drilled in 2009) that is rigorously scheduled to lock in our acreage with the highest prospective value. The fact that we control a substantial rig fleet (lease or own 98 drilling rigs currently) and other service operations gives us a high degree of confidence that we will be able to execute our drilling plans. The risk factor you refer to on page 31 reminds readers that plans may change for many reasons, a caution that seems entirely appropriate (and not inconsistent) in view of our substantial lease holdings and level of drilling activity.

   Regulation S-K Item 1208(b) requires an indication of the minimum remaining terms of leases, <u>if material</u>. We determined that the amount of undeveloped leasehold that we reasonably believe will be abandoned or allowed to expire at the end of the lease term is immaterial to our operations. In our future filings, we will provide in Item 1 a description of our leasing activity, the steps we take to avoid unwanted lease expirations and, if appropriate, describe the minimum remaining terms of our leasehold acreage over the next several years.

8. **Please disclose if you have any delivery commitments that must be fulfilled for your oil and gas production. Please see Item 1207 of Regulation S-K.**

   Response: We believe we had no delivery commitments that were required to be disclosed pursuant to Regulation S-K Item 1207.

Results of Operations, page 55

Production expenses, page 58

9. **We note your calculation of production expenses includes ad valorem taxes. Item 1204(b)(2) of Regulation S-X states the disclosure of average production cost by geographical area should not include ad valorem and severance taxes. Please revise your disclosures here and throughout your filing to remove such amounts from the calculation of production expenses.**

   Response: The lead-in sentence to the table on page 58 states that the table shows production expenses by region (in our view satisfying the requirement of Regulation S-K 1204(b)(2)) and also shows our ad valorem tax expenses for the three years presented. In order to avoid confusion, we propose in future filings to subtotal production expenses without ad valorem taxes (and so label the subtotal line), followed by the ad valorem taxes line and summed so that the information foots to the line item *production expenses* in our statements of operations. We considered including the table, without the line for ad valorem taxes, in Item 1 but concluded it was more useful for the reader to consider such information in the context of our results of operations discussion in *MD&A* and did not think repetition of the information was necessary.

Application of Critical Accounting Policies, page 61

Natural Gas and Oil Properties, page 63

10. **We note your discussion at the bottom of page 64 of the increase in proved undeveloped reserve volumes from December 31, 2008 to December 31, 2009 that are attributable in part to the modernized rules allowing for the use of more than one direct spacing areas offsetting producing wells when determining quantities of proved undeveloped reserves. Additionally, we note your discussion on page 11 of the difference in oil and gas quantities calculated when using the trailing average 12-month price versus the 10-year average NYMEX strip prices. However, you have disclosed on page 64 that it is impractical for you estimate the effect of adopting the new reserve rules. Based on the surrounding disclosure in your filing, it is unclear why it is not practical to discuss the impact of adopting the new rules. Please revise your disclosure or tell us in more detail why you believe this information is impractical to provide.**

Response: To be able to report accurately the estimated quantitative effect of applying the oil and gas modernization rules would have required us to prepare two sets of reserve reports, one applying the new oil and gas modernization rules and the second applying the rules in effect at year-end 2008. We determined that it was not practicable to devote the time and personnel resources necessary to prepare duplicate sets of reserve reports, as stated on page 148 in our discussion in Note 20 of the January 2010 FASB update of its oil and gas estimation and disclosure requirements:

> The company is not able to disclose the effects resulting from the implementation of these [rule] changes on the financial statements or on the amount of proved reserves and disclosed quantities because personnel and time constraints made it infeasible for the company to perform a second reserve estimation process under the prior standards.

The year-end reserve reporting process begins months before the Form 10-K filing deadline, both for us internally and for the third-party engineering firms we engage to prepare reserves reports at year-end (four third-party reports covered 83% of our proved reserves at year-end 2009, including 100% of our major asset areas in the Barnett, Fayetteville, Haynesville and Marcellus shale plays). Preparing a second set of reserve reports would have been a very considerable undertaking.

The rule changes resulted in changes in our reporting methods. Chesapeake used both deterministic and probabilistic methods to estimate its year-end 2009 proved undeveloped reserves as permitted by the new rules. In prior years, we had used only the deterministic method. While it is true that both methods result in equivalent reserves at the field level, they are not equivalent for any individual well. Chesapeake conducts the majority of its PUD reserve estimates at the well level. With interests in some 10,000 non-producing reserve cases at December 31, 2009, only full reports prepared using new rules and old rules would provide a proper basis of comparison. Further, the significance of the change in pricing method could be assessed only by preparing reserve reports under both the new 12-month average price and the prior single-day year-end price. Some undeveloped projects may be economic under one pricing scenario but not another. The alternative pricing scenario we provided on page 11 was intended to show the sensitivity that our proved reserves have to price fluctuations, as well as a view of management's analysis of future prices, but both scenarios were based on our reserve estimates prepared under the new rules. Finally, the information obtained from dual reserve reports using old rules and new rules would be relevant only for rule transitional purposes.

11. **You indicate that in the Barnett Shale and the Fayetteville Shale you attributed proved undeveloped reserves to locations more than one offset location away from an existing well. Disclose the average number of offset locations away from an existing well you attributed proved reserves to in each of those formations.**

Response: To assist your understanding of our PUD booking process in the Barnett Shale and the Fayetteville Shale, we are providing below offset location information, including the average number of offset locations away from an existing well to which we attributed proved reserves:

Barnett

- 1.35 average locations away from an existing PDP
- 76% of PUDs one location away from PDP
- 94% of PUDs two or less locations away from PDP
- No PUDs booked more than one mile away from an existing producing well
- No PUDs booked more than one location away from PDP if moving in a direction away from

established production

Fayetteville

- 1.43 average locations away from an existing PDP
- 72% of PUDs one location away from PDP
- 91% of PUDs two or less locations away from PDP
- No PUDs booked more than one mile away from PDP
- No PUDs booked more than one location away from PDP if moving in a direction away from established production

You should also disclose the technology and methods used to establish the reasonable certainty of these reserves.

Response: Regulation S-K Item 1202(a)(6) calls for "a general discussion of the technologies used to establish the appropriate level of certainty for reserves estimates from material properties included in the total reserves disclosed." We believe our disclosure in the carryover paragraph at the bottom page 64, quoted below, meets this requirement of a "general discussion" of the technologies we used.

> Within the Barnett and Fayetteville Shale plays we used both public and proprietary geologic data to establish continuity of the formation and its producing properties. This included seismic data and interpretations (2-D, 3-D and micro seismic); open hole log information (both vertical and horizontally collected) and petrophysical analysis of the log data; mud logs; gas sample analysis; drill cutting samples; measurements of total organic content; thermal maturity; sidewall cores; whole cores and data measured from our internal core analysis facility. Once the continuous geologic area was established using the data listed above, statistical analysis of established producing wells was used to generate reasonable certainty (defined as 90% probability aggregated to the field level). The analysis required a statistically significant number of producing wells within the defined geologic area and then tested for confidence by insuring the variance in results over time, area and distance was evaluated. Proper development spacing was also statistically analyzed.

We have reservations about expanding such information in a filing considering that our Form 10-K reader is a "reasonable investor," not a technical expert, and we believe the rules do not require lengthy, complex disclosures about technologies used. As stated in the SEC's adopting release for modernization of oil and gas reporting (Rel. Nos. 33-8995, 34-59192),

> We are clarifying that the required disclosure would be limited to a concise summary of the technology or technologies used to create the estimate. A company would not be required to disclose proprietary technologies, or a proprietary mix of technologies, at a level of specificity that would cause competitive harm. Rather, the disclosure may be more general. *For example, a company may disclose that it used a combination of seismic data and interpretation, wireline formation tests, geophysical logs, and core data to calculate the reserves estimate.* As noted, however, the Commission's staff, as part of the review and comment process, may continue to request companies to provide supplemental data, consistent with current practice, which, under the new rules, may include information sufficient to support a company's conclusion that a technology or mix of technologies used to establish reserves meets the definition of "reliable technology." [Emphasis added.]

Consistent with the last sentence quoted above, for your information, the following supporting data provide more granularity to the foregoing disclosure in our 2009 Form 10-K:

Data Within Study Area of Each Play	**Barnett**	**Fayetteville**
Producing wells	6,780	1,814
Operated producing wells	1,554	507
Non-operated producing wells	263	1,307
Non-operated wells with daily production/pressure	87	1,291
Square miles of 3D seismic	1,035	1,445
Miles of 2D seismic	2,371	1,619
Number of micro-seismic tests	27	9
Footage of whole core	3,915	4,171

Number of sidewall cores	818	222
Wells with open hole logs (vertical, minimum porosity & resistivity)	281	357
Wells with open hole logs (horizontal, minimum porosity & resistivity)	2	24
Total organic carbon data points	657	776
Thermal maturity data points	582	646
Pressure observation wells	2	0

The major aspects of the statistical method include:

- Establishing a common geologic analogue area based on the data described above.
- Testing the geologic area for any measureable dependencies between a geologic or reservoir quality parameter and actual production results.
- Using an iterative process that systematically selects producing wells as anchor points.
- Distributions of the remaining producing wells' estimated ultimate recoveries (EURs) are then evaluating at various distances from the anchor points.
- Adhering at all times to the rules for statistical significance of the data sets.
- Creating a reliable, repeatable result as the iterative process allows for multiple non-unique solutions to be compared simultaneously.
- Establishing a single point of comparison for each distribution—a point halfway between the mean and the 50% probability (labeled P^).
- Checking variances to insure each result yields a distance from the anchor points that is no more than 10% different than the anchor set P^ value. The principle used is the Law of Transitive Properties (if A = B and B = C, then A = C).
- "Stacking" these distance-based multiple solutions in a map view and then evaluating them in total to decide the extent of the proved area.
- After the proved area has been verified, evaluating statistically the established spacing of the play within the proved area. That is, only PUDs at spacing that has been actually tested at a statistically significant producing well count are booked as proved undeveloped reserves.
- Statistically booking the PUDs within the proved play area to achieve 90% probability outcomes within the localized area of analogous results.
- Limiting PUDs to one location offsets to producing wells when moving away from established field production.

The statistical analysis we used is a rigorous empirical method to achieve reliable technology. It was extensively reviewed by multiple industry reservoir engineering consulting firms. It was also extensively reviewed by individuals who are highly respected within the energy industry as leaders in the fields of statistical analysis and application of SEC rules. As Chesapeake matured the methodology, it was presented at an industry forum of peer producing companies. The method represents the core evaluation technique being issued by a committee of the Society of Petroleum Evaluation Engineers ("SPEE") commissioned to study the proper analytical techniques for determining PUD reserves within unconventional resource plays. That committee's findings are scheduled to be released later this year. We believe this method, once released by SPEE, will represent the industry best practice and will become the standard by which other techniques are judged.

With a view towards possible disclosure, tell us whether you used volumetric estimates to calculate the proved undeveloped reserves or used analogies of producing wells in the same geologic formations. If analogies were used, disclose the age of the wells that you believe represent an analogy, the cumulative production to date from those wells and the estimated life of those wells and how it was determined.

Response: We used more than one method of reserve estimation to calculate our PUD reserves. Where analogies were used, volumetric calculations were also evaluated to insure recovery factors were within expected limits. Additionally, some computational simulations were used to test the reasonableness of the PUD reserves. In the Barnett and Fayetteville shale plays, the analogues we used were restricted to producing wells from within the same geologic formation and area that were statistically shown to yield consistent production results. Additionally, the ample geologic data we possess indicated the reservoir rock and fluid properties were analogous. Following is additional information on these two plays:

Barnett Shale

- Age of wells – 1,260 total wells with an average age of 2.0 years
    - 97 wells 5 years old or greater
    - 218 wells 4 years old or greater
    - 538 wells 3 years old or greater
    - 722 wells less than 3 years old
- Cumulative production – overall average is 22% of EUR
    - For wells 5 years old or greater, cumulative production averaged 1,135 mmcf per well. This represented 49 percent of the estimated average ultimate recovery of these wells.
    - For wells 4 years old or greater, cumulative production averaged 965 mmcf per well. This represented 36 percent of the estimated average ultimate recovery of these wells.
    - For wells 3 years old or greater, cumulative production averaged 814 mmcf per well. This represented 30 percent of the estimated average ultimate recovery of these wells.
    - For wells less than 3 years old, cumulative production averaged 686 mmcf per well. This represented 19 percent of the estimated average ultimate recovery of these wells.
- Estimated life of wells - Average life of the analogue wells was 49.5 years
- Estimated reserve life of the analogues was calculated using decline curve analysis for each individual well in conjunction with current economic conditions including price, price differentials, lease operating expenses and production taxes. These estimates were checked for reasonableness against volumetric calculations and in some instances computational simulation.

Fayetteville Shale

- Age of wells – 1,130 wells with an overall average age of 1.4 years
    - 56 wells 4 years old or greater
    - 270 wells 3 years old or greater
    - 860 wells less than 3 years old
- Cumulative production – overall average is 19% of production
    - For wells 4 years old or greater, cumulative production averaged 646 mmcf per well. This represented 42 percent of the estimated average ultimate recovery of these wells.
    - For wells 3 years old or greater, cumulative production averaged 628 mmcf per well. This represented 31 percent of the estimated average ultimate recovery of these wells.
    - For wells less than 3 years old, cumulative production averaged 371 mmcf per well. This represented 11 percent of the estimated average ultimate recovery of these wells.
- Estimated life of wells - Average life of the analogue wells was 43 years
- Estimated reserve life of the analogues was calculated using decline curve analysis for each individual well in conjunction with current economic conditions including price, price differentials, lease operating expenses and production taxes. These estimates were checked for reasonableness against volumetric calculations and in some instances computational simulation.

In addition, please tell us if you included these added volumes of reserves under extensions, discoveries and

other additions, or under revisions of previous estimates.

Response: For both the Barnett and the Fayetteville shale plays, these added PUD reserves were considered extensions, discoveries and other additions.

Exhibit 99.1

12. **The reserve report by Netherland Sewell & Associates did not state where the reserves were located that they audited. Please provide a revised letter that complies with Item 1202(a)(8)(iii) of Regulation S-K.**

    While we understand that there are fundamentals of physics, mathematics and economics that are applied in the estimation of reserves, we are not aware of an official industry compilation of such "generally accepted petroleum engineering and evaluation principles". With a view toward possible disclosure, please explain to us the basis for concluding that such principles have been sufficiently established so as to judge that the reserve information has been prepared in conformity with such principles. This comment applies also to Exhibit 99.2.

    Response: We have provided a copy of the relevant Staff comments to, and discussed them with, our principal contact at Netherland Sewell & Associates ("NSAI").

    Item 1202(a)(8)(iii) requires disclosure of the geographic area in which the reserves covered by the subject report are located. NSAI's report included as Exhibit 99.1 disclosed that the reserves audited by NSAI were located in the United States, the only country in which such reserves are located. We believe further detail beyond the standard of geographic area could be helpful to readers, and, after discussion with NSAI, we propose that similar reports included with future filings shall disclose the states or similar regions in which the reserves covered by such report are located.

    In a February 19, 2007 publication of the Society of Petroleum Engineers ("SPE") entitled Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information ("SPE 2007 Standards"), the SPE acknowledges in the foreword section thereof and in section 1.2 that there are "generally accepted engineering and evaluation principles" applicable to the estimation and auditing of oil and gas reserves. The SPE goes further in section 1.2 to define the relationship between such principles and the "principles of physical science, mathematics, and economics." A copy of the SPE 2007 Standards is available for reference at the following website: http://www.spe.org/industry/reserves/docs/Reserves_Audit_Standards_2007.pdf .

    The estimates shown in the report of NSAI included as Exhibit 99.1 have been prepared using the generally accepted principles and methods as promulgated by the SPE in the SPE 2007 Standards, as well as in accordance with applicable standards promulgated by the SEC. We have been informed that NSAI will include reference to the SPE 2007 Standards in future applicable reports included with filings with the SEC.

Exhibit 99.2

13. **We note that the Schlumberger reserve report states that they used the prices from the Henry Hub to calculate the un-weighted arithmetic average natural gas price for 2009. As they evaluated properties located in the states of West Virginia, Kentucky, Pennsylvania, and New York, advise us why they believe that the prices from the Henry Hub, which is located in Louisiana, were the appropriate prices to use for these properties, instead of the New York City hub, or other near-by eastern hub, which they presumably sell into. We note that the average price received in 2009 for gas from the Marcellus Shale, disclosed on page 56, is higher than the price received for the other regions.**

    Response: We have provided a copy of the relevant Staff comments to, and discussed them with, our principal contact at the Data & Consulting Services, Division of Schlumberger Technology Corporation ("Schlumberger").

    Henry Hub is a common reference price point for natural gas production in the U.S. As stated in the report filed as Exhibit 99.2, all prices were adjusted for local differentials, gravity and BTU where applicable. These adjustments are made for each well based on the difference between the twelve-month actual price received by field and the Henry Hub reference price. The basis adjustments account for the fact that the properties evaluated in this report are located in the states of Kentucky, New York, Pennsylvania, Tennessee, Virginia and West Virginia. The resulting per well price used in the individual reserves calculations reflects the actual unweighted arithmetic average price received for the prior twelve-month period.

    We also note that the use of the New York City hub or any other reference price, when adjustments for each well are applied, would not result in different reserves calculations. Given this, we believe there would be no effect or benefit, and may be some disadvantage of complexity, to use a different or additional reference price for calculating reserves in different regions.

14. **The closing paragraph states in part that the report "was prepared solely for the use of the party to whom it is addressed and any disclosure made of this report and/or the contents by said party thereof shall be solely the responsibility of said party, and shall in no way constitute any representation of any kind whatsoever of the undersigned with respect to the matters being addressed." As Item I202(a)(8) of Regulation S-K requires the report, please obtain and file a revised version which retains no language that could suggest either a limited audience or a limit on potential investor reliance. This comment applies also to Exhibit 99.4.**

    Response: We have also provided a copy of the relevant Staff comments to, and discussed them with, our principal contact at Ryder Scott Company ("RSC"). After discussions with Schlumberger and RSC, we propose removing any language that could suggest either a limited audience or a limit on potential investor reliance in similar reports included with future filings with the SEC.

Exhibit 99.4

15. **Item 1202(a)(8)(v) of Regulation S-K requires that the third party report include the primary economic assumptions underlying the reserves estimate. Revise the report to indicate the average price that was used in the reserves calculation.**

    Response: We note that in the second paragraph of RSC's report included as Exhibit 99.4, RSC states:

    > The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the ending date of the period covered in this report, determined as unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements as required by the SEC regulations.

    This statement is repeated in substance under "Hydrocarbon Prices" on page 4 of the RSC report. We believe this statement clearly explains what price assumptions were used by RSC in preparing the report. Importantly, RSC states that it used price assumptions that comply with the regulations promulgated by the SEC. Further, as discussed in comment 13 and as mentioned in the above-quoted statement of RSC, the price used for reserves calculations for each property or well is adjusted for factors such as differentials and contractual arrangements, thus resulting in different prices used in each instance. We believe that RSC disclosed in its report the price assumptions used in preparing the report, but we acknowledge that numerical average prices could be provided. We propose to have our third-party engineers include in their reports the numerical average prices for natural gas and oil along with their price assumptions in similar reports included with future filings with the SEC.

Schedule 14A Definitive Proxy Statement, filed April 30, 2010

General

16. **Please confirm in writing that you will comply with the following comments relating to your proxy in all future filings, and provide us with an example of the disclosure you intend to use in each case. After our review of your responses, we may raise additional comments.**

    Response: Please see our responses to comments 17 and 18.

Compensation Committee, page 12

Executive Officer Compensation, page 13

17. **We note Mr. McClendon is the chairman of your Board of Directors. We also note your disclosure that Messrs. McClendon, Rowland, and Dixon "are responsible for analyzing, developing and recommending base salary adjustments, cash bonuses and restricted stock awards with respect to the executive officers, including themselves, for review, discussion and approval by the Compensation Committee. . . ." Your disclosure, however, does not discuss Mr. McClendon's role in discussions concerning his compensation as CEO. For example, does he attend Compensation Committee meetings? Does he participate in Compensation Committee discussions concerning his compensation? Does he participate in the portion of the Board meetings in which the Compensation Committee recommends his compensation package to the Board? Does he recuse himself from the Board's deliberations and vote with regard to the approval of his compensation package? Please expand your disclosure to describe in greater detail the involvement of the CEO, CFO, and the other named executive officers in the compensation process.**

    Response: Below is an example of disclosure that could be incorporated in future proxy statements to describe in greater detail the involvement of the CEO, COO and CFO in the compensation process. The example is based on the process and procedures in place during 2009 and would necessarily be modified to include any changes implemented by the Compensation Committee or the Board of Directors.

Executive Officer Compensation. Messrs. McClendon, Rowland and Dixon are responsible, in conjunction with the semi-annual evaluation of the Company's other employees, for developing recommended base salary adjustments, cash bonuses and restricted stock awards for the executive officers, including themselves, for the Compensation Committee to review, discuss and vote on during its regularly scheduled meetings in June and December of each year. In order to develop such recommendations, Messrs. McClendon, Rowland and Dixon work as a group to evaluate each executive officer utilizing their experience with each member of the executive officer group and the compensation established for the other members of senior management.

Mr. McClendon generally attends Compensation Committee meetings and as appropriate participates in discussions in order to provide information to the Committee at the June and December meetings regarding the compensation recommended for executive officers. On occasion the Compensation Committee meets in executive session without Mr. McClendon. Messrs. Rowland and Dixon do not generally attend Compensation Committee meetings. After review, discussion, any modifications and a vote on the final executive officer compensation amounts, the Compensation Committee makes a report to the Board for discussion and ratification. Mr. McClendon, not being a member of the Compensation Committee, does not vote at Committee meetings, and he does not vote with respect to the Board's acceptance and approval of the Committee's report to the extent it covers his compensation. Mr. McClendon is generally present during the Board's discussions of executive officer compensation and performance but does not attend the Board's quarterly executive sessions, when the non-management directors discuss and assess the Company's overall compensation program, including Mr. McClendon’s performance and compensation in relation to the Company's long-term results and strategy.

Other NEO Compensation, page 32

18. **We note that you do not incorporate "objective performance criteria" into your executive compensation program and that the compensation of the NEOs discussed in this section is based on a comprehensive subjective review of their performance and the Company's performance. For each NEO, you cite certain factors that were considered, among other things. With a view towards possible disclosure, tell us what it was about each of those factors you considered in arriving at their compensation in 2009. For example, for Mr. Rowland, what was it about the Company's hedging program, about the quality of its financial reporting, about its asset financing and monetization strategy, etc. and his role in those factors that you considered? Likewise, for Mr. Dixon, what was it about the Company's production rates, its finding and development costs, its drilling results, etc. and Mr. Dixon's role in those factors that you considered? To the extent quantifiable data was considered, and for the most part these appear to be factors which are quantifiable, provide us with the results considered by the Committee.**

Response: We wish to clarify that the Compensation Committee has not historically utilized particular quantified data in its NEO performance compensation reviews. As stated, "the compensation was based on a comprehensive subjective review . . . ." By this we mean that each NEO was evaluated based on his overall role in the organization, not on individual metrics or data points. As part of their duties as directors, the members of the Compensation Committee receive and review at least quarterly extensive financial and operational information about the industry, the Company and personnel, including information with respect to the factors identified on pages 32 and 33. In addition, the executive officers or their teams make presentations or facilitate discussions with respect to their areas of responsibility at the Board's quarterly meetings. The Committee makes compensation determinations on the basis of that information and in the context of the Committee members' understanding of the industry, the Company's performance, the effectiveness of the management team and the role of each executive on the team. This was the Committee's process in 2009.

The Committee believes the complexity and interconnectedness of the Company’s activities in creating value makes each individual’s contribution difficult, if not impossible, to measure based on objective data. As an example, although production rates are important to the Company and are thus a factor considered for Mr. Dixon, there is no pre-determined production rate that is used as a metric for determining the success of Mr. Dixon's performance with respect to production. Some of the reasons underlying the Company's decision not to use production rates as an objective measure of executive performance are described on page 27 of the 2010 proxy statement. There are numerous decisions made across the Company that accelerate or defer production based on a number of decision points, including expectations regarding extremely volatile oil and gas prices. Other examples of the areas in which it is impossible to use specific operational metrics to measure the performance of individual executives include asset financing and monetization strategy (a factor for Mr. Rowland), leasehold acquisition efforts (a factor for Mr. Dixon), negotiation and execution of innovative joint venture partnerships (a factor for Mr. Jacobson), and ability to identify new economic natural gas and oil resources (a factor for Mr. Lester). The efforts of each in these and other areas were jointly responsible for the Company's success in exploiting the desire of international energy companies to participate in the U.S. natural gas market through the monetization strategy described on page 23. While the joint venture and sale transactions occurred in two calendar years, the contributing efforts of the management team and each individual occurred over many years.

The Compensation Committee’s role is to attempt on a rolling basis across periods to make an overall assessment of the performance of the executive officer team and the role and relative contribution of each member of that team. That process necessarily includes recognizing the current value created from good work in prior years and anticipating value to be created in the future through current efforts. For a variety of reasons, including those discussed on pages 26-29, the Compensation Committee and the Board do not believe it is possible to devise objective performance metrics that will serve as reliable guides to compensation decisions.

Form 10-Q for the Quarterly Period Ended March 31, 2010

9. Investments, page 27

19. **We recognize that you adopted new guidance for variable interest entities in ASC 820 on January 1, 2010. Under the new accounting guidance, you state that you no longer meet the conditions to be the primary beneficiary of Chesapeake Midstream Partners ("CMP'"); as such, you deconsolidated CMP's financial statements effective January 1, 2010. To help us understand your accounting for the adoption of this new accounting guidance, please:**

    a. **Tell us how you have applied the guidance in ASC 810-10-65-2(e) and ASC 810-10-30-9 to determine and record the cumulative-effect adjustment of $142 million to the current earnings in the quarter ended March 31, 2010.**

Response: In accordance with ASC 810-10-65-2(e), our retained interest in Chesapeake Midstream Partners, L.L.C. ("CMP") was valued based on what the carrying value of the retained interest would have been at the date of formation of CMP in the third quarter of 2009 adjusted for activity occurring from the date of formation of CMP to the date of adoption of the new guidance in ASC 810 (formerly FAS 167). Had the new guidance of ASC 810 applied at the date of formation, we would not have been deemed to be the primary beneficiary of CMP and our initial investment in CMP would have been recorded at fair value in accordance with ASC 810-10-40-5 (formerly FAS 160). Because an independent third party investor, Global Infrastructure Partners ("GIP"), purchased their 50% interest at formation for $587 million, the fair value of our 50% retained interest was also established at $587 million. As the carrying value of our investment at January 1, 2010 exceeded the carrying value of our retained interest (as determined by ASC 810-10-65-2(e)) by $142 million, net of tax, a cumulative-effect adjustment was recorded to retained earnings. We chose to record the cumulative effect prospectively in the period of adoption pursuant to ASC 810-10-30-9.

    b. **Tell us how you calculated the difference between your underlying equity in net assets of CMP over the carrying value of your investment in CMP of $287 million as of March 31, 2010. In your response, please be specific on how you have applied the guidance in ASC 323-10-35-13 in accreting the difference over 20 years.**

Response: The adoption of the new authoritative guidance for variable interest entities did not establish a new basis for the assets inside the partnership, which were recorded in the third quarter of 2009 at Chesapeake's historical cost, which did not include goodwill. The difference between the carrying value of our investment at January 1, 2010 upon the adoption of the new guidance in ASC 810 and our underlying 50% equity in the net assets of CMP and January 1, 2010 is attributable to CMP's gathering assets, which have an estimated remaining useful life of approximately 20 years. Pursuant to ASC 323-10-35-34, the difference between the carrying value of an equity method investee and the investor's underlying equity in the net assets of the investee shall affect the determination of the amount of the investor's share of earnings or losses of an investee as if the investee were a consolidated subsidiary. Therefore, the difference is being accreted over the remaining useful life of 20 years.

Should any member of the Staff have a question regarding our responses to the comments set forth above, or need additional information, please do not hesitate to call Mike Johnson at (405) 935-9229 or me at (405) 935-9232, or you may contact our outside counsel Connie Stamets at (214) 758-1622 at Bracewell & Giuliani LLP.

As you requested in the comment letter, we acknowledge that:

- the company is responsible for the adequacy and accuracy of the disclosure in the filing;
- staff comments or changes to disclosure in response to staff comments do not foreclose the Commission from taking any action with respect to the filing; and
- the company may not assert staff comments as a defense in any proceeding initiated by the Commission or any

person under the federal securities laws of the United States.

Very truly yours,

/s/ MARCUS C. ROWLAND

Marcus C. Rowland
Executive Vice President and Chief Financial Officer

EXHIBIT 1

CHESAPEAKE ENERGY CORPORATION

Fourth Quarter 2009 Daily Natural Gas Production Comparison

Company (a)	Daily Q409 Production (mmcf/day)
ExxonMobil	3,665
Chesapeake	**2,440**
BP	2,313
Anadarko	2,076
Devon	1,894
ConocoPhilips	1,831
EnCana	1,616
Chevron	1,405
Williams	1,177
EOG	1,075
Shell	1,064
Southwestern	966
Apache	689
Occidental	645
El Paso	585
Petrohawk	577
Newfield	500
Ultra	496
Questar	488
Noble	386

(a) Includes independents, majors and pipelines.